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EQUILIBRIUM MODELS FOR ELECTRICITY MARKET

Doctoral Dissertation of:
Majid Gholami

Supervisor:
Asst. Prof. Cristian Bovo

Tutor:
Prof. Alberto Berizzi

The Chair of the Doctoral Program:
Prof. Alberto Berizzi

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Abstract

THIS research consists of two major independent topics; first, Generation Expansion Planning (GEP) models in a realistic framework and second, the islanding condition in presence of Renewable Energy Sources (RES).

The traditional vertically integrated structure of the electric utility has been deregulated in recent years particularly by adopting the competitive market paradigm in many countries around the world. For instance, competitions have been emerged in the European power industry according to the EU-electricity guidelines during the last decade. In addition to these changes in the organization of the electricity market, the EU Emissions Trading Scheme (EU ETS) came into effect in 2005 which will have significant impacts on electricity industry in Europe.

As the direct result of these novel developments, electric firms assume much more risk and become highly responsible for their own economic decisions demanding new models and sufficient tools to cover these new obligations and risks or to formulate their bidding strategies. On the other hand, it is necessary for the system regulator to understand how electric firms formulate their expected profit-maximizing bidding strategy to be able to identify possible market power abuse and limiting such them by introducing appropriate measures.

In addition, the generation activity is more risky than in the past and so it becomes important to develop new tools to help decision makers to analyze the investment. As a result, developing the GEP model in a realistic framework becomes a crucial task. The purpose of this research is to develop a GEP model in a realistic framework.

This first topic proposes a generation expansion planning model with CO_2 emission and transmission constraints to analyze the possible impacts of the European emission trading system and transmission constraints on the power sector. The model will also be improved to analyze the effect of different incentive plans on RES capacity expansion. Further, the proposed model is developed to investigate the influence of already installed power plants in the generation mix.

The possibility of the applying proposed procedures and models to real systems is verified by the numerical results with reference to the Italian electricity market (taking into account the zonal structure) and the EU ETS system as an illustration.

Increasing penetration of RES is the characteristic of modern power systems which makes their integration a challenging problem. However, RES installed at the HV subtransmission level offer a unique opportunity to benefit the possibility of demanded or undesired islanding conditions. In this study, a procedure is proposed to evaluate the viability of the islanded operation which determines the control actions to be performed for real power balance of the island after islanding. The procedure's feasibility is shown via the tests performed on real subtransmission systems.

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CHAPTER 1

Introduction

1.1 Background and Problem Statement

The topic of this research is twofold; first, Generation Expansion Planning (GEP) models in a realistic framework and second, the islanding condition in presence of Renewable Energy Sources (RES).

The traditional structure of electric utility which was vertically integrated has been deregulated in recent years. The replace was a competitive market scheme in many countries around the world. For instance during the last decade, competitions have been emerged in European power industry according to the EU-electricity guidelines. Social welfare maximized in a perfect market and also efficiency of market was the main objective of EU electricity market liberalization fulfilled by creating the EU internal electricity market. In a market which is perfectively competitive, suppliers' pricing and operating decisions do not have significant effects on the market price. However, oligopoly is governing most of European electricity markets than perfect market competition where profits of electric firms can be increased via strategic bidding, or through exercising market power in other words. In this context, the system regulator has to recognize how electric firms could raise the prices and consequently erode the consumer's benefit of liberalization. Ergo, economists have suggested models to represent the electricity market behavior.

Additionally, introduction of the carbon market and the green certificate market under renewable energy obligations is the most recent developments in European electricity industry. As the direct consequence of interactions of electricity markets, emission trading market, green certificate market and fuel markets which increases the complexity, participants in EU electricity markets are confronting new challenges since the electricity industry is one of the major agents of these latest developments which necessitate deployment of new models and adequate tools to cover these new challenges. In this context, developing electricity market models able to simulate the complex interaction of the electricity markets and above mentioned markets becomes an even more prominent challenge.

In addition to the discussed changes in electricity market organization, the EU ETS came into effect in 2005 having significant impacts on electricity industry in Europe that covers several sectors such as power generation as the largest. The carbon "emission allowance" will introduce a price on CO_2 emissions and consequently will change the variable cost for fossil-fuelled power plants in short run which not only affects the future investment decisions in the industry, but also changes the competitive price in the market.

Generation Expansion Planning (hereafter GEP) in oligopolistic markets is discussed incorporating several models but generally they do not take environmental considerations such as CO_2 prices into account. In addition, transmission constraints can affect the GEP considerably. It also has considerable importance to include the transmission network representation in the GEP model. Because the generation expansion may add to or relieve transmission lines congestions and consequently affect the zonal prices. Hence, it is a significant task to develop an oligopolistic GEP model for analyzing generation investment decisions under different CO_2 reduction targets while considering the transmission system constraints.

Regarding the activity for islanding in subtransmission grid, modern power systems are characterized by the increasing penetration of Renewable Energy Sources (RES), that makes their integration a challenging problem. However, as the most significant RES are installed at the HV subtransmission level, they also offer an important opportunity to exploit the possibility of wanted or undesired islanding conditions. Therefore, develop an algorithm to check the possibility of islanding condition by means of renewable generation in a case that the certain region of subtransmission system is disconnected from the main system becomes a crucial task.

1.2 Objective of the Study

The objective of this study is divided into four parts. First is to develop a generation capacity expansion model with CO_2 emission and transmission constraints for analyzing possible impacts of European emission trading system and transmission constraints on the Italian power sector in terms of change in electricity prices, generation mix, investment decisions, profits and CO_2 emissions. Second is to improve the model to incorporate RES power plants expansion to analyze the effect of different incentive plans on RES capacity development. Third is to develop the model to investigate the influence of already installed CCGT power plants on the generation mix. Finally is to develop a mathematical model for possibility to supply the load by any available resources in case of disconnected subtransmission system from the transmission network.

1.3 Methodology

An exhaustive review of applied economical models in electricity industry was performed first to find the fittest approach for GEP model. Three model types of "Optimization Models", "Equilibrium Models", and "Simulation Models" were concluded by [52]. In optimization models, the behavior of only one firm is being considered while in equilibrium and simulation models the behavior of each participant is modeled considering competition among all participants. Most of equilibrium models define market equilibria as a mixed complementary problem (MCP) within the traditional framework of mathematical programming which has important computational advantages. The equilibrium models are different in many ways such as the market mechanisms which are modeled, assumed type of strategic interaction or game, fidelity to the physics of power transmission, and computational methods incorporated.As an alternative to equilibrium models, simulation models are introduced for the cases that the problem being considered is too complex and consequently it is quite impossible to be defined within the formal equilibrium framework. Unfortunately, they impose significant computational load. In our work, the equilibrium approach is selected to model generation expansion planning as modeling the electricity market for long term without considering complex technical constraints and cost structures of power plants.

Based on modeled market mechanisms, in our study the market is represented as power pool (POOLCO type) centralized bidding process which is supervised by the Transmission System Operator (TSO). In such a market, the generating companies compete with each other in serving the load, each one aiming to maximize its profit by strategic bidding in the power pool. It is worth to mention the Italian market has a hybrid structure in which generators are not mandated to submit energy bids in power exchange. They are allowed to sign contracts with qualified merchants and customers.

Several methods based on different factors such as price, quantity and supply functions have been developed recently to model the strategic behavior of participants in the electricity market.

In the Bertrand model, firms try to maximize profit by setting price while competing on price rather than output quantity. When players maximize their profits by maximizing their market share, Bertrand competition occurs. In this approach, any firm can capture the entire market by pricing below other competitors. But, since electricity producers have growing marginal costs and limited installed capacity, Bertrand's assumptions on behaviors seems to be less realistic [11], [51], [29].

In Conjectured Supply Function (CSF) method, the historical data is used to predict the behavior of competitors building price and conjectural values. The drawback of this structure is late adaption to the new changes happening in the market similar to all algorithms based on historical data [20], [49], [7], [77], [79], [13].

A Supply Function Equilibrium (SFE) is more capable of handling real cases. However, all rivals reactions are predefined in this model and it is possible to confront multiple equilibria or even have no solutions at all [61], [41], [62], [64], [9] , [27], [53], [63], [28], [16].

Although the Cournot strategy neglects the supply function of competitors, it still seems to be more flexible than its counterparts and has the adaptation ability to long–term competitions [80].

In our work, the Cournot approach is chosen to represent strategic interaction of firms in the electricity market because this approach is more flexible framework for modeling long-term oligopoistic competition in market than other models [80].

There are few models of electricity markets which consider interactions with tradable permit markets. The modeling of the interaction of pollutant emissions permits markets with electricity markets is reflected in the literature within three major categories:

1. While the prices of pollutant emissions permits are exogenous to the model, their effects on electricity costs are included in production cost curves [31],

2. The model for pollutant emissions market is as perfectively competitive one [56],

3. The pollutant emissions market is modeled as a conjectured price response model [75].

By giving CO_2 emission allowance price exogenous to the model, the first approach is selected in our model in incorporating emissions trading market into electricity market. This selection is made considering the fact that CO_2 prices are determined not only by electricity markets but also by the flexible mechanisms set up within the international and inter-continental tools such as Kyoto protocol including clean development mechanism and joint implementation. The second reason is that electricity markets are determined not only by the Italian electricity market, but also by the different national implementation of electricity markets in all the European Countries involved. Therefore, the strategy chosen is to give the CO_2 price exogenous to the model.

In addition, it is very important to include the transmission network representation in the GEP model. Although, it increases model complexity and imposes serious limitations on finding a solution for equilibrium, the generation expansion may lead to add or relieve congestions in transmission lines and consequently affect the zonal prices. In other words, it can have serious impacts on the GEP.

Few models with generation expansion planning (GEP) take into account environmental considerations such as CO_2 prices in oligopolistic markets. In the proposed models, not only the price of carbon is considered but also it deals with transmission system constraints. Moreover, the proposed models allow us taking into account RES expansion planning and also already installed power plants considering their investment cost. Besides, the scalability of the models for larger systems are considered as they presented to the Italian power sector.

With reference to Islanding in Sub-transmission grids part in chapter 9, the island feasibility function is an innovative concept for subtransmission systems, in the smart grids framework. It was designed to give the possibility to supply load by means of any available regulating resource, in particular RES generation, in case the subtransmission grid is disconnected from the transmission network. The goal of this function is to determine, for a given operating condition and a set of triggering events, with an adequate level of security the control actions that allow a operation of the islanded subtransmission system, thus avoiding as much as possible the load disconnection.

The procedure has been mathematically expressed as a constrained integer programming problem that, in a basic approach, maximizes the load to be supplied after islanding.

This objective function is subject to some constraints relevant to total regulating band depending on total load, up (down) regulating band and additional constraints on the minimum value of regulating up and down bands.

1.4 Achievements and Contributions

The achievement of this research work is twofold; a GEP model for electricity market in a realistic framework for analyzing:

- The impacts of EU ETS and transmission constraints on the firm's investment decision,
- The impacts of different incentive plans on RES expansions,
- The impacts of already installed CCGT power plants -considering their investment costs- on the generation mix.

An islanding in sub-transmission grids for analyzing:

- The possibility of islanding in sub-transmission network while it has been disconnected from the bulk power system.

1.5 Outline of the Thesis

The organization of the thesis are as follows: Chapter 2 provides a review of electricity market models applied to the electricity industry. This followed by overview of the Kyoto Protocol and EU ETS in Chapter 3. Generation capacity expansion model with CO_2 emission and transmission constraints in an oligopolistic market is described in detail in Chapter 4. This followed by a description of electricity market of Italy in Chapter 5. Chapter 6 describes data and assumptions used to simulate GEP in the Italian electricity market. An analysing the impacts of the EU ETS & transmission constraints, different incentive plans on RES expansions and also already installed CCGT power plants on the Italian power sector is presented in Chapter 7. Conclusions from this work and issues that should be tackled in further work are presented in Chapter 8. Finally, model for islanding in sub-transmission grids is presented in chapter 9. The aim of this model is to supply the load by means of renewable generation, even in case the sub-transmission grid is disconnected from the transmission network.

CHAPTER 2

Competitive Electricity Market Models

2.1 Introduction

The traditional vertically integrated system has been deregulated and substituted by liberalized system in many countries worldwide. The main purpose of Electric industry restructuring is to improve social welfare. Because in perfect competitive market, where market players (firms) are not capable to influence on the market price, the social welfare can be maximized.However, electricity market structure is more like to oligopoly than perfect market competition. This is because of [24]:

- There is only a limited number of suppliers (barriers to entry),
- Transmission constraints which separate consumers from effective reach of many generators,
- Transmission losses which discourage consumers from purchasing power from distant suppliers.

likewise, in oligopolistic market, the firms are able to alter the price away from competitive level in a profitable way [68]. On the other hand, the firms are able to exercise the market by:

- Reducing the output or increasing the price of the bid for particular unit,
- Exploiting transmission capacity limits,
- Interaction of pollutant emission permits markets and electricity markets [75].

As a result, the system regulator has to identify how electric firms could drive up the prices and accordingly erode the consumer's benefit of liberalization. On account of, economists have proposed models to represent the electricity market behaviour.

2.2 Types of electricity market models

The modeling of deregulated power system operations has been the subject of a great deal of publications. Here, some earlier reviews are represented in order to make some model attribute based comparisons among main approaches. Such attributes are helpful in understanding the pros and cons of each modeling approach. A detailed survey of the power market modeling literature is provided by [52] in which three main trends of electricity market modeling namely optimization models, equilibrium models, and simulation models are depicted. Different approaches of electricity market modeling are illustrated in Figure 2.1 from a structural point of view.

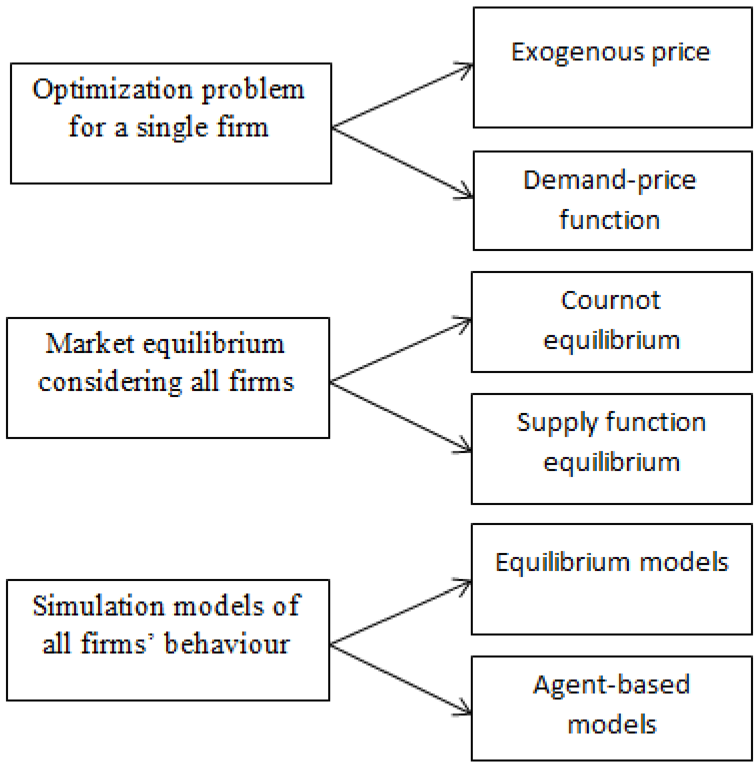

Figure 2.1: *Electricity market modeling approaches.*

2.2.1 Optimization model

The main focus of optimization models is concentrated on profit maximization for one competing firm in the market. In such models, the electricity price is provided exogenously or modeled as a function of the firm's production. Although models with exogenous prices are simple in principle, electricity price prediction in a pool requires analysis combining demand forecasts, participant bidding and transmission congestion as stated by [24]. A time series analysis based price forecasting tool is provided by [38] for competitive electricity markets. The exogenous price models hold the implicit assumption that the market price is not influenced by the bid from one firm that is implausibly valid for oligopoly markets where this method has seldom been applied for developing bidding strategies. Despite the fact that optimization models are not appropriate for potential market power analysis in electricity markets, they are deployed by market participants extensively to develop bidding strategies.

2.2.2 Equilibrium market models

As the most frequently used modeling approach for electricity market analysis in the literature, equilibrium models describe the overall behavior of the market considering competition among all participants in the market [52]. Generally, the market equilibrium is defined as a set of prices, producer input and output decisions, transmission flows, and consumptions that satisfies each market participant's Karushkhun- Tucker (KKT) conditions simultaneously while clearing the market. A review of equilibrium models and also a detailed survey on equilibrium power market models can be found in [30] and [20] respectively. Also, the formulation and application of electricity market equilibrium models in [59] is highly impressive. The general structure of equilibrium models from a mathematical point of view is represented in Figure 2.2. Where π_f represents the profit of each firm f∈{1,...., F}; q_f are firm f's decision variables; and $h_f(q_f)$ represent firm f's constraints; and λ_f and μ_f are dual variables of constraints h_f and g_f respectively.

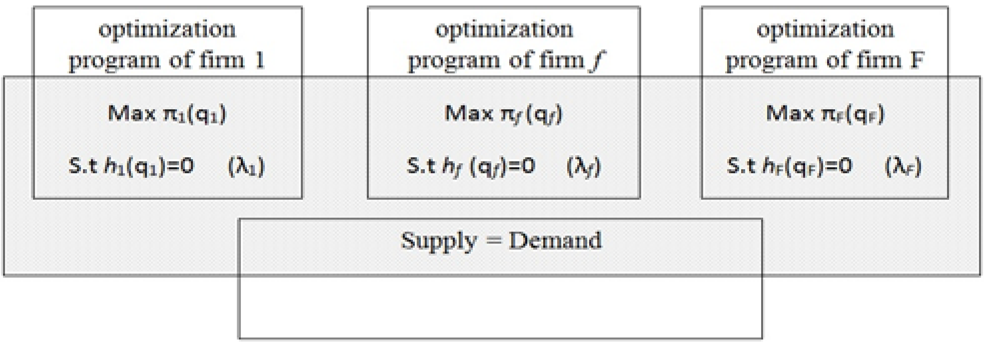

Figure 2.2: *Mathematical structure of equilibrium models.*

Shown in Figure 2.3, the complete set of KKT and market clearing conditions defines a mixed complementary problem (MCP), the direct solution of which has important computational advantages as can be solved by many contemporary algorithms based on advanced nonsmooth Newton methods [50]. It should be notified here that L_f denotes the Lagrangian function of firms f's optimization problem.
The variety of market mechanism models, different types of strategic interactions or games, loyalty to the physics of power transmission, and computational methods used, lead to fully different equilibrium market models. However, convexity of each player's optimization problem is a necessary condition to have a market solution to this type of problems.

2.2.2.1 Market Mechanisms Modeled

The complexity and also behavior of equilibrium models are highly dependent on the mechanism modeled for the market. Although several designs are represented for elec-

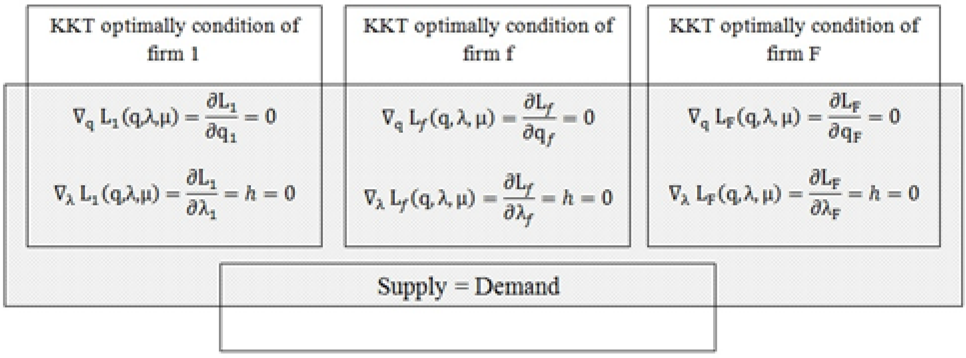

Figure 2.3: *Market equilibrium as a mixed complementary problem.*

tricity market, they all have common features of decentralized competitive bidding in energy and reserves auction markets and also some level of access to transmission and non-discriminatory pricing [42]. The proposed market models vary from highly centralized and controlled POOLCO model to comparatively bilateral and decentralized ones in the literature. There are differences between mechanisms for market clearing and the ones for market structure (centralized/POOLCO or decentralized/bilateral). Addressing a POOLCO and a bilateral market in modeling electricity markets are illustrated in models deployed in [20] and [12]. An equilibrium market model with mixed POOLCO bilateral system is represented at [75]. It is illustrated by [21] that Cournot competition among firms yields the same results for both bilateral model with arbitrage and POOLCO market designs. Also it is demonstrated by [20] that both the POOLCO and bilateral model with arbitrage lead to the same equilibrium price for constant slope conjectured supply function (CSF) model and identical total sales and returns for each firm.

2.2.2.2 Types of Strategic Interactions

The interaction type assumed among rival firms and other players are highly effective on the results of equilibrium market models. Deferent strategies originate from each firm's anticipation of rivals reaction to its decisions about either prices or quantities. Consequently, firms' strategic behaviors could be modeled considering competition of price, quantity or supply function.
Bertrand and Cournot strategies, collusion, Stackelberg, General Conjectural Variations (CVs), supply function equilibria (SFE) and conjectured supply function (CSF) are strategic interactions incorporated in literature on power market modeling most of which are formulated based on some game theory techniques which study strategic interactions between some players. Given the strategies chosen by the other players, each player chooses prices or quantities as strategies in electricity markets as strategic games which will maximize the profit. Explained by the game theory , market equilibrium is each participant's strategy that its one-sided variations would result in less profit for itself [25]. Just as Nash equilibrium, no participant will intend to modify its decision unilaterally at equilibrium as a property of market solution.
The main features of several strategic interactions adopted in electricity market model-

ing are addressed in the following subsections in detail. To describe one firm's behavior under different strategic interactions, the following notations must be defined first: q_f is the sale or output of firm f, p the equilibrium price, p_f the price offered by firm f, q_{-f} the quantity supplied by firms other than f, p_{-f} the vector of price offered by f's rival firms.

2.2.2.2.1 Bertrand Strategy Seeking to maximize profit by setting price, firms compete on price rather than output quantity in the Bertrand model. Having the assumption that firms produce homogeneous products and are able to supply the entire market demand, Bertrand competition is often used in the study of duopolies and occurs when players take market share maximization approach to maximize their profit. The model predicts that the firm with the lowest costs will supply the entire market. Under Bertrand, the price and the number of firms in the market are not related. However, this no longer applies if the firms produce differentiated products or have capacity constrained and increasing marginal costs, so that they are not able to supply the entire market. In case of no limitations and transmission costs, the price will fall to marginal costs and the revenue of firm f with Bertrand strategy will be as follows:

$$pq_f = p_f q_f(p_f, q_f) \tag{2.1}$$

As mentioned before, firm f assumes that rivals' prices stay the same in reaction to f's price and also f's decision variable is p_f. Consequently, f is able to sell as much up to market demand if p_f is less than the lowest delivered price among rival producers. Bertrand's assumptions on firms' behaviors appear far from the reality since electricity producers have increasing marginal costs and limited installed capacity [11]. This is why this approach has not been popular in electricity market modelings. [51] and [29] address the application of Bertrand's approach to electricity markets.

2.2.2.2.2 Cournot Strategy One essential assumption in Cournot model is each firm tends to maximize profits considering its own output decision not effective on the rivals'. Thus in Cournot game, each firm chooses q_f with a known demand curve assuming their rivals' output is fixed. If $p(q)$ is the inverse market demand function, the revenue of firm f can be written as;

$$\begin{aligned} pq_f &= p(q_f, q_{-f})q_f \\ MR = \partial/\partial q_f(pq_f) &= p + q_f(\partial p/\partial q_f) \\ MR &= p + q_f(\partial p/\partial q)(\partial q/\partial q_f) \\ q &= q_f + q_{-f} \\ MR &= p + q_f \partial p/\partial q(1 + \partial q_{-f}/\partial q_f) \end{aligned} \tag{2.2}$$

Having the assumption of fixed supply for rivals in Cournot game by each firm($\partial q_{-f}/\partial q_f = 0$):

$$MR = p + q_f(\partial p/\partial q) = MC \tag{2.3}$$

The optimal quantity level of each firm is obtained by above equation as a function of the other firm's quantity resulting mathematical structure of Cournot models to be a set of algebraic equations easy to compute. The simplicity and ease of computation have made the Coutnot solution a popular concept in power market modeling while one drawback of it is overestimation of observed market price and underestimation of market quantities. As the model outcome is merely based on quantity competition, the results are highly sensitive to demand elasticity assumptions. Cournot models in electricity market are applied to a wide range of applications ranging from market power analysis and influence of transmission networks to hydro thermal coordination. A more general survey on Cournot models utilized to analyze market power problems are represneted in [46]. A numerical model is incorporated to illustrate the quantitative relation between Cournot-equilibrium price, the number of firms, and the size distribution of firms in Swedish electricity market by [10]. Also, Cournot models have been studied in congestion pricing analysis of transmission networks. [72], [67], and [23], have used Cournot completion to model electricity markets by representing electricity network solely by power flow conservation-equations. [76], [12] and [21] propose Cournot models including transmission constraints for realistic networks in which the transmission system is represented as a linearized DC network. [18] discusses the necessity of assumptions to include transmission constraints in Cournot models. Not only the Cournot competition has been used for modeling the gaming by thermal electricity generating firms, but also for mix hydro-thermal firms. [69] utilized Dual Dynamic Programming method to develope medium term market model for mixed hydro-thermal power market of New Zealand in which the medium term hydro optimization problem at each stage is superimposed on Cournot market equilibrium. [45] has proposed a Cournot based modeling framework to analyze the competition between multiple firms possessing a mixture of hydroelectric and thermal generation resources.

2.2.2.2.3 Collusion F and another supplier might maximize their joint profit if collude which makes the cooperative game theory assumption of "transferable utility" meaning that side payments without transaction costs are possible. Other collusive models could be obtained through other assumptions. Collusion has been modelled in [74] as a cooperative Nash bargaining game in which an open access transmission method for maximizing profits in a power system is described. The method proposed is laid on the Nash bargaining game for power flow analysis in which each transaction is determined along with its optimal price to optimize the interests of individual parties which has been used as cooperative limit-pricing as well [15]. While the research has been conducted to deregulate the generation of electric power, unregulated generators would be spatial oligopolists because transmission costs would insulate them from competition from distant producers. Estimating the degree to which unregulated power generators would be able to exercise market power is the major purpose of this study accomplished by calculating spatial price equilibria for a hypothetical deregulated power market in New York state and used also in [22].

A time varying–transition–probability Markov–switching model is incorporated in [37] in order to analysis the time-series of prices in the Spanish electricity market. Accounting for changes in the conditions of cost and demand that reflect changes in input costs, capacity availability and hydro power, it demonstrated that time series of prices are characterized by two substantially different price levels. Incorporating one Cournot model for contracted firms, optimal deviations of firms have been characterized from a collusive agreement and identify trigger variables that could be deployed to discourage deviations.

2.2.2.2.4 Stackelberg A "leader" is assumed in Stackelberg models whose decisions correctly considers the reactions of "followers" that do not recognize how their reactions affect the leader's decisions. For instance, if the firm f is the leader and suppliers other than f are followers, their supply response to p will correctly be anticipated to be $q_{-f}^{True}(p)$. Then, f's revenue can be depicted as follows:

$$p[q_f + q_{-f}^{True}(p)]q_f \tag{2.4}$$

As $q_{-f}^{True}(p)$ results from solving equilibrium conditions, it is often non-smooth. Stackelberg games have other formulations as well. Meanwhile, they have represented interactions between large power producers or "leaders" and one or more "followers" that are smaller generators. While this model has been incorporated to analyse electric transmission pricing policies in the US in [14], a practical and also efficient MPEC–based procedure for calculating oligopolistic price equilibria for an electric power market has been developed and illustrated in [17]. In [26], an algorithm that optimizes the generation dispatch for a dominant firm has been applied to Colorado's electricity market. The results demonstrate that the dominant electricity generation firm can strategically congest the transmission into a region to collect maximum price. In the case that the maximum price is not attainable, the dominant firm still receives an average mark up more than 10% over the competitive price. This model is incorporated to demonstrate how mitigation strategies can decrease prices in a wholesale electricity generation industry by limiting a dominant firm's marker power.

2.2.2.2.5 Supply Function Equilibria (SFE) The interesting features of SFE approach introduced by [55] is the firms compete in price and quantity schedule say supply functions rather than only fixed prices and quantities. Hence, the decision variables of each firm are ϕ_f of its bid function $q_f(p/\phi_f)$ in SFE models, rather than simple price or quantity as in Bertrand and Cournot models. The revenue of firm f can be written as:

$$pq_f = p(q_f(p/\phi_f) + \sum_{-f} q_{-f}(p/\phi_{-f}^*))q_f(p/\phi_f) \tag{2.5}$$

The Asterisk in ϕ_{-f}^* indicates that f treats bid function from other firms as if they are fixed. From the revenue expression above, SFE calculation needs solving a set of differential equations instead of typical set of algebraic equations arising in Cournot and Bertrand models and consequently causes considerable computational challenges concerning their numerical tractability in addition to non-uniqueness and in some cases nonexistence of solutions [52]. However, the equilibria in supply function is shown to be found with restrictive assumptions on the nature of the cost and capacity constraints, the number of firms, or the form of allowed bid functions [61]. Additionally, as it is very difficult to calculate equilibria for large systems, most of SFE studies have been designed for very simple systems like 1-4 nodes [20]. Because of the realistic view of electricity markets by SFE models where functional forms must be specified for demand, cost, and supply functions, they have been widely used in electricity market analysis despite the problems of dealing with equilibria. To tackle this problem in supply function approach, the SFE models reported in the literature have made assumptions on the number of firms and the functional forms of demand, cost and supply functions [41]. For detailed analysis of possible functional forms for demand, cost and supply functions, [62] can be referred. Linear demand functions with non-zero intercept and negative slope independent of time have been used in most of the studies on SFE. Simplest form for marginal cost of firms is the linear marginal cost functions that are affine marginal costs with zero intercept. As the first study on the application of SFE for electricity market analysis, [64] adopted the linear marginal cost function but other studies on SFE have mostly used the affine marginal cost functions (non-zero intercept). Another considerable issue on the cost is different cost functions among firms. Some studies such as [64], [9] , [27] have assumed firms symmetric namely all strategic firms have same cost functions and all have the same capacity limits. Although SFE can be calculated straightforwardly for symmetric producers with general cost functions, but firms in electricity markets are not symmetric. Consequently, most recent studies on SFE have used asymmetric costs and affine marginal cost functions in electricity market modeling. The simplest form of asymmetric problem is when firms have identical cost functions but different capacities. This is utilized by [53] in which firms have identical constant marginal costs but asymmetric capacities showing that there can only be one SFE when demand is inelastic and capacity constraints bind with a positive probability. Stated by [41], the advantage of affine marginal cost function over more general ones SFE models is its ability to deal with asymmetric costs with more than two players. [60] incorporated asymmetric costs and affine marginal cost with unequal intercepts and [64] also tackled the asymmetric duopoly case. [63] has shown the applicability of affine SFE for asymmetric firms with linear marginal costs in analyzing several issues in England and Wales market. Equilibrium behavior of firms has been studied by [28] in the case their costs and their capacities are different proposing a new numerical method to find asymmetric SFE, incorporating piecewise liner approximations and a discretization of the demand distribution. Most of studies on supply function have deployed a form for the supply function which is similar to the assumed inverse marginal cost function form. Despite all the challenges in transmission constraint inclusion in SFE models as it makes models more complex, SFE models with transmission constraints are utilized in literature on small networks. SFE approach adopted by [63] illustrates how the network structure affects the competition in two and four node networks with two electricity producers and consumers incorporating linear demand and affine supply functions. Oligopolistic price equilibria were calculated in [16] for general linearized DC networks using affine supply function with constant slope. A linear asymmetric SFE model with transmission constraints considering forward contracts was proposed by [41] to develop firms' optimal bidding strategies. In [4] the SFE model has been used for evaluating of market power in the Italian electricity market. In this study a coevolutionary genetic algorithm is used to compute the oligopolistic price equilibria of the SFE model.

2.2.2.2.6 General Conjectural Variations (CVs) Some variation into Cournot-based models could be introduced by the CV approach by changing the conjectures that generators may be expected to assume about their strategic decisions of the competitors, in terms of the possibility of future reactions (CV). A firm's conjecture is defined as its belief or speculation of how its rivals will show reaction to the change of its output [79]. Each firm in an oligopolistic market logically maximizes its own benefit considering the reactions of its competitors in conjectural variation model, meaning that each generating firm in general CV model estimates how rival firms regulate their outputs in response to firm's out put(i.e.$q_{-f} = q_{-f}(q_f)$). So, the revenue of firm f can be written as:

$$pq_f = p(q_f + q_{-f}(q_f))q_f \tag{2.6}$$

Firm f's KKT condition to maximize the profit would be:

$$MR = p + q_f \partial p/\partial q(1 + \partial q_{-f}/\partial q_f) \tag{2.7}$$

$$MR = p + q_f \partial p/\partial q(1 + \theta) = MC \tag{2.8}$$

Where θ in the equation is the constant CV.
Implied from the equations above, the CVs attempts to model pricing behavior by generalizing the firms reaction to variations in the other firms' strategic decisions. The fact that firms's CVs may have different values shows different market behavior performed by firms. It is illustrated by Song et al (2003a) that the classic game theory bidding strategies are special cases of CV based bidding strategies and the system equilibrium resulted by CV based bidding strategy is actually a Nash equilibrium. In Cournot, each firm believes that its own output decision will not be effective on its rival's decisions. Therefore, $\theta = 0$ resembles the Cournot game while $\theta = 1$ implies the pure competitive game. If θ represents the actual rivals' local response, this must be called a "consistent conjectures" model. Accordingly, the estimates of CV of generating firms could be utilized in order to analyze the market behavior of firms. As discussed by [20], there have been several critics on CV approach in the industrial economics literature not only due to its static nature often incorporated in an ad-hoc way to dynamic analyzed games, but also because of theoretical difficulties in empirical CV estimation for firms in absence of marginal cost data. However, it is easier to obtained credible cost data for power generation than in other industries. Some researches by [66], [48] and [7] are devoted to CV estimation for firms in electricity markets. [66] proposes an iterative based CV estimation approach able to find parameters fitting the CV based equilibria to historical results and a statistical time-series model that forecasts parameter evolution over time where the proposed fitting procedure has been validated for the Spanish electricity market incorporating historical public market data and marginal cost data of firms which were calculated from detailed methodology based on a cost minimization problem. A theoretical CV estimation frame work using marginal cost data of firms, market clearing price, market share, and price elasticity of demand has been proposed by [48]. An empirical methodology is also proposed based on CV estimates to analyze the dynamic oligopoly behavior of firms which has been used to analyze the Australia National Electricity Market. While, the methodology proposed by [7] is based on residual demand elasticity fitting by evaluation of CVs on the past data say prices, production, and estimation of firms' marginal cost which was validated by a case study applied to Spanish Electricity Market. Another dynamic learning method for generation firms is proposed by [78] to improve their strategic bidding behavior in a spot market and verified using simple duopoly and a six-firm market. In the mentioned method, each firm learns dynamically and regulates its conjecture upon its rival's reflexes to the bidding according

to available information in the electricity market and makes it optimal generation decision based on the updated CV of its rival. Spanish electricity market is modeled by [56] using CV approach as well.

2.2.2.2.7 Conjectured Supply Function (CSF) In this case each generating firm speculates about how rival firms adjust their outputs in response to price changes. Thus, we will have:

$$q_{-f} = q_{-f}(p) \tag{2.9}$$

Consequently, the revenue of firm f could be as follows:

$$pq_f = p(q_f + q_{-f}(p))q_f \tag{2.10}$$

Concerning how total supply from rival firms will react to the price, a CSF is a function representing beliefs of a firm. Two versions of a linear CSF are discussed by [20] in which given either the intercept or the slope of conjectured supply response, the other one must be calculated.

Although the CSF model looks like the SFE method [20], the CSF modeling approach is totally different from the widely used SFE approach for market modeling. Discussed in [49] as the fundamental distinction of the SFE and CSF approaches, the conjectured supply response of competing firms is based on an assumed parameter either slope or intercept in the CSF while the anticipated supply response of competitors is endogenous in SFE models and is consistent with the competitor's actual bid function. This provides SFE with relatively easy to solve MCP formulation, the solutions of which exist and are unique.

Only a few published power market models are proposed based on the CSF approach. Bilateral and POOLCO formulations of CSF models for a power market including transmission constraints are presented in an interesting paper by [20] where the power network was represented with a linearized DC load flow. Also, a linear supply function is constructed near equilibrium point on the basis of the CV concept, and the existence and uniqueness is discussed when either intercepts or slopes of supply function are fixed. CSF is used to simulate the Spanish electricity market by [7] in which the model was based on the quantity competition model with estimated residual demand functions in terms of CSF. To simulate strategic behavior interactions of generating firms in electricity markets with incomplete information, CSF equilibrium based model is presented by [77] where the CSF equilibrium model is formulated directly from the SFE theory considering the CV of each participant about the aggregated response of the rivals to a change in the market clearing price. The CSF based model and classical game theoretic models is also compared by [79]. Concerning how the amount of those services demanded by the generator will affect the transmission service price, CSF model is generalized by [13] to include each generator's conjectures. The NOx emission permit market of Ozone Transport Commission of U.S. is simulated by [75] incorporating a model of conjectured price response. [3] presents CSF model for analyzing the price development in the Italian electricity market under different degrees of competitiveness in the market.

2.2.3 Simulation Models

In cases such as the medium to long-term that the considered problem is too complex to be addressed within a formal equilibrium framework, simulation models are an alternative to equilibrium models where investment decisions, hedging strategies and learning processes become important endogenous variables.
An equilibrium simulation model based on Cournot Nash approach is represented by [65]. A simulation model based on linear Supply function approach and solved incorporating Monte Carlo method is proposed by [40]. The electricity market simulation model in [8] calculated the market equilibrium in each of 13 regions of the National Electricity Reliability Council (NERC) in the United States considering coal and natural gas markets, interregional power trading, the capacity investments, and emissions taxes. In the proposed simulation model by [19], optimal supply functions are constructed in order to analyse the potential market power in the EW Pool. A simple dynamic bidding model was presented by [47] based on the Cournot iterative equilibria concept which has been successfully implemented to obtain optimal bidding strategy of a fictitious generating company in the Spanish electricity market which comprises both hydro and thermal units. A simulation model called COSMEE has been adopted by the [44] to analyse Spanish electricity market which simulates the behaviour of the electricity market based on simple bids. In this model, technical constraints such as maximum and minimum power limits and ramp rates for thermal plants and maximum and minimum power limits and availability of hydro energy for hydro plants, complex cost structures like start-up costs, and bidding strategies are integrated by the market participants in their offers. A simulation model providing an optimal supply function to analyse market power is represented in [19] which provides a more flexible framework to use actual marginal cost data and asymmetric firms in the model as this approach is similar to the SFE.

CHAPTER 3

The Kyoto Protocol and European Union Emissions Trading Scheme

3.1 Introduction

Global warming provokes essential debates among environmentalists, politicians, and industry representatives. Despite the strong consensus in the scientific community on seriousness of the greenhouse effect, and that humans are adding to concentrations of greenhouse gases in the atmosphere, much remains unknown about the long-term consequences of anthropogenic activity on the climate.
The most recent international effort to tackle the greenhouse effect was an agreement among the industrialized nations called Kyoto Protocol to reduce emissions of six greenhouse gases over a certain period of time.
The Protocol developed three innovative mechanisms to give Parties a certain degree of freedom to meet their emission reduction targets known as International Emissions Trading (IET), Joint Implementation (JI) and the Clean Development Mechanism (CDM) [70]. These mechanisms called "market-based mechanisms" allow developed Parties to earn and trade emissions credits through implemented projects either in other developed countries or in developing countries, which they can deploy to meet the commitments.
Started on 1st January 2005, the European Union has established the European Union Emission Trading Scheme (EU ETS) in this framework [32], [35], [33], [34].

3.2 The Kyoto Protocol

The Kyoto Protocol, adopted in Kyoto, Japan on 11 December 1997 and entered into force on 16 February 2005, is an international agreement linked to the United Nations Framework Convention on Climate Change the major feature of which is that it sets binding targets for 37 industrialized countries and the European community for reducing emissions of greenhouse gases (GHG) which amount to an average of 5% against 1990 levels over the five-year period 2008-2012. The essential difference between the Protocol and the Convention is that the Protocol commits the industrialized countries to stabilize GHG emissions while the Convention encourages them to do so. Recognition of the developed countries as the responsible for current high levels of GHG emissions as a result of more than 150 years of industrial activity, the Protocol places more severe responsibilities on developed nations under the principle of "common but differentiated responsibilities". Called the "Marrakesh Accords", the detailed rules for Protocol implementation were adopted at COP 7 in Marrakesh in 2001 [39].

3.2.1 Kyoto Mechanisms

Countries must meet their goals mainly through national measures under the Treaty. However, the Kyoto Protocol offers an additional option for meeting the goals known as three market-based mechanisms as follows.

3.2.1.1 Joint Implementation

Defined in Article 6 of the Kyoto Protocol, the mechanism called "joint implementation" allows a country with an emission reduction or limitation commitment under the Kyoto Protocol to earn emission reduction units (ERUs) from an emission-reduction or emission removal project in another developing country each equivalent to one ton of CO_2. This can be counted as meeting its Kyoto goal as well and offers Parties a flexible and cost-efficient way of fulfilling a part of their Kyoto commitments, while the host Party will be beneficial of foreign investment and technology transfer.

3.2.1.2 Clean Development Mechanism

Defined in Article 12 of the Protocol, the Clean Development Mechanism (CDM) lets a country with an emission-reduction or emission-limitation commitment under the Kyoto Protocol to execute emission-reduction plans in developing countries that can earn saleable certified emission reduction (CER) credits each equal to one tone of CO_2. The mechanism as a pioneer can be assumed as meeting Kyoto goals. Indeed, CDM is the first standardized emissions offset instrument (CERs) as a global environmental investment and credit scheme of its kind. In a CDM project, some activities including rural electrification making use of solar energy, or installing energy-efficient boilers might be involved. Providing industrialized countries enough flexibility in satisfying their emission reduction or limitation commitments, this mechanism stimulates sustainable development and emission reductions.

3.2.1.3 International Emissions Trading

Under the Kyoto Protocol, the parties have accepted limiting or reducing their emissions, including levels of permitted emissions or "assigned amounts", which divided into "assigned amount units" (AAUs), during the 2008-2012 commitment time frame. Expressed in Article 17 of the Kyoto Protocol, countries that have emission units to spare can sell this amount to the other countries that are over their emission limitations. Therefore, there is a new concept named "carbon market", which refers to the new commodity in the form of emission reduction. The principle greenhouse gas is carbon dioxide, and thus people simply talk about carbon trading.

3.3 European Union Emissions Trading Scheme (EU ETS)

The leading efforts to reduce the greenhouse emissions of mankind activity, which is a threat to world's climate, is performed by the European Union. The EU Emissions Trading Scheme (EU ETS) is developed by the European Union as a basis for the plan to cost-effectively and considerably reduce the greenhouse gas emission inside the Union. This scheme has been launched at the beginning of 2005, and is the first international company-level 'cap-and trade' system for allowing the emission of carbon dioxide (CO_2) and other greenhouse gases. This mandatory system is now the generator of any expansion of the international carbon market and is based on the innovative mechanisms set up under the Kyoto Protocol-international emissions trading, the CDM and Joint Implementation JI. In EU ETS, a price is put on each emitted tone of carbon; in this way it runs the investment in low-carbon technologies. In this way, EU ETS forces the emission costs to company boards, arranging the originality and creativity of the business community to look for innovative and cost-effective methods to deal with climate changes. The system has originated new related service providers such as carbon trading, carbon finance, carbon management and carbon auditing. Under the EU ETS, the European Union should be allowed to reach its emission reduction target under the Kyoto Protocol at a cost of below 0.1 % of GDP which is significantly less than would otherwise be the case. The system will also be key to meeting the EU's more ambitious emission reduction targets for 2020 and further into the future.

3.3.1 What the EU ETS covers

The emission trading may include many greenhouse gases and economic sections; however in EU ETS, the emissions which can be measured, reported and verified with good accuracy are considered. During 2005 to 2007, the first trading time interval, the scheme focuses on carbon dioxide emissions from high-emitting industries of power and heat generation and on some energy-intensive industries such as combustion plants, oil refineries, coke ovens, iron and steel plants and factories making bricks, glass, cement, lime, ceramics, pulp and paper.
During 2008 to 2012, the second trading time interval, the scheme also includes nitrous oxide emission from the production of nitric acid. Furthermore, from the beginning of 2008, the EU ETS is geographically extended to cover Iceland, Norway and Liechtenstein. Also, in some cases, based on the production capacity, some individual plants must participate in the system if they are beyond a size threshold. Currently, about 11,000 installations in the EU are included in the system, which is about 50% of overall CO_2 emission of the EU and around 40% of total greenhouse gas emissions.
From 2012, CO_2 emissions of civil aviation will also be included in the EU ETS, which means that all flight from, within or to the EU will require allowances to cover the CO_2 emissions. Use of emissions trading to cope with the emissions from the aviation section is fully in accordance with the International comitments of EU and with the 2004 assembly of the International Civil Aviation Organization decisions.
The coverage of EU ETS will be extended from 2013. It will cover all installations

for capturing, transportation and storage of greenhouse gases, CO_2 emissions from the aluminum, petrochemicals, and ammonia plants, nitrous oxide emissions from the production of nitric, adipic and glyoxylic acid, and perfluoro carbon emissions from aluminum plants. On the other hand, if fiscal or other measures can achieve an equivalent reduction in the emission of small installations, the governments are allowed to exclude them from the EU ETS. Having all these scope changes in the EU ETS, from 2013, the coverage of EU ETS will be extended from about 40% to 43% of total greenhouse emissions of the EU, i.e. the system is expected to have net additional emissions equal to 120-130 per year.

3.3.2 How Does the EU ETS Work?

At the heart of the ETS that operates on a "cap and trade" basis, is the common trading 'currency' of emission allowances one of which represents the right to emit one tone of CO_2 and reductions below the limits (caps) will be tradable. National Allocation Plans (NAPs) prepared by the Member States and approved by the European Commission set out the amount of allowances allocated to each emitter in the scheme that are made public. The scarcity demanded for a trading market to emerge is created by the limit or 'cap' on the total number of allowances allocated in the ETS. Companies keeping their emissions below their allowance limit can sell the excess allowances at a price that is determined by supply and demand at the moment. Those confronting difficulty in remaining within their emissions limit have to adopt one of the strategies of reducing their emissions for instance by investing in more efficient technology or using a less carbon-intensive energy source or buying the extra allowances they need at the market rate whichever is cheapest. This guarantees that emissions are reduced effectively. In the time frame from 2008 to 2012, at least 95% during the initial phase and 90% in the second phase, most allowances are allocated to installations free of charge. As only plants that are covered by the scheme are given allowances, any other individuals, institutions, non-governmental organizations and etc are free to buy and sell in the market in the same way as companies.

3.3.3 Allocation

To be assured of real trading (and also CO_2 emissions are reduced), EU governments must assure that the total amount of issued allowances is less than the amount that would have been emitted under a business-as-usual scenario. The total quantity to be allocated by each Member State at each phase is defined in the Member State National Allocation Plan (NAP). The supervision of the NAP process is conducted by European Commission deciding if the NAP fulfills the 12 criteria set out in the Annex III of the Emission Trading Directive (EC, 2003).

3.3.3.1 Phase I NAPs

During Phase I known as grandfathering, most allowances were given freely in all countries that has been criticized as giving rise to windfall profits, being less efficient than auctioning, and providing poor incentive for novel innovative competition for provision of clean and renewable energy. Consequently, the EU ETS did not establish a robust carbon price and the release of the first verified emissions data resulted in a dramatic collapse of carbon price. The release of the second year's verified emissions data caused the value of an EU allowance (EUA) to drop below half a Euro reflecting the essential weakness of the scheme to date that the cap was not set sufficiently tight to generate a carbon price which incentivizes real emissions reductions and abatement investment.

3.3.3.2 Phase II NAPs

During Phase II (2008-2012), twenty-seven EU Member States proposed 'National Allocations Plans' for distributing allowances to emit CO_2 under the EU ETS during Phase II (2008-2012). But, the national allocation process for Phase II proposed that with excessively generous allocations demanded by many Member States, the mistakes of Phase I would be repeated. Hence, the Commission rejected all allocations requested and proposed a formula to set a maximum level of allowances per Member State that includes levels of emissions reduction effort demanded by Member States under the Kyoto agreement.

3.3.3.3 Post Kyoto

A majority of countries agreed on Doha Climate Summit to extend Kyoto protocol into a second term as it was scheduled to come to an end at late December 2012, which could have terminated the global carbon market mechanisms established to support. This second course of obligations is started on January 1, 2013, and will be completed on December 31, 2020 bridging the gap between the end of the first Kyoto commitment period and the beginning of the next legally binding climate agreement. Although the new treaty is not set to take effect until 2020 at the earliest, the mentioned legal binding agreement will be finished in the Durban Platform track in 2015 ideally.

The second commitment period of the Kyoto Protocol, sets compulsory emissions cuts only on those industrialized countries that have ratified it while the Durban track treaty is universally binding for all nations in the U.N. Climate convention. At this point, only the European Union and a handful of other countries such as Australia, Norway, and Switzerland have sanctioned the second period and others that participated in the first period of the protocol, such as Japan, Russia, Canada, and New Zealand have opted out.

The new agreement grants transfer of excess assigned amount units to the second commitment period over the objection of many such as the Least Developed Countries and the Alliance of Small Island States while the treaty tries to limit their environmental damage. The second term of the protocol warrants that "A country may obtain units up to two percent of its assigned amount for the first commitment period, from other parties' previous period excess reserve accounts into its own". This would limit the amount of "hot air" that can be carried over into the second commitment period of the treaty.

The scheduled conclusion of the Ad Hoc Working Group on Long-term Cooperative Action was also a crucial lynchpin for a successful result in Doha. The Long-term Cooperative Action track as an auxiliary body of the U.N. climate convention was the major result of the 2007 Bali Action Plan. As this track of the negotiations was originally created to last only two years, parties agreed to close it in 2012 during last year's negotiations in Durban.

The Long-term Cooperative Action track assisted the convention's greenhouse gases limiting target in its five-year lifespan by promoting key work plans including:

- Intensifying alleviation efforts to reduce greenhouse gases,
- Generating new work plans on adaptation to changes,
- Policy development to reduce deforestation and degradation emissions,
- Boosting development of clean energy technology and its transfer,
- Raising funds for more action on all of these activities in developing countries.

Both the timing and the substance of the new negotiation track were focused in the new track on the Durban Platform for Enhanced Action. The remarkable conclusion regarding timing was the parties agreed to immediately proceed with substantive discussions meaning that the Durban Platform will be at the heart of the next year's climate negotiations in Poland. Two workstreams were created to address the so-called Ambition Gap and to design the new treaty by 2015. A summary of negotiations comes as follows:

- Although fewer countries signed on, the Kyoto Protocol was reauthorized for another eight years. It now covers only some 12% of global emissions,
- The countries terminated the negotiating track of "Long-term Cooperative Action" started in 2007 which produced the Copenhagen Accords and the Cancun Agreements. The resulted voluntary pollution-reduction obligations were covering 80% of global emissions,
- The new negotiating track on the "Durban Platform for Enhanced Action" took its first steps toward achieving its goals. It was designed last year to produce a new treaty that is applicable to all parties and covers 100% of global emissions by 2015.

The crucial changes for Phase III of the EU ETS include:

- An EU-wide centralized cap decline on emissions annually by 1.74% of the average annual level of the Phase II cap. The course will be from a departure point of the mid-point of Phase II and will describe a declining cap from 2013 onwards. The overall reduction will be 21% below 2005 verified emissions by 2020,
- Adjustments on the EU ETS cap up to the 30% of GHG reduction target when EU ratifies an international climate agreement in the future,
- A substantial increase in auctioning levels. At least 50% of allowances will be auctioned from 2013 compared to around 3% in Phase II. While 100% auctioning will be feasible to the power sector in UK and across most of the EU from 2013, sectors at significant risk of carbon leakage will receive 100% free allocation up to their benchmark,
- 12% of the total allowances auctioned will be re-distributed to Member States which have lower GDP in the interests of solidarity,

- Access to international project credits from outside the EU will be limited to 50% of the reductions demanded in the EU ETS,
- Opt out potential of small emitters and hospitals,
- Aviation inclusion in the EU ETS which was introduced from 2012.

CHAPTER 4

Generation Capacity Expansion Model

4.1 Generation Capacity Expansion Model

4.1.1 Introduction

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.

Furthermore, as an investment in RES is increasing significantly and is highly dependent to the financial incentive system set forth by the government, consequently the role of GEP in a realistic framework to analyze the impact of different incentive plans on RES expansion becomes crucial. Also, in the electricity market there are some power plants which have been installed many years ago but their investment cost have not been recouped yet, to consider this kind of power plants and their role to change the future scenario in terms of generation mix, a GEP model able to consider above mentioned issue becomes prominent challenge.

4.1.2 Approaches used to model GEP in the electricity market

Several models tackle generation expansion planning (GEP) in oligopolistic markets. The Cournot game as an open-loop model extends the Cournot model to include investments in new generation capacities which can be interpreted as describing investments in an oligopolistic market [36]. In such a market, the capacity is simultaneously built and sold in long-term contracts when there is no spot market. For a simplified Finnish electricity market, a dynamic-stochastic Nash-Cournot model has been proposed [58] where the Base and peak load market segments and two groups of production technologies were characterized in a context of stochastic demand growth. The oligopolistic equilibrium in an open loop information structure was computed incorporating two algorithms. To formulate a GEP model that may characterize expansion planning in a competitive framework, particularly in pool-dominated generation supply industries, Cournot model has been used in oligopoly behavior in [6]. To analyze generation investment and market participation decisions of candidate expansion units that vary in costs and forced outage rates, numerical experiments are carried on a test system. Simulations with the computational, game-theoretic, recursive dynamic model developed in [73] imply that the result of perfect competition will be lower prices and the environment is benefited in the form of lower acid and smog emissions. An oligopolistic Generation Expansion Planning model has been presented in [5]. This model is used to analyze the possible long term effects of CO_2 prices that originate from the EU ETS on the Italian electricity market. A model is presented in [54] to investigate the interaction between competition and transmission congestion on power generation expansion, which is modeled as a Cournot competition game. To comply with power flow margins, network transmission constraints are included in the optimal generation expansion problem, and finally, test results from a five-bus power network and the IEEE 24-bus system are presented and discussed. In [71], a two-tier matrix game model has been presented. A novel solution algorithm is developed, that incorporates risk due to volatilities in profit. This solution is intended to be used by generators to make multi-period, multi-player generation capacity expansion decisions. In [57] , the oligopolistic model has been utilized for simulating the growth and operation of the generating firms, which provides some estimation of the influence of the European carbon trading directive in the Spanish electricity market.

Among the reviewed models, only a few of them ([73], [5], [57]) take into account the environmental considerations such as CO_2 prices. However, there is an assumption in most of these models that firms make their GEP decisions based on the Cournot model.

4.2 A GEP Model with CO_2 Emission and Transmission Constraints in an Oligopolistic Market

4.2.1 Introduction

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. There is a number of technical options 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.

As the generation expansion may lead to add or relive 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 proposed model can also be used to analyze the long-term implications of different GHG mitigation policies like emissions trading and carbon tax.

4.2.2 The Model

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. In our study the Cournot game has been used to represent an oligopolistic electricity markets. But, it differs from the classic Cournot model in that it incorporates both CO_2 emission costs, and transmission constraints, through the differentiated nodal prices. The model formulated for GEP has three components: a) generating firms' model, b) TSO model, c) market clearing conditions. The mathematical formulation of model for each of these three components follows by the introductions to notations given below.

4.2.3 Notations

4.2.3.1 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 price of CO_2 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 pump plants of firm f

$MCPM_{fpm}$ Marginal cost of the pm-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_{fpm} bus number the pm-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_{fpmt} Maximum capacity of pumping storage plant pm 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]

4.2.3.2 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_{fpmtb} generation from the pm-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 thermal plant n of firm f

4.2.4 Generating Firms Model

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 (see also figure 4.1):

$$p_{itb} = p^0_{itb} - \epsilon_{itb}(q_{itb} - q^0_{itb}) \tag{4.1}$$

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

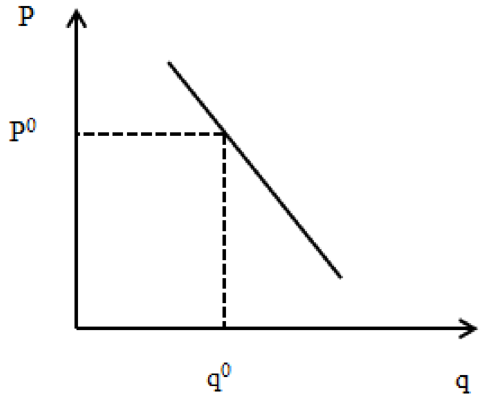

Figure 4.1: *Assumed demand curve*

(SC_f) and salvage (FS_f) are considered.
Among the costs, it is important to take into account the EU ETS mechanism (as it has been explained in chapter 3.3) 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:

1. 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,

2. 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:

$$max\Big[PE_f + PH_f + PPM_f + PC_f + PEN_f - SC_f + FS_f\Big] \tag{4.2}$$

where:

$$
\begin{aligned}
PE_f &= \Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{e=1}^{E_f} B_{tb}(p_{fitb} - MCE_{fe} - Pc_t EE_{fe}) qe_{fetb}\Big] \\
PH_f &= \Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{h=1}^{H_f} B_{tb}(p_{fitb} - MCH_{fh}) qh_{fhtb}\Big] \\
PPM_f &= \Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{pm=1}^{PM_f} B_{tb}(p_{fitb} - MCPM_{fpm}) qpm_{fpmtb}\Big] \\
PC_f &= \Big[\sum_{c=1}^{c_f} \sum_{t=VC_{fc}}^{T} B_{tb} D_t \sum_{b=1}^{LB_t}(p_{fitb} - MCC_{fc} - Pc_t EC_{fc}) qc_{fctb}\Big] \\
PEN_f &= \Big[\sum_{n=1}^{EN_f} \sum_{t=vn_{fn}}^{T} B_{tb} D_t \sum_{b=1}^{LB_t}(p_{fitb} - MCEN_{fn} - Pc_t EE_{fn}) qen_{fntb}\Big] \\
SC_f &= \Big[\sum_{n=1}^{EN_f} D_t CC_{fn} x_{fn} \quad for \quad t = vn_{fn}\Big] \\
FS_f &= \Big[\sum_{n=1}^{EN_f} D_T SV_{fn} x_{fn}\Big]
\end{aligned} \tag{4.3}
$$

In 4.1, 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 4.3, the CO_2 prices emerge from the CO_2 market.
The objective function above is subject to the constraints described in the following.

- 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 (see also figure 4.2):

$$
p_{fitb} = p_{fhtb} + w_{itb} \qquad \forall i \neq h, f, t, b \quad (\mu lmp_{fitb}) \tag{4.4}
$$

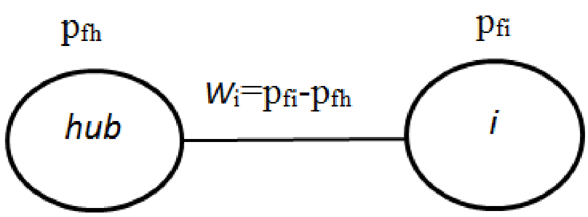

Figure 4.2: *Transmission cost*

As p_{fitb} must also fulfill equation 4.1, replacing q_{itb} in equation 4.1 with the net injection in the node i (see also equation 4.32), gives:

$$\begin{aligned} p_{fitb} = p^0_{itb} - \epsilon_{itb}(\sum_{k=1}^{F}\sum_{e=1}^{E_k} qe_{ketb} + \sum_{k=1}^{F}\sum_{h=1}^{H_k} qh_{khtb} \\ + \sum_{k=1}^{F}\sum_{pm=1}^{PM_k} qpm_{kpmtb} + \sum_{k=1}^{F}\sum_{c=1}^{C_k} qc_{kctb} + \sum_{k=1}^{F}\sum_{n=1}^{EN_k} qn_{kntb} - q^0_{itb}) \end{aligned} \tag{4.5}$$

$$\begin{cases} qc_{kctb} = 0 \;\; for \;\; t < VC_{kc}, \\ qn_{kntb} = 0 \;\; for \;\; t < VN_{kn}. \end{cases} \tag{4.6}$$

According to the Cournot approach, in this study it has been assumed that 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:

$$qe_{fetb} \leq GE_{fet} \quad \forall f, e, t, b \quad (\mu pe_{fetb}) \tag{4.7}$$

$$qh_{fhtb} \leq HF_t GH_{fht} \quad \forall f, h, t, b \quad (\mu ph_{fhtb}) \tag{4.8}$$

$$qpm_{fpmtb} \leq PMF_t GPM_{fpmt} \quad \forall f, pm, t, b \quad (\mu ppm_{fpmtb}) \tag{4.9}$$

$$qc_{fctb} \leq GC_{fct} \quad \forall f, c, t \geq VC_{fc}, b \quad (\mu pc_{fctb}) \tag{4.10}$$

$$qen_{fntb} \leq x_{fn} \quad \forall f, n, t \geq VN_{fn}, b \quad (\mu pn_{fntb}) \tag{4.11}$$

- 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:

$$x_{fn} \leq MAX_{fti} \quad \forall f, n, t \quad (\mu IC_{fnt}) \tag{4.12}$$

- 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 or 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:

$$\sum_{t=1}^{N} B_{tb} a_{fitb} = 0 \quad \forall f, t, b \quad (\mu a_{ftb}) \tag{4.13}$$

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

$$qe_{fetb}, qh_{fhtb}, qpm_{fpmtb}, qc_{fctb}, qen_{fntb}, x_{fn} \geq 0 \tag{4.14}$$

The KKT optimality conditions for firm f:

· For $\quad qe_{fetb}, \quad \forall f, e, i \neq hub, t, b$

$$\begin{aligned} & D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ & - MCE_{fe} - Pc_tEE_{fe}) - \mu pe_{fetb} + \mu lmp_{fitb}\,\epsilon_{itb} \leq 0; qe_{fetb} \geq 0 \end{aligned} \tag{4.15}$$

· For $\quad qe_{fetb}, \quad \forall f, e, i = hub, t, b$

$$\begin{aligned} & D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ & - MCE_{fe} - Pc_tEE_{fe}) - \mu pe_{fetb} - \sum_{i \neq h} \mu lmp_{fitb}\,\epsilon_{itb} \leq 0; qe_{fetb} \geq 0 \end{aligned} \tag{4.16}$$

· For $\quad qh_{fhtb}, \quad \forall f, h, i \neq hub, t, b$

$$\begin{aligned} & D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ & - MCH_{fh}) - \mu ph_{fhtb} + \mu lmp_{fitb}\,\epsilon_{itb} \leq 0; qh_{fhtb} \geq 0 \end{aligned} \tag{4.17}$$

· For $\quad qh_{fhtb}, \quad \forall f, h, i = hub, t, b$

$$\begin{aligned} & D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ & - MCH_{fh}) - \mu ph_{fhtb} - \sum_{i \neq h} \mu lmp_{fitb}\,\epsilon_{itb} \leq 0; qh_{fhtb} \geq 0 \end{aligned} \tag{4.18}$$

· For $\quad qpm_{fpmtb}, \quad \forall f, pm, i \neq hub, t, b$

$$\begin{aligned} & D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ & - MCPM_{fpm}) - \mu ppm_{fpmtb} + \mu lmp_{fitb}\,\epsilon_{itb} \leq 0; qpm_{fptb} \geq 0 \end{aligned} \tag{4.19}$$

· For $\quad qpm_{fpmtb}, \quad \forall f, pm, i = hub, t, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCPM_{fpm}) - \mu ppm_{fpmtb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qpm_{fptb} \geq 0 \tag{4.20}$$

· For $\quad qc_{fctb}, \quad \forall f, c, i \neq hub, t \geq vc, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCC_{fc} Pc_t EC_{fc}) - \mu pc_{fctb} + \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qc_{fctb} \geq 0 \tag{4.21}$$

· For $\quad qc_{fctb}, \quad \forall f, c, i = hub, t \geq vc, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCC_{fc} Pc_t EC_{fc}) - \mu pc_{fctb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qc_{fctb} \geq 0 \tag{4.22}$$

· For $\quad qen_{fntb}, \quad \forall f, n, i \neq hub, t \geq vn, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCEN_{fn} Pc_t EE_{fn}) - \mu pn_{fntb} + \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qen_{fntb} \geq 0 \tag{4.23}$$

· For $\quad qen_{fntb}, \quad \forall\forall f, n, i = hub, t \geq vn, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCEN_{fn} Pc_t EE_{fn}) - \mu pn_{fntb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qen_{fntb} \geq 0 \tag{4.24}$$

· For $\quad x_{fn}, \quad \forall f, n, i, t \geq vn$

$$-(D_{t=vn_{fn}}\, CC_{fn} - D_t\, SV_{fn}) + \mu pn_{fntb} - \mu IC_{fnt} \leq 0; x_{fn} \geq 0 \tag{4.25}$$

· For $\quad a_{fitb}, \quad \forall f, i \neq hub, t, b$

$$-(D_t\, B_{tb}\, \epsilon_{itb}\, Tot - all - gen_{ftb}) + \mu lmp_{fitb}\, \epsilon_{itb} - B_{tb}\, \mu a_{ftb} = 0 \tag{4.26}$$

· For $\quad a_{fitb}, \quad \forall f, i = hub, t, b$

$$-(D_t\, B_{tb}\, \epsilon_{itb}\, Tot - all - gen_{ftb}) - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} - B_{tb}\, \mu a_{ftb} = 0 \tag{4.27}$$

4.2.5 Power Exchange Model

The market model considered in this study is based on a nodal system. This is done by assuming each zone as a node. According to nodal pricing approach, each constrained area has its own electricity price. Due to changes in physical constraints related to change in production and consumption, prices may differ between nodes.

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 equilibria 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 transmission system has been represented as a linearized "DC" network power flow model, e.g. constant "power transfer distribution factors" ($PTDF_{ki}$) describe how many MW of flow occur on a particular transmission interface k in response to an assumed injection of 1 MW at hub node and withdrawal of 1 MW at node i. The DC model's linearity permits usage of the principle of superposition, which simplifies load flow calculations for market models compared to the complete nonlinear AC load flow model. More, this linear property makes the choice of hub node arbitrary.

Hence,the TSO optimization problem is:

$$\sum_{t=1}^{T} \sum_{b=1}^{LB_t} \sum_{i=1}^{N} w_{itb} B_{tb} y_{itb} \tag{4.28}$$

subject to:

$$\sum_{i=1}^{N} PTDF_{ki}\; y_{itb} \leq T_k \qquad \forall k, t, b \qquad (\mu tr_{ktb}) \tag{4.29}$$

The KKT conditions for GME become:

$\cdot$ For $\quad y_{itb}, \quad \forall f, i \neq hub, t, b$

$$B_{tb}\; w_{itb} - \sum_{i=1}^{N} PTDF_{ki}\; \mu tr_{ktb} = 0 \tag{4.30}$$

4.2.6 Market Clearing Conditions

At the equilibrium, the following balance must hold between the transmission services provided by the grid and the services anticipated or demanded by the arbitragers:

$$a_{fitb} = y_{itb} \qquad \forall f, i \neq hub, t, b \tag{4.31}$$

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

$$q_{itb} = \sum_{f=1}^{F} Tot - gen_{fitb} + a_{fitb} \qquad \forall i, t, b \tag{4.32}$$

$$Tot - gen_{fitb} = (\sum_{e=1}^{E_f} qe_{fetb} + \sum_{h=1}^{H_f} qh_{fhtb} + \sum_{pm=1}^{PM_f} qpm_{fpmtb} + \sum_{c=1}^{C_f} qc_{fctb} + \sum_{n=1}^{EN_f} qn_{fntb}) \tag{4.33}$$

Collecting the first order KKT optimality conditions of the different optimization problems (generation firms, TSO) together with market clearing conditions 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 and solved using the MILES solver.

4.3 Improving the GEP Model to Analyze the Impacts of Different Incentive Plans on RES Expansions

4.3.1 Introduction

As a response to a number of global challenges and concerns like climate change and increasing energy demand, investments on RES are increasing significantly these days and the role of mechanisms which are supporting development acceleration of the RES becomes more inevitable. Consequently, countries around the world set forth the terms for providing incentives to encourage the development and deployment of RES to reach their goals. The main objective of RES financial incentives is to create a legal environment which stably promotes the use of renewable sources. Providing fair compensation for the investment costs and ongoing financial support over the whole life of the projects are two main principle bases for this. The need for an appropriate GEP model becomes crucial when analyzing how different incentive plans can affect the renewable expansion notably in the wind and PV segments.

4.3.2 The Model

Unlike the previous model, generation firms of the optimization problem are divided into two categories of strategic firms which are able to drive up the prices, and Price taking firms which are not. Moreover, strategic firms are capable of installing new capacity on onshore and offshore wind power plants in this proposed model, while the price taking firms could invest a new capacity on solar power plants. New sets and variables of this model follow by the introduction to notations below.

4.3.3 Notations

4.3.3.1 Sets and parameters

F number of strategic firms

FP number of price taking firms

$MCEP_{fpep}$ Marginal cost of the ep-th existing thermal plant of firm fp [€/ MWh]

ENP_{fp} number of new solar plants of firm fp

CC_{fpnp} Capital cost of the new solar panel np of firm fp [€/MW]

SV_{fpnp} Salvage value of new solar panel np of firm fp [€/MW]

EW_f number of new onshore wind of firm f

CC_{fw} Capital cost of the new onshore wind turbine w of firm f [€/MW]

SV_{fw} Salvage value of new onshore wind turbine w of firm f [€/MW]

EWO_f number of new offshore wind of firm f

CC_{fwo} Capital cost of the new offshore wind turbine wo of firm f [€/MW]

SV_{fwo} Salvage value of new offshore wind turbine wo of firm f [€/MW]

$IENP_{fpnp}$ bus number the np-th new solar panel of firm fp is connected to

IEW_{fw} bus number the w-th new onshore wind of firm f is connected to

$IEWO_{fwo}$ bus number the wo-th new offshore wind of firm f is connected to

MAX_t Maximum capacity that can be installed by firms during year t [MW]

AFW availability factor of onshore wind turbine

$AFWO$ availability factor of offshore wind turbine

$AFSO$ availability factor of solar panel

4.3.3.2 Variables

qep_{fpeptb} power generated by the ep-th existing thermal plant of firm fp during the load block b of year t [MW]

$qepnp_{fpnptb}$ Power generated by the np-th new solar plant of firm fp during the load block b of year t [MW]

qew_{fwtb} Power generated by the w-th new onshore wind plant of firm f during the load block b of year t [MW]

$qewo_{fwotb}$ Power generated by the wo-th new offshore wind plant of firm f during the load block b of year t [MW]

xp_{fpnp} Installed capacity of new generator np of firm fp [MW]

xw_{fw} Installed capacity of new generator w of firm f [MW]

xwo_{fwo} Installed capacity of new generator wo of firm f [MW]

vnp_{fpnp} Commissioning year of new plant np of firm fp

vw_{fw} Commissioning year of new plant w of firm f

vwo_{fwo} Commissioning year of new plant wo of firm f

4.3.4 Generating Firms Model

4.3.4.1 Optimization problem of strategic firms

In order to analyze how capacity expansion of renewable energy would be change with different incentive plans, the terms for new onshore wind plants (defined by the GEP solution; PEW_f) & new offshore wind plants (defined by the GEP solution; $PEWO_f$) and also their capital costs and savages have been added to the previous maximization problem (see part 4.2.4).

$$\begin{aligned} &max[PE_f + PH_f + PPM_f + PC_f + PEN_f + PEW_f + PEWO_f \\ &- SC_f - SCW_f - SCWO_f + FS_f + FSW_f + FSWO_f] \end{aligned} \tag{4.34}$$

$$\begin{aligned}
PEW_f &= \Big[\sum_{w=1}^{EW_f}\sum_{t=vw_{fw}}^{T} B_{tb}D_t \sum_{b=1}^{LB_t}(p_{fitb} + incentive\ for\ onshore\ wind)qew_{fwtb}\Big] \\
PEWO_f &= \Big[\sum_{wo=1}^{EWO_f}\sum_{t=vwo_{fwo}}^{T} B_{tb}D_t \sum_{b=1}^{LB_t}(p_{fitb} + incentive\ for\ offshore\ wind)qewo_{fwotb}\Big] \\
SCW_f &= \Big[\sum_{w=1}^{EW_f} D_t CC_{fw} x_{fw} \quad for \quad t = vw_{fw}\Big] \\
FSW_f &= \Big[\sum_{w=1}^{EW_f} D_T SV_{fw} x_{fw}\Big] \\
SCWO_f &= \Big[\sum_{wo=1}^{EWO_f} D_t CC_{fwo} x_{fwo} \quad for \quad t = vwo_{fwo}\Big] \\
FSWO_f &= \Big[\sum_{wo=1}^{EWO_f} D_T SV_{fwo} x_{fwo}\Big]
\end{aligned} \tag{4.35}$$

The terms above is subjected to the previous constraints (part 4.2.4) and also some new constraints as follows:

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

$$qew_{fwtb} \leq AFW\ x_{fw} \quad \forall f, w, t \geq vw_{fw}, b \quad (\mu pw_{fwtb}) \tag{4.36}$$

$$qewo_{fwotb} \leq AFWO\ x_{fwo} \quad \forall f, wo, t \geq vwo_{fwo}, b \quad (\mu pwo_{fwotb}) \tag{4.37}$$

- 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:

$$x_{fw} \leq MAX_{fti} \quad \forall f, w, t \quad (\mu ICW_{fwt}) \tag{4.38}$$

$$x_{fwo} \leq MAX_{fti} \quad \forall f, wo, t \quad (\mu ICWO_{fwot}) \tag{4.39}$$

- Maximum installed capacity limits of onshore and offshore wind plants in each year in advance
  The total new capacity installed of the new onshore and offshore wind plants in each year ahead can not be exceed than assumed threshold value:

$$\sum_{f=1}^{EF} \sum_{w=1}^{EW_f} x_{fw} \leq MAX_t \quad \forall f, w, t \quad (\mu w_t) \tag{4.40}$$

$$\sum_{f=1}^{EF} \sum_{wo=1}^{EWO_f} x_{fwo} \leq MAX_t \quad \forall f, wo, t \quad (\mu wo_t) \tag{4.41}$$

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

$$qew_{fwtb}, x_{fw}, qewo_{fwotb}, x_{fwo} \geq 0 \tag{4.42}$$

The KKT optimality conditions for strategic firm f:

· For $\quad qew_{fwtb}, \quad \forall f, w, i \neq hub, t \geq vw, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ + incentive\ for\ onshore\ wind) - \mu pw_{fwtb} + \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qew_{fwtb} \geq 0 \tag{4.43}$$

· For $\quad qew_{fwtb}, \quad \forall f, w, i = hub, t \geq vw, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ + incentive\ for\ onshore\ wind) - \mu pw_{fwtb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qew_{fwtb} \geq 0 \tag{4.44}$$

· For $\quad qewo_{fwotb}, \quad \forall\forall f, wo, i \neq hub, t \geq vwo, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ + incentive\ for\ offshore\ wind) - \mu pwo_{fwotb} + \mu lmp_{fitb}\, \epsilon_{itb} \leq 0; qewo_{fwotb} \geq 0 \tag{4.45}$$

· For $\quad qewo_{fwotb}, \quad \forall\forall f, wo, i = hub, t \geq vwo, b$

$$D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\ + incentive\ for\ offshore\ wind) - \mu pwo_{fwotb} - \sum_{i \neq h} \mu lmp_{fitb}\ \epsilon_{itb} \leq 0; qewo_{fwotb} \geq 0 \tag{4.46}$$

· For $\quad xw_{fw}, \quad \forall f, w, i, t \geq vw$

$$-(D_{t=vw_{fw}}\ CC_{fw} - D_t\ SV_{fw}) + \sum_{t=vw_{fw}}^{T} \sum_{b=1}^{LB_t} \mu pw_{fwtb}\ \ AFW \\ - \mu ICW_{fwt} \leq 0; xw_{fw} \geq 0 \tag{4.47}$$

· For $\quad xwo_{fwo}, \quad \forall f, wo, i, t \geq vwo$

$$-(D_{t=vwo_{fwo}}\ CC_{fwo} - D_t\ SV_{fwo}) + \sum_{t=vwo_{fwo}}^{T} \sum_{b=1}^{LB_t} \mu pwo_{fwotb}\ \ AFWO \\ - \mu ICWO_{fwot} \leq 0; xwo_{fwo} \geq 0 \tag{4.48}$$

4.3.4.2 Optimization problem of price taking firms

The optimization problem of price taking firms consist of terms for existing plants (defined by the GEP solution; PE_{fp}) & new solar plants (defined by the GEP solution; PEN_{fp}) and also capital costs (SC_{fp}) and salvage (FS_{fp}) of the new solar plants.

So, it becomes (in this case it has been considered that the price taking firms are able to invest in solar power plant):

$$max\Big[PE_{fp} + PEN_{fp} - SC_{fp} + FS_{fp}\Big] \tag{4.49}$$

where:

$$PE_{fp} = \Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{ep=1}^{EP_{fp}} B_{tb}(p^\star_i - MCEP_{fpep} - Pc_t EEP_{fpep}) qep_{fpeptb}\Big] \\ PEN_{fp} = \Big[\sum_{np=1}^{ENP_{fp}} \sum_{t=vnp_{fpnp}}^{T} B_{tb} D_t \sum_{b=1}^{LB_t} (p^\star_i + incentive\ for\ solar) qepnp_{fpnptb}\Big] \\ SC_{fp} = \Big[\sum_{np=1}^{ENP_{fp}} D_t CC_{fpnp} xp_{fpnp} \quad for \quad t = vnp_{fpnp}\Big] \\ FS_{fp} = \Big[\sum_{np=1}^{ENP_{fp}} D_T SV_{fpnp} xp_{fpnp}\Big] \tag{4.50}$$

Where $p_i^\star$ is the price at node i [€/MWh]. Each price taking supplier treats $p_i^\star$ as fixed (or exogenous) to its optimization problem. Because, they believe that they have no market power. For this reason, we put an asterisk * on the variable. The objective function in 4.49 is subject to following constraints:

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

$$qep_{fpeptb} \leq GEP_{fpept} \quad \forall fp, ep, t, b \quad (\mu pep_{fpeptb}) \tag{4.51}$$

$$qepnp_{fpnptb} \leq AFSO \;\; xp_{fpnp} \quad \forall fp, np, t \geq vnp_{fpnp}, b \quad (\mu pnp_{fpnptb}) \tag{4.52}$$

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

$$xp_{fpnp} \leq MAX_{fpti} \quad \forall fp, np, t \quad (\mu ICP_{fpnpt}) \tag{4.53}$$

- Maximum installed capacity limits in each year in advance
  The total new capacity installed of the new plant np can not be exceed than assumed threshold value:

$$\sum_{fp=1}^{EFP} \sum_{np=1}^{ENP_{fp}} xp_{fpnp} \leq IX_t \quad \forall t \quad (\mu IX_t) \tag{4.54}$$

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

$$qep_{fpeptb}, qepnp_{fpnptb}, xp_{fpnp} \geq 0 \tag{4.55}$$

The KKT optimality conditions for firm fp:

· For $\quad qep_{fpeptb}, \quad \forall fp, ep, i, t, b$

$$D_t B_{tb}(p_i^\star - MCEP_{fpep} - Pc_t EEP_{fpep}) - \mu pep_{fpeptb} \leq 0; qep_{fpeptb} \geq 0 \tag{4.56}$$

· For $\quad qepnp_{fpnptb}, \quad \forall fp, np, i, t \geq vnp, b$

$$D_t B_{tb}(p_i^\star + incentive \;\; for \;\; solar) - \mu pnp_{fpnptb} \leq 0; qepnp_{fpnptb} \geq 0 \tag{4.57}$$

· For $\quad xp_{fpnp}, \quad \forall fp, np, i, t \geq vnp$

$$-\left(D_{t=vn_{fn}}\, CC_{fpnp} - D_t\, SV_{fpnp}\right) + \sum_{t=vnp_{fpnp}}^{T} \sum_{b=1}^{LB_t} \mu pn_{fntb}\;\; AFSO - \mu ICP_{fpnpt}$$
$$-\,\mu IX_t \leq 0; xp_{fpnp} \geq 0 \tag{4.58}$$

4.3.5 Power Exchange Model

It is exactly the same as part 4.2.5.

4.3.6 Market Clearing Conditions

At the equilibrium, the following balance must be hold:

$$a_{fitb} = y_{itb} \quad \forall f, i \neq hub, t, b \tag{4.59}$$

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

$$q_{itb} = \sum_{f=1}^{F} Tot - gen_{fitb} + \sum_{fp=1}^{FP} Tot - gen_{fpitb} + a_{fitb} \quad \forall i, t, b \tag{4.60}$$

$$\begin{aligned} Tot - gen_{fitb} = (&\sum_{e=1}^{E_f} qe_{fetb} + \sum_{h=1}^{H_f} qh_{fhtb} + \sum_{pm=1}^{PM_f} qpm_{fpmtb} \\ &+ \sum_{c=1}^{C_f} qc_{fctb} + \sum_{n=1}^{EN_f} qn_{fntb} + \sum_{w=1}^{EW_f} qew_{fwtb} + \sum_{wo=1}^{EWO_f} qewo_{fwotb}) \end{aligned} \tag{4.61}$$

$$Tot - gen_{fpitb} = (\sum_{ep=1}^{EP_{fp}} qep_{fpeptb} + \sum_{np=1}^{ENP_{fp}} qnp_{fpnptb}) \tag{4.62}$$

The equilibrium problem can now be defined as a Linear Complementarity Problem by collecting the previous and new KKT conditions of strategic firms (equation 4.15 – equation 4.27) & (equation 4.43 – equation 4.85) and also price taking firms by using (equation 4.56 – equation 4.58) with grid owner's KKT conditions (equation 4.30) together with the market clearing conditions (equation 4.59 – equation 4.62).

4.4 A GEP Model to Analyze the Impacts of Already Installed Power Plants-Considering their investment costs- on the Generation Mix

4.4.1 Introduction

In the electricity market there are some power plants that have been installed many years ago but their investment costs have not been recouped yet. Recovering the investment cost of these power plants in the long run which not only affects the generation mix, but also changes the future investment decisions. In this context, developing GEP models able to consider above mentioned issue becomes prominent challenge.

4.4.2 The Model

CCGT power plants which have been installed many years ago but their investment costs have not been recouped yet are considered in this model. Belonging to strategic firms, they have been excluded from the set of existing power plants forming a separate set. Also, a new nonlinear constraint is introduced for these power plants as total profit of them should be more than part of their investment costs. New sets and variables of this model follow by the introduction to the notations given below.

4.4.3 Notations

4.4.3.1 Sets and parameters

EC_f number of existing CCGT plants of firm f

EEC_{fec} Emission factor of the existing ec-th CCGT plants of firm f [tCO_2/MWh]

IEC_{fec} bus number the ec-th existing CCGT plants of firm f is connected to

GEC_{fet} Maximum capacity of CCGT plant ec of firm f in year t [MW]

4.4.3.2 Variables

qec_{fectb} power generated by the ec-th existing CCGT plants of firm f during the load block b of year t [MW]

4.4.4 Generating Firms Model

In order to analyze the impacts of already installed CCGT power plants -considering their investment costs- on the generation mix, the term below has been added to the previous maximization problem of strategic firms in subsection 4.3.4.1.

$$PEC_f = \Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{ec=1}^{EC_f} B_{tb}(p_{fitb} - MCEC_{fec} - Pc_t EEC_{fec}) qec_{fectb} \Big] \quad (4.63)$$

The term above is subjected to some new constraints:

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

$$qec_{fectb} \leq GEC_{fect} \quad \forall f, ec, t, b \quad (\mu pec_{fectb}) \quad (4.64)$$

- Constraint to cover the investment cost
  Total profit of CCGT power plants which have been installed many years ago should be higher than part of their investment cost:

$$\Big[\sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}(p_{fitb} - MCEC_{fec} - Pc_t EEC_{fec}) qec_{fectb}\Big] \geq C \quad \forall f, ec \quad (\lambda_{fec}) \tag{4.65}$$

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

$$qec_{fectb} \geq 0 \tag{4.66}$$

Hence, the KKT optimality conditions for firm f become:

· For $\quad qec_{fectb}, \quad \forall f, ec, i \neq hub, t, b$

$$\begin{aligned} &D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\ &- MCE_{fe} - Pc_t EE_{fe}) - \mu pe_{fetb} + \mu lmp_{fitb}\, \epsilon_{itb} \\ &+ \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}(p_{fitb} - MCEC_{fec} - Pc_t EEC_{fec}) \leq 0; qec_{fectb} \geq 0 \end{aligned} \tag{4.67}$$

· For $\quad qec_{fectb}, \quad \forall f, ec, i = hub, t, b$

$$\begin{aligned} &D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\ &- MCE_{fe} - Pc_t EE_{fe}) - \mu pe_{fetb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\ &+ \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}(p_{fitb} - MCEC_{fec} - Pc_t EEC_{fec}) \leq 0; qec_{fectb} \geq 0 \end{aligned} \tag{4.68}$$

· For $\quad qe_{fetb}, \quad \forall f, e, i \neq hub, t, b$

$$\begin{aligned} &D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\ &- MCE_{fe} - Pc_t EE_{fe}) - \mu pe_{fetb} + \mu lmp_{fitb}\, \epsilon_{itb} \\ &- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qe_{fetb} \geq 0 \end{aligned} \tag{4.69}$$

· For $\quad qe_{fetb}, \quad \forall f, e, i = hub, t, b$

$$D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCE_{fe} - Pc_tEE_{fe}) - \mu pe_{fetb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb}$$
$$- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qe_{fetb} \geq 0 \tag{4.70}$$

· For $\quad qh_{fhtb}, \quad \forall f, h, i \neq hub, t, b$

$$D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCH_{fh}) - \mu ph_{fhtb} + \mu lmp_{fitb}\, \epsilon_{itb}$$
$$- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qh_{fhtb} \geq 0 \tag{4.71}$$

· For $\quad qh_{fhtb}, \quad \forall f, h, i = hub, t, b$

$$D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCH_{fh}) - \mu ph_{fhtb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb}$$
$$- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qh_{fhtb} \geq 0 \tag{4.72}$$

· For $\quad qpm_{fpmtb}, \quad \forall f, pm, i \neq hub, t, b$

$$D_tB_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb})$$
$$- MCPM_{fpm}) - \mu ppm_{fpmtb} + \mu lmp_{fitb}\, \epsilon_{itb}$$
$$- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qpm_{fptb} \geq 0 \tag{4.73}$$

· For $\quad qpm_{fpmtb}, \quad \forall f, pm, i = hub, t, b$

$$
\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&- MCPM_{fpm}) - \mu ppm_{fpmtb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qpm_{fptb} \geq 0
\end{aligned}
\tag{4.74}
$$

· For $\quad qc_{fctb}, \quad \forall f, c, i \neq hub, t \geq vc, b$

$$
\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&- MCC_{fc} Pc_t EC_{fc}) - \mu pc_{fctb} + \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qc_{fctb} \geq 0
\end{aligned}
\tag{4.75}
$$

· For $\quad qc_{fctb}, \quad \forall f, c, i = hub, t \geq vc, b$

$$
\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&- MCC_{fc} Pc_t EC_{fc}) - \mu pc_{fctb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qc_{fctb} \geq 0
\end{aligned}
\tag{4.76}
$$

· For $\quad qen_{fntb}, \quad \forall f, n, i \neq hub, t \geq vn, b$

$$
\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot-gen_{fitb} + Tot-gen-frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&- MCEN_{fn} Pc_t EE_{fn}) - \mu pn_{fntb} + \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qen_{fntb} \geq 0
\end{aligned}
\tag{4.77}
$$

· For $\quad qen_{fntb}, \quad \forall f, n, i = hub, t \geq vn, b$

$$\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&- MCEN_{fn} Pc_t EE_{fn}) - \mu pn_{fntb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qen_{fntb} \geq 0
\end{aligned} \tag{4.78}$$

· For $\quad qew_{fwtb}, \quad \forall f, w, i \neq hub, t \geq vw, b$

$$\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&+ incentive\ for\ onshore\ wind) - \mu pw_{fwtb} + \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qew_{fwtb} \geq 0
\end{aligned} \tag{4.79}$$

· For $\quad qew_{fwtb}, \quad \forall f, w, i = hub, t \geq vw, b$

$$\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&+ incentive\ for\ onshore\ wind) - \mu pw_{fwtb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qew_{fwtb} \geq 0
\end{aligned} \tag{4.80}$$

· For $\quad qewo_{fwotb}, \quad \forall f, wo, i \neq hub, t \geq vwo, b$

$$\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&+ incentive\ for\ offshore\ wind) - \mu pwo_{fwotb} + \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qewo_{fwotb} \geq 0
\end{aligned} \tag{4.81}$$

· For $\quad qewo_{fwotb}, \quad \forall f, wo, i = hub, t \geq vwo, b$

$$\begin{aligned}
&D_t B_{tb}(p^0_{itb} - \epsilon_{itb}(2Tot - gen_{fitb} + Tot - gen - frival_{fitb} + a_{fitb} - q^0_{itb}) \\
&+ incentive\ for\ offshore\ wind) - \mu pwo_{fwotb} - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} \\
&- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}\, \epsilon_{itb}\, qec_{fectb} \leq 0; qewo_{fwotb} \geq 0
\end{aligned} \tag{4.82}$$

· For $\quad x_{fn}, \quad \forall f, n, i, t \geq vn$

$$- (D_{t=vn_{fn}}\, CC_{fn} - D_t\, SV_{fn}) + \mu pn_{fntb} - \mu IC_{fnt} \leq 0; x_{fn} \geq 0 \tag{4.83}$$

· For $\quad xw_{fw}, \quad \forall f, w, i, t \geq vw$

$$\begin{aligned} &- (D_{t=vw_{fw}}\, CC_{fw} - D_t\, SV_{fw}) + \sum_{t=vw_{fw}}^{T} \sum_{b=1}^{LB_t} \mu pw_{fwtb}\ \ AFW \\ &- \mu ICW_{fwt} \leq 0; xw_{fw} \geq 0 \end{aligned} \tag{4.84}$$

· For $\quad xwo_{fwo}, \quad \forall f, wo, i, t \geq vwo$

$$\begin{aligned} &- (D_{t=vwo_{fwo}}\, CC_{fwo} - D_t\, SV_{fwo}) + \sum_{t=vwo_{fwo}}^{T} \sum_{b=1}^{LB_t} \mu pwo_{fwotb}\ \ AFWO \\ &- \mu ICWO_{fwot} \leq 0; xwo_{fwo} \geq 0 \end{aligned} \tag{4.85}$$

· For $\quad a_{fitb}, \quad \forall f, i \neq hub, t, b$

$$\begin{aligned} &- (D_t\, B_{tb}\, \epsilon_{itb}\, Tot - all - gen_{ftb}) + \mu lmp_{fitb}\, \epsilon_{itb} - B_{tb}\, \mu a_{ftb} \\ &- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t}\ B_{tb}\, \epsilon_{itb}\, qec_{fectb} = 0 \end{aligned} \tag{4.86}$$

· For $\quad a_{fitb}, \quad \forall f, i = hub, t, b$

$$\begin{aligned} &- (D_t\, B_{tb}\, \epsilon_{itb}\, Tot - all - gen_{ftb}) - \sum_{i \neq h} \mu lmp_{fitb}\, \epsilon_{itb} - B_{tb}\, \mu a_{ftb} \\ &- \lambda_{fec} \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t}\ B_{tb}\, \epsilon_{itb}\, qec_{fectb} = 0 \end{aligned} \tag{4.87}$$

The equilibrium problem can now be defined as a None–Linear Complementarity Problem by collecting new KKT conditions of strategic firms by using equations (4.67 – 4.87) and also price taking firms by using(4.56 – 4.58) with grid owner's KKT conditions(4.30) together with the market clearing conditions(4.59 – 4.62).

4.5 summary

This chapter consists of three major parts. In the first part, the GEP model with CO_2 emission and transmission constraints in an oligopolistic market is discussed. Afterwards, a GEP model which is able to analyze the impacts of different incentive plans on RES expansions is proposed. Finally in the last part, a GEP model is addressed that is able to analyze the effects of already installed power plants on the generation mix considering their investment costs.

CHAPTER 5

The Italian Electricity Market

5.1 Overview of Italian Electricity Sector

Fossil fuels are the main source of electric power production in Italy, which is a specific situation in Italy compared to the rest of European countries: in most of them the main source of electricity production is nuclear and coal power and renewable energies [43]. In 2011, the total electricity production in Italy was approximately 291.5 TWh which was composed of 74.96% from thermal power plants, 16.36% from hydro power plants and 8.68% from other RES [2]. Also, there are electricity imports for the case of supply shortfalls in the country which are mostly imported from Switzerland, France, and Slovenia. Since 1988, the nuclear power sources have been banned in Italy (unlike some other European countries like France and Sweden). As a result of this ban and also lack of any significant competition, the electricity prices are high in Italy.

5.2 Electricity Sector Organization

The deregulation of power system in Italy has gradually performed, which is brought into rule in Europe by the Directive 96/92/EC [1] and in Italy by the new "Electric Law", named the Bersani Decree 79/99 of 31 /3/1999. Three major remedies are suggested in Bersani Decree to promote the competition:

- New power plants are constructed faster,
- From 1 January 2003, every company must respect to have a maximum market share of 50% of all power generated or imported to Italy, directly or indirectly,
- Power imports from neighboring countries are liberalized.

Although, more than 50% of the market share is captured by competing power generation companies, ENEL still significantly controls the electricity generation. Therefore, as established in decree n. 79/99, there are clear evidences of oligopoly control in power generation in Italy. In April 2004, after a three year delay, the Italian power exchange (IPEX) was finally launched. More fluid management of electricity demand and supply and a measure of transparency are provided in the IPEX. The previous liberalized market had the lack of these considerations: it was entirely based on bilateral contracts and administered balancing mechanism.
Since ENEL has large share of mid-merit plants, hydropower and peak plants and also it is practically exclusive pumping storage company. These factors give ENEL the power to be able to set the price in large areas of internal market of the zonal market [2]. So, Italy's energy sector regulator, l'Autorita per l'energia elettrica e il gas (AEEG) introduced close monitoring procedures to keep the market changes under control, because of the latest increased price distortions in the market. The power prices in Italy have had a declining trend, although they are still much higher than the other European exchanges.

5.3 The Italian Power Exchange

The system of the Italian electricity market (IPEX) is organized as a Pool. It is managed by a market operator (Gestore del Mercato, GME). GME is responsible for collecting bids, specifying the merit order for electricity dispatching, and for all subsidiary services. The electricity Pool was initially scheduled to come into effect in January 2001, but practically it started its operations, as a one-side market, at the end of March 2004. The responsibility for guaranteeing the supply of electricity to a group of pre-occupied customers was on a single buyer that was founded in 1999. In January 2005, demand-side bidding system was introduced. Eligible buyers and wholesalers of electricity are able to have bilateral contracts for the power exchange with power generators, because the IPEX is not mandatory. The Electricity Market consists of the Spot Electricity Market (MPE), of the Platform for physical delivery of financial contracts concluded on IDEX (CDE) and of the Forward Electricity Market (MTE).

5.3.1 The Spot Electricity Market

The Spot Electricity Market in turn is consisted of:

- MGP (Mercato del Giorno Prima): Day – Ahead Market
- MI (Mercato Infragiornaliero): Intra – Day Market
- MSD (Mercato dei Servizi di Dispacciamento): Ancillary Services Market

In the hosting of a large part of power sale and buy is performed in the MGP (see figure 5.1). The criterion of economic merit order controls the acceptance of offers and bids. In this criterion the transmission capacity limitations, using a power transmission system zonal model, are considered. The seller bids are valued at the marginal clearing price of their belonging zone. On the other hand, the accepted demand bids are valued at the "Prezzo Unico Nazionale" (PUN - national single price), which, indeed, averages the prices of geographical zones, weighted respect to the power quantities purchased in those zones. Figures 5.2 and 5.3 illustrate the zonal price algorithm and variation of PUN over year 2012 respectively.

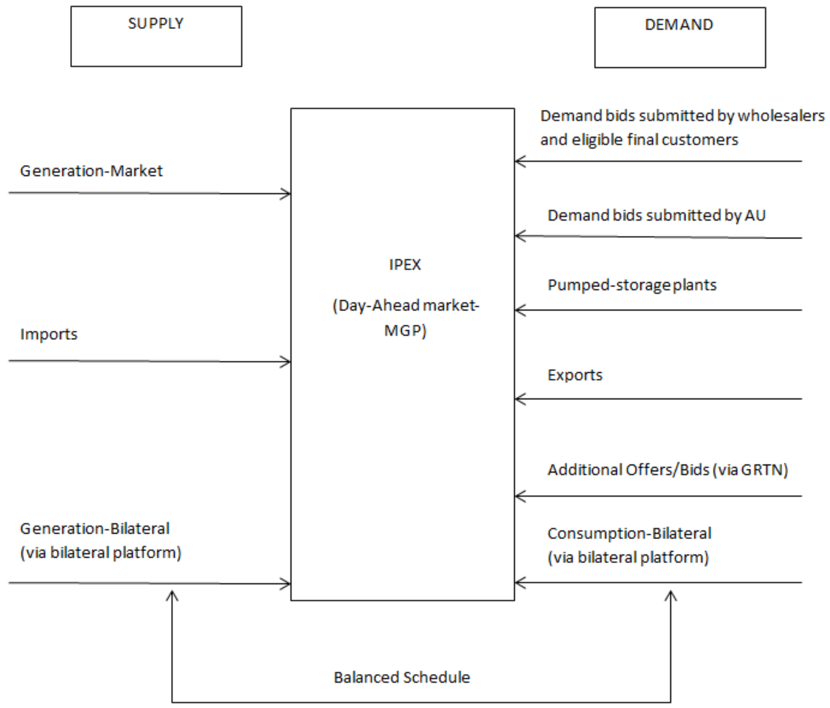

Figure 5.1: *Day-Ahead Market in IPEX*

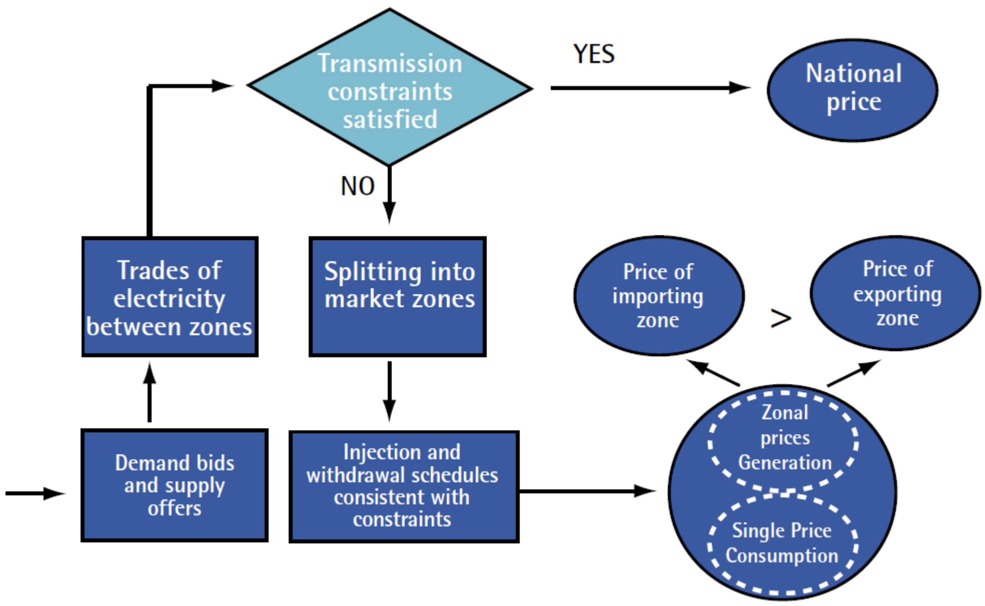

Figure 5.2: *Zonal price algorithm with single price for consumers*

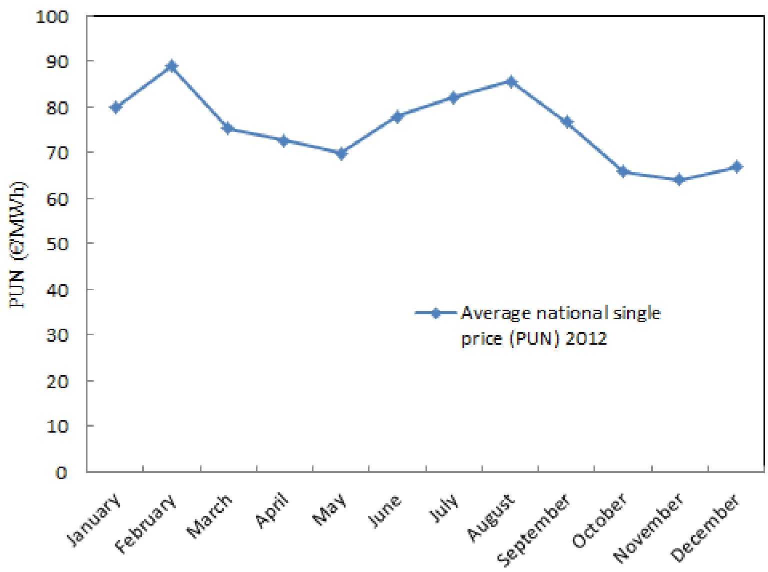

Figure 5.3: *Average National Single Price PUN (€/MWh)*

Under MI, the Market Participants are allowed to submit additional supply offers or demand bids to modify the schedules which are resulted from the MGP. The MI takes place in four sessions: MI1, MI2, MI3 and MI4.

- The sitting of the MI1 takes place after the closing of the MGP. It opens at 10:45 a.m. of the day before the day of delivery and closes at 12:30 p.m. of the same day. The results of the MI1 are made known within 1:00 p.m. of the day before the day of delivery.
- The sitting of the MI2 opens at 10:45 a.m. of the day before the day of delivery and closes at 2:40 p.m. of the same day. The results of the MI2 are made known within 3:10 p.m. of the day before the day of delivery.
- The sitting of the MI3 opens at 4:00 p.m. of the day before the day of delivery and closes at 7:30 a.m. of the day of delivery. The results of the MI3 are made known within 8:00 a.m. of the day of closing of the sitting.
- The sitting of the MI4 opens at 4:00 p.m. of the day before the day of delivery and closes at 11:45 a.m. of the day of delivery. The results of the MI4 are made known within 12:15 p.m. of the day of closing of the sitting.

The criterion to select the offer and demand bids in MI market is the same as the criterion in MGP, except for the accepted demand bids, which are valued at the zonal price.

In the MSD, the necessary resources to guarantee the proper level of power system security are purchased by the Italian Transmission System Operator (Tema S.p.A.). This means that, Terna operates as the principal counterparty in the MSD, and accepted offers/bids are valued at the offered price (pay-as-bid). The MSD is consisted of ex-ante MSD (a scheduling stage) and the Balancing Market (MB).

5.3.2 The Platform for physical delivery of concluded financial contracts

Financial electricity derivatives are traded in IDEX which is the derivatives section of Borsa Italiana S.p.A. CDE is the platform where financial electricity derivatives contracts concluded on IDEX are executed. The contracts executed on CDE are those for which the Participant has requested to exercise the option of physical delivery of the underlying electricity in the Electricity Market (ME) all Participants of which are automatically admitted to the CDE. However, physical delivery in the ME is only requested by Participants holding an electricity account on the Electricity Account Registration Platform (PCE). Physical delivery takes place by registering an electricity purchase/sale transaction, of which GME becomes the counterparty. The transaction, having a sign corresponding to the delivered contracts, is registered on the electricity accounts that the Participant holds on the PCE.

5.3.3 The Forward Electricity Market

Forward electricity contracts with delivery and withdrawal obligation are traded in a venue called the Forward Electricity Market.

- All Electricity Market Participants are admitted automatically to the MTE.
- Trading in the MTE is on a continuous basis.
- In the MTE, the tradable contracts are Base-Load and Peak-Load, with monthly, quarterly and yearly delivery periods. (Technical Rule no. 01 rev4 MTE). Cascading mechanism is used to regulate the contracts with quarterly and yearly delivery periods.
- Market Participants register orders where they specify the type and period of delivery of the contracts, the number of contracts and the price at which they are willing to purchase/sell.
- After the trading period, the contracts with monyhly delivery are registered as corresponding transactions onto the PCE, after the adequacy verifications that are referred to in the PCE Rules.
- Also Over-the-counter (OTC) contracts may be registered in the MTE.
- GME acts as a central counterparty.

the sessions will be held from Monday to Friday, from 09:00 to 17:30, except on the next-to-the-last day of open market of each month, when the closing time is advanced at 14:00 for operational reasons.

5.4 Transmission Network

More than 90% of Italy's National Electricity Transmission is owned, developed and maintained by Terna, which was founded in 1999 as a separate company (100% owned by Enel S.p.A, Italy's incumbent). In the meantime, the grid management was consigned to a public operator named GRTN, which is controlled by the Ministry of Finance. Therefore, the organizational model of power transmission network in Italy was basically on Independent System Operator (ISO) model. In this model the ownership and the managing of the network were separated. However, Terna and GRTN were merged on 1st of November, 2005, i.e. the organizational model of Italy is now similar to the other European countries. This model is based on a Transmission System Operator (TSO) model, which owns and manages at the same time.

It's worth mentioning that, nowadays the major shareholder of Terna is Cassa Depositi e Prestiti, with 29.85% of shares. The remaining nearly 70% is divided between institutional and retail investors. Among the principal shareholders of the company: Romano Minozzi with 5.4%, and Assicurazioni Generali with 2.0%.

CHAPTER 6

Data and Assumptions

6.1 Introduction

The input data required are relevant to generating firms in the electricity market, power plant characteristics of each firm (costs and CO_2 emissions data), demand, transmission network data and investment costs. To reduce the size of the problem a number assumption has been made on firms and power plants' data; this allows the solver to conveniently handle the problem. The data and assumptions made are discussed in detail in the following sections.

6.2 Generating Firms' Data

In our study, the five largest generating firms namely Enel, E.on, Edison, A2A and Edipower are considered as strategic firms in the Italian electricity market; the other firms are aggregated to one single price taker firm. Also, for second and third model an another price taker firm is introduced which has the ability to invest in solar power plant.

6.3 Power Plants Data

Table 6.1 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.

Table 6.1: *Existing installed capacity of firms [MW]*

GenCo	Oil	CCGT	Coal	Import	Pump	GT	Bilateral	Hydro	Total
Firm1	3249	9249	4647	0	7073	3302	2395	6258	36173
Firm2	1373	4749	1209	320	0	0	922	834	9407
Firm3	362	4528	321	135	299	0	1888	377	7910
Firm4	109	1466	0	0	0	47	540	1868	4030
Firm5	1237	0	0	0	0	0	0	0	1237
Firm6	0	7384	0	6983	0	0	8776	502	23645

6.4 Data on Candidate Expansion Units

The data on expansion units considered are presented in table 6.2. 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 build new power plants based on technologies considered in table 6.2; moreover, the maximum new capacity per technology that firms are able to invest is assumed to be 4000 MW in each years in advance. plus, 2014 is the year that the firms could invest on new capacity according to table 6.2.

Table 6.2: *Data for candidate power plants*

Technology	Capacity cost [€/kW]	Variable cost [€/MWh]	CO_2 emission rate [tCO_2/MWh]
$CCGT$	600	53.79	0.36
$CCGT + CCS$	900	65	0.04
SCC	1250	17.75	0.90
$SCC + CCS$	1900	45	0.098

In addition, for the second and third model as described in sections 4.3 and 4.4, the firms are able also to invest on RES power plants. The data on RES expansion units that has been used in these models is depicted in 6.3. Also, it should be mentioned that in our assumption the firms are able to invest on RES power plants from 2011.

Moreover, as electricity production by wind plants depend to a large extent on wind conditions, choosing the right site is critical to achieve economic viability. Hence, due to mentioned issue, in our study firms are able to invest in offshore and onshore wind power plants only in zones 4, 5 and 6 which have a good wind conditions. On the other hand, in our study, there isn't such a limitation for solar investment .

Furthermore, maximum new capacity that the firms are able to invest on onshore wind power plant in each year in advance is assumed to be 500 MW except year 2011 which is 5850 MW. However, these values for offshore wind and solar are 100 MW and 500 MW respectively in each year in advance.

6.5 Demand Data

However, the load curve over each year consists of a number of blocks due to variations in electrical power demand, but in our study it has been considered as a single block. Since, our study considers 15 years planning period, hereupon, the equilibrium problem

Table 6.3: *Data for candidate RES power plants*

Technology	Incentive [€/MWh]	Capacity cost [€/kW]	Availability
Onshore wind	87.5	1200	15%
Offshore wind	122.6	1800	40%
Solar	100	3000	20%

is too large already. Hence, in order to reduce the size of the problem and consequently allows the solver to conveniently handle the problem the load of each year is represented by a single block.

Moreover, a common demand elasticity ϵ=0.2 €$/MW^2h$ 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, which has been updated taking into account an inflation rate (3%) and an yearly increase factor respectively.

6.6 Data on Transmission Network

Geographically, the Italian electricity market is scattered into several areas. Each area identifies a delimited grid area in which congestions are less frequent that is connected through a critical section with other neighboring areas. The TSO defines these areas and makes frequent modifications to the geographical boundaries of a zone either by unification two zones or splitting an existing zones depending on the observed congestion.

Figure 6.1 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 (see figure 6.2).

The data for inter-zonal transmission limits were obtained from Terna [2]. The market is modeled by a linearized DC network using Kirchhoff's laws and Power Transfer Distribution Factors (PTDFs). In our model, Sardinia has been chosen as a hub node since the linear property of DC models makes the choice of hub node arbitrary. Also, network expansion has been considered negligible during the 15 years planning period.

6.7 Data on CO_2 Emissions Allowance Price

As described in the section 4.2.4, CO_2 price is given exogenously to the model. Six different CO_2 prices are considered in this study, namely 10, 20, 30, 40, 50 and 60 €/tCO_2 and compared with the base case characterized by a zero CO_2 price. It should be noted that, the actual CO_2 price during 2010 was approximately 16 €/tCO_2.

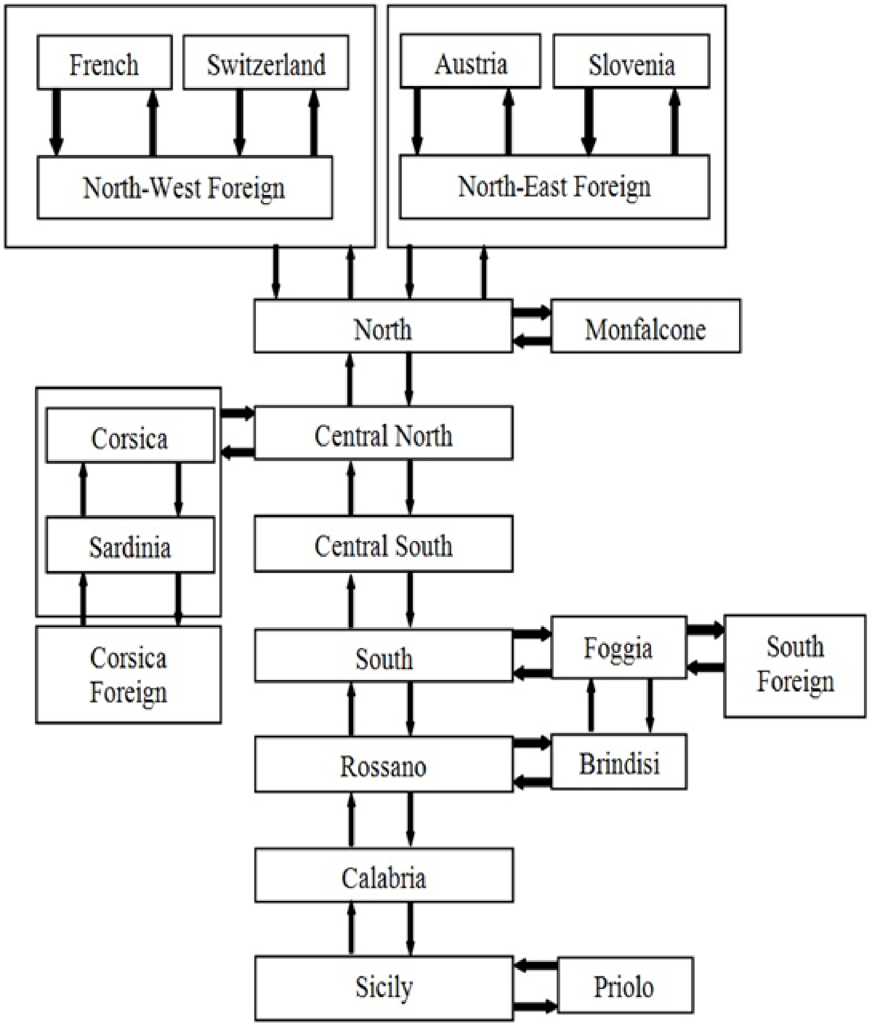

Figure 6.1: *Italian zonal market structure*

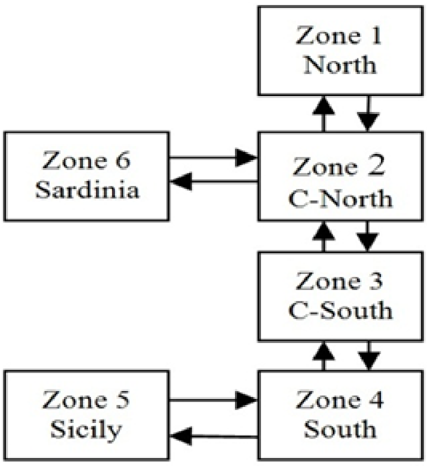

Figure 6.2: *Zonal structure implemented in the model*

CHAPTER 7

Results and Discussion

7.1 Effect of CO_2 Emission and Transmission Constraints

7.1.1 Introduction

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, namely 10, 20, 30, 40, 50 and 60 [€/tCO_2] and compared with the base case characterized by a zero CO_2 price.

7.1.2 Electricity prices

The introduction of a CO_2 price changes the short-run marginal cost of power plants and hence the electricity prices. Figure 7.1 shows the average electricity prices during the planning period in each zone as Pc increases. Due to the Italian system structure adopted in the simulation, the average prices of the zones 2, 3 and 4 are the same, because no congestions are present. Figure 7.1 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 Pc=0 [€/tCO_2] and for Pc=10 [€/tCO_2] are shown in figure 7.2 and 7.3 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 7.4, it is clear that, in 2014, generation companies are in the conditions to invest in new generation.

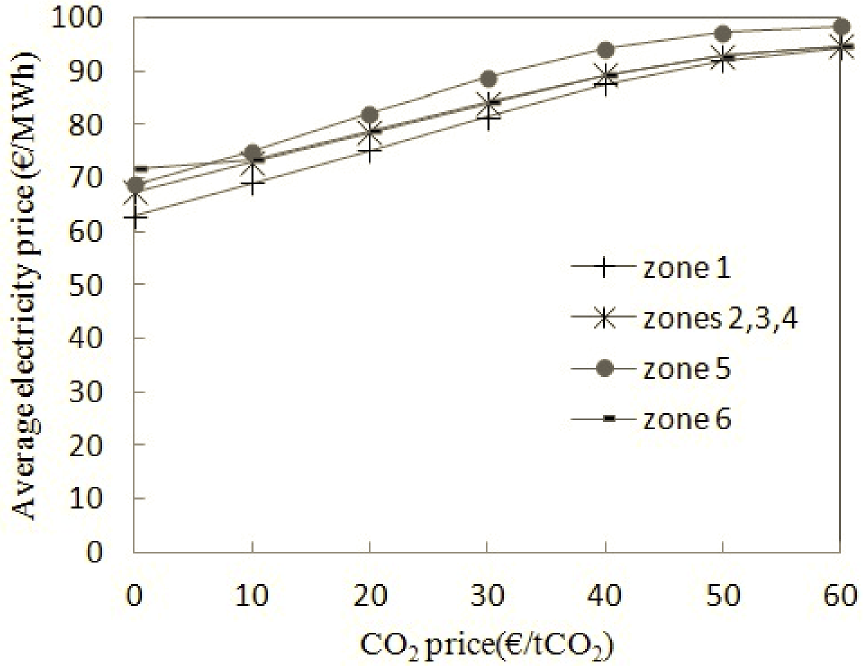

Figure 7.1: . *Average electricity price during 2010-2024 at selected Pc in all zones.*

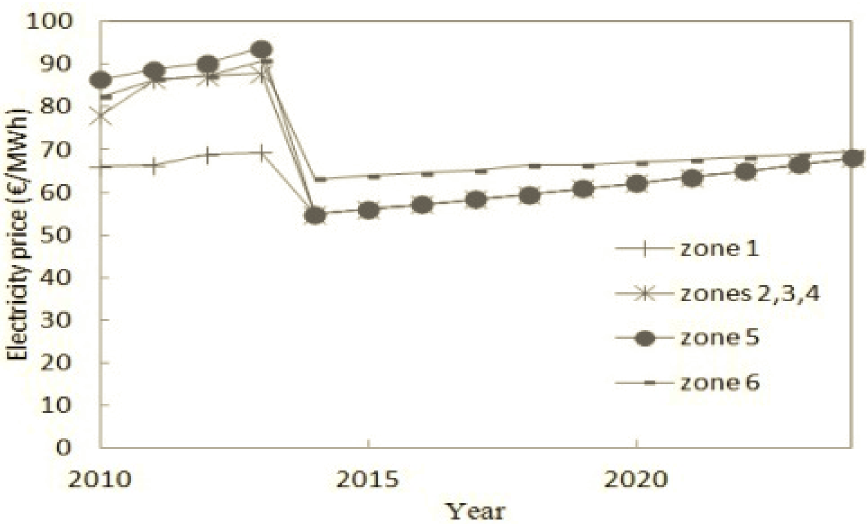

Figure 7.2: *Electricity price during 2010-2024 at Pc=0 [€/tCO_2] in all zones.*

7.1.3 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 7.5 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 7.5 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

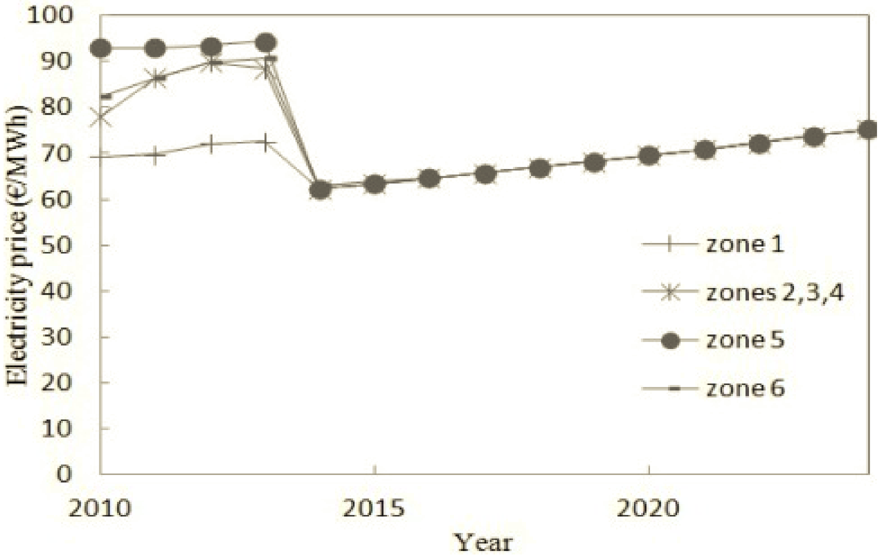

Figure 7.3: *Electricity price during 2010-2024 at Pc=10[€/tCO_2] in all zones.*

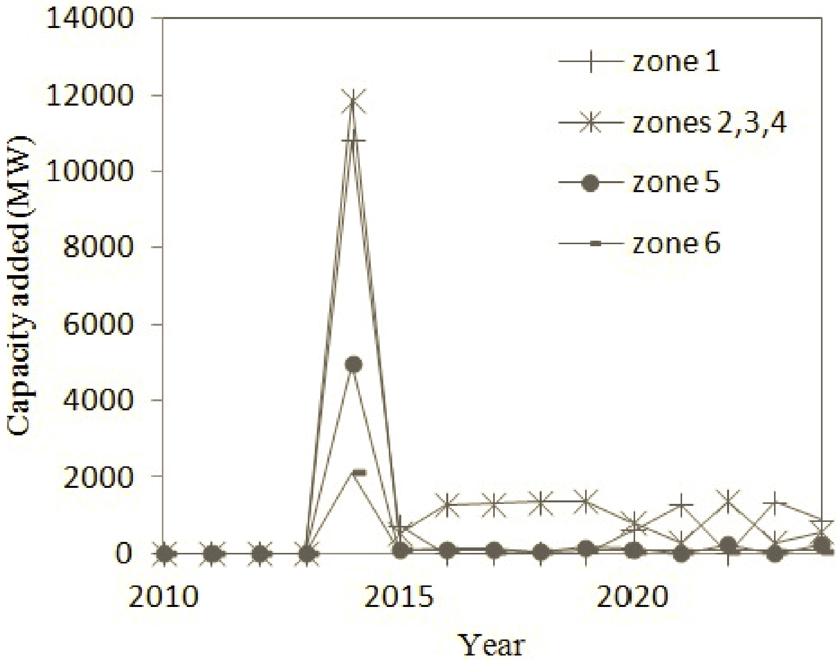

Figure 7.4: *Capacity added during 2010-2024 by zone.*

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 Figure 7.6 depicts.

In order to better understand which zone has more potential for investments in future years, figure 7.6 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

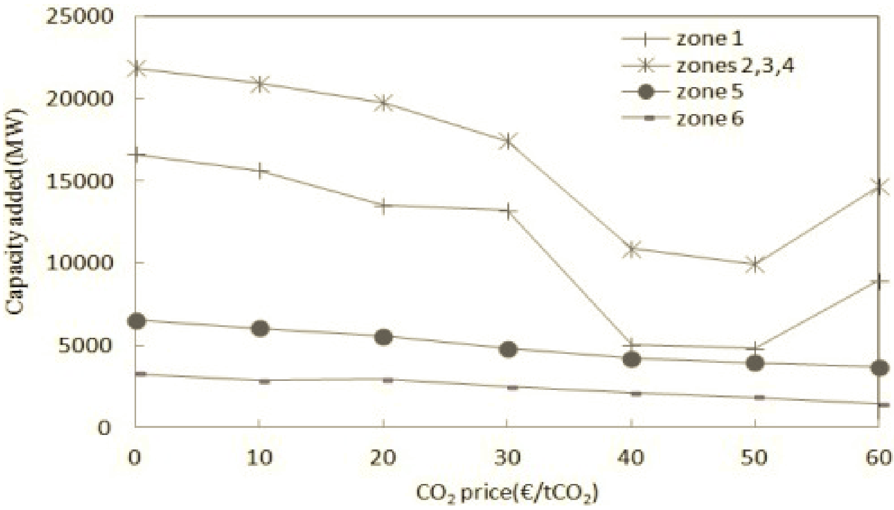

Figure 7.5: *Capacity additions during 2010-2024 (MW).*

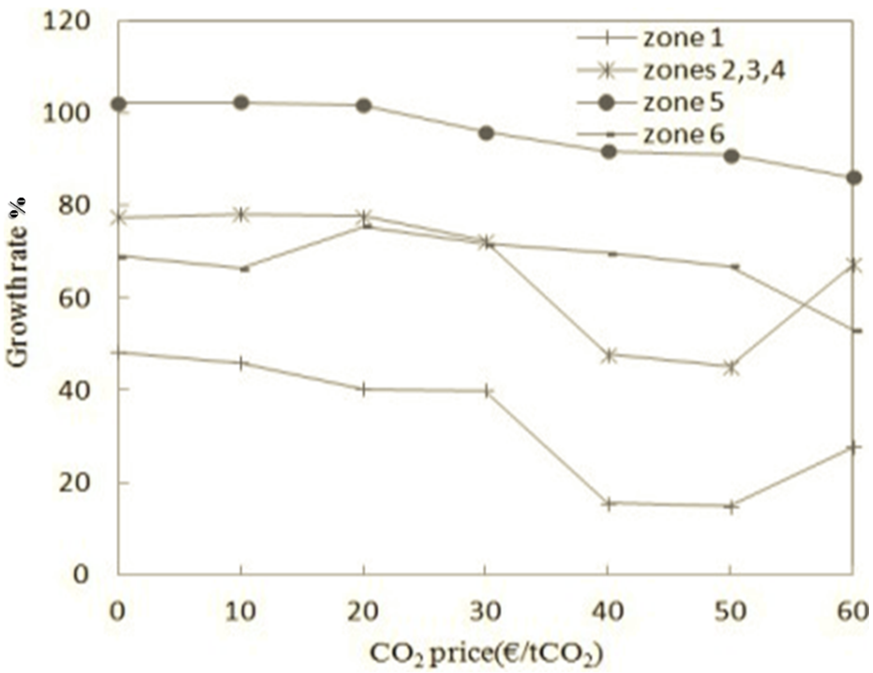

Figure 7.6: *Percent growth rate of capacity expansion*

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 Figure 7.6. 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 consid-

ered years, but it is offset by the high demand in 2024.

7.1.4 Power Plant Technology

Table 7.1 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 7.1: *Capacity additions by technology during 2010-2024 (MW)*

zone	Technology \ CO_2 Price €/tCO_2	0	10	20	30	40	50	60
1	SCC	16639	15637	13504	13209	5044	0	0
1	$SCC + CCS$	0	0	0	0	0	4814	8958
2	SCC	9224	4960	9296	8398	1225	0	0
2	$SCC + CCS$	0	0	0	0	0	1435	3915
3	SCC	5299	8632	3570	2564	4260	0	0
3	$SCC + CCS$	0	0	0	0	0	3512	4369
4	SCC	7369	7369	6934	6503	5423	0	0
4	$SCC + CCS$	0	0	0	0	0	4997	6409
5	SCC	6544	6061	5571	4826	4216	0	0
5	$SCC + CCS$	0	0	0	0	0	3938	3677
6	SCC	3265	2879	2942	2477	2104	0	0
6	$SCC + CCS$	0	0	0	0	0	1840	1427

Table 7.1 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 $SCC+CCS$.

7.1.5 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 7.2 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].

Table 7.2: *Generation mix (%) during 2010-2024 at selected CO_2 prices*

Technology \ CO_2 Price €/tCO_2	0	10	20	30	40	50	60
$CCGT$	4.13	4.1	4.24	4.95	22.04	23.17	8.29
OIL	15.19	15.74	16.40	16.83	16.56	14.63	2.91
$COAL$	0.55	0.46	0.26	0.06	0	0	0
$HYDRO$	14.1	14.57	15.2	15.85	16.55	17.03	17.29
$PUMPING\ STORAGE$	0	0	0	0.03	0.74	0.76	10.38
$BILATERAL$	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	47.8	45.84	43.44	24.44	0	0
$SCC + CCS$	0	0	0	0	0	24.34	41.06
$total(TWh)$	7817.1	7543	7236.1	6935.6	6644.4	6458.5	6357.7

7.1.6 Profits of Firms

Table 7.3 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].

Table 7.3: *Profit of firms during 2010-2024 at different Pc [10^{10}€]*

Pc [€/tCO_2]	Firm1	Firm2	Firm3	Firm4	Firm5	Firm6
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

7.1.7 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 7.7 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 $SCC+CCS$.

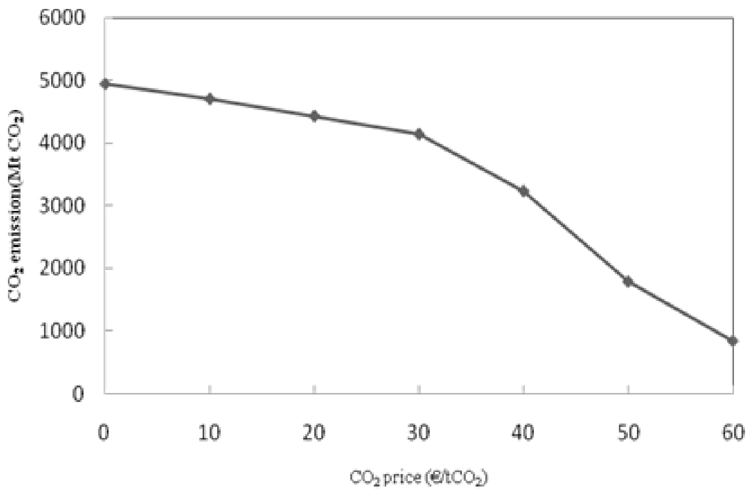

Figure 7.7: *Total cumulative CO_2 emission during 2010-2024 at selected CO_2 prices.*

7.2 Effect of Different Incentive Plans

7.2.1 Introduction

The second GEP model is applied to the Italian electricity market to investigate the impacts of different incentive plans on the Italian electricity sector in terms of changes in electricity prices, investment decisions, profits of different companies, and CO_2 emissions. It should be mentioned here that, firstly the real incentive value of Italy according to the table 6.3 is applied and then some assumption is organized to observe the possible changes in RES expansion.

Seven different CO_2 prices of 0, 10, 20, 30, 40, 50, and 60 €/tCO_2 are considered in this study. Unlike previous test, the electricity sales through bilateral contracts and imports by each firm are not considered here in order to reduce the size of the problem.

7.2.2 Electricity Prices

Obviously as the price of CO_2 emission, which has been considered exogenous in our model, rises, it leads to increment of marginal cost in each firm and consequently will give rise to market price at each node. Our evaluated results coincide with the same fact. On the figure 7.8 the average electricity prices during the planning period are depicted at each node.

Moreover, the yearly prices for different Pc demonstrate this fact that in 2014 an important change happens, related to the change of the marginal technology (since, in 2014, sterategic firms are in the conditions to invest in new generation on SCC or SCC+CCS depending on the different assumed CO_2 prices) that results in reduced prices after 2014. Just a sample, figure 7.9 depicts the yearly prices for Pc=10 €/tCO_2.

7.2.3 Power Plant Technology

Figure 7.10 presents capacity additions (SCC&SCC+CCS) during 2010-2024 at selected CO_2 prices in all nodes. It is also worth mentioning that the CCGT and CCGT

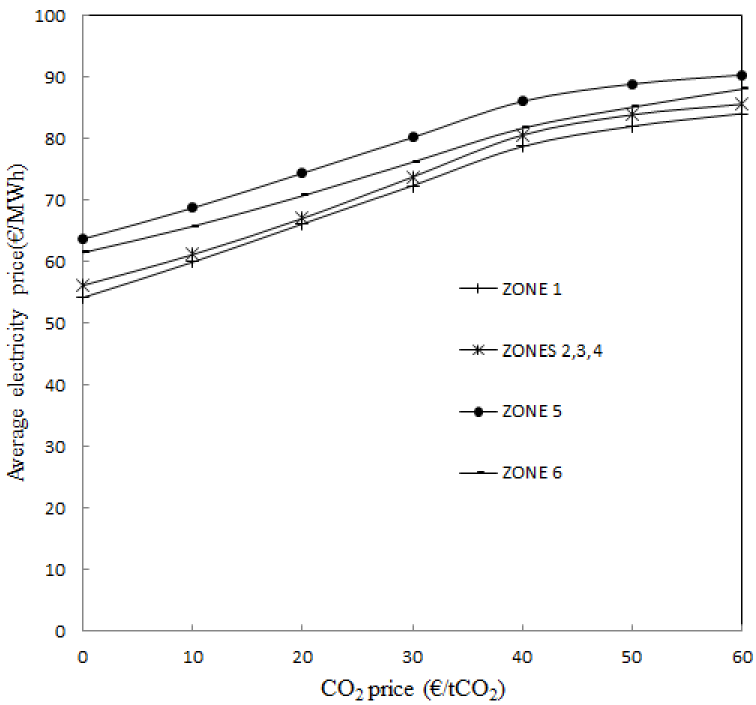

Figure 7.8: *Average electricity price during 2010-2024 at selected Pc in all zones*

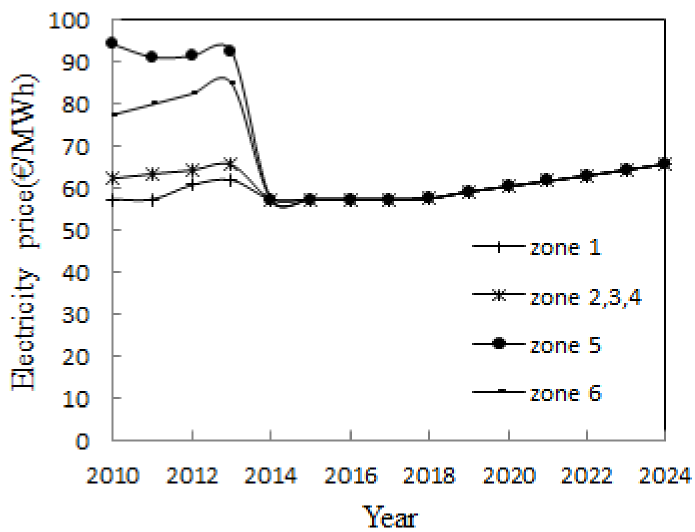

Figure 7.9: *Electricity price during 2010-2024 at Pc=10 €/tCO_2 in all zones*

with CCS power plants are never selected by the model during planning period, due to the lower variable cost of the SCC or SCC+CCS technologies. As it can be observed on the figure, as long as carbon price stays below 40 €/tCO_2, firms tend to use super critical coal power plants due to their low marginal and capacity costs. However, as soon as the price of the carbon reaches to 50 €/tCO_2 firms incline toward switching from super critical coal to super critical coal with paired CCS power plants. In such cases, emission factor overweighs the low marginal and capacity costs of the former power plant. Since, super critical coal power plants with paired CCS have much less emission factor in comparison with super critical coal type.

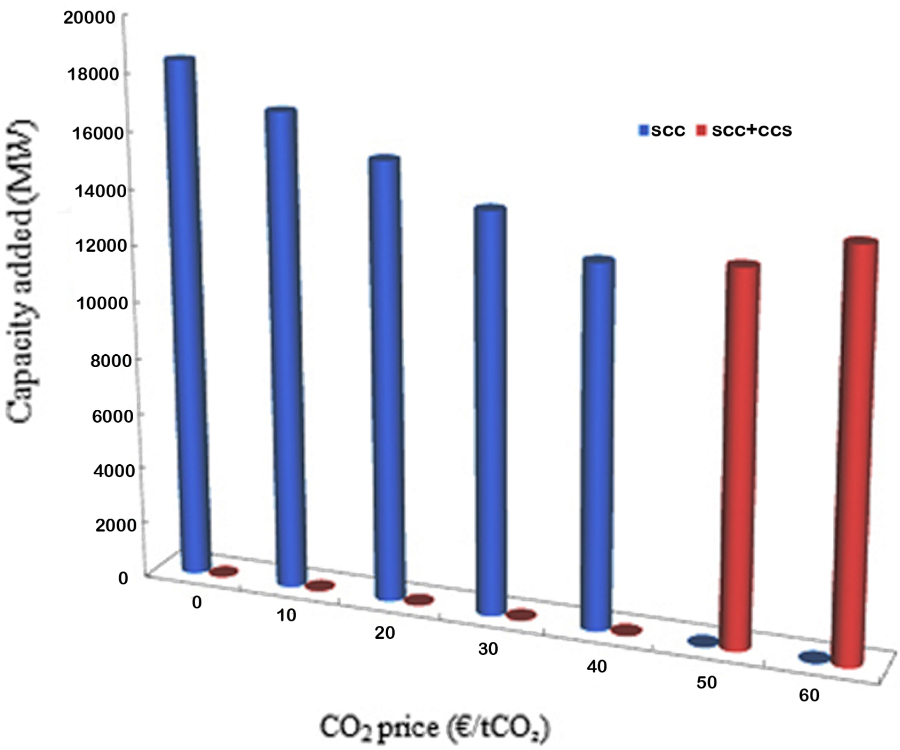

Figure 7.10: *Capacity additions (SCC&SCC+CCS) during 2010-2024 (MW) at selected Pc in all zones*

Also, figure 7.11 shows capacity additions (onshore and offshore wind power plant) during 2010-2024 at selected CO_2 prices in each node. Since, zone 5 has the highest electricity prices during 2011-2013; it is more profitable for firms to invest in zone 5 in the mentioned years rather than other zones. As soon as the firms could invest on the clean coal technologies (which it happens in 2014), the price signals are getting unique and sufficient enough to drive the producers in building capacity where necessary.

Figure 7.12 demonstrates capacity additions (solar) during 2010-2024 at selected CO_2 prices in all nodes. As it can be seen in the figure, the capacity addition for this kind of power plant reaches its maximum assumed value which is 500 MW in each year in advance in all CO_2 prices except for the base case. It is worth noting that, for the base case scenario, only in years 2023 and 2024 there were no solar capacity addition. For the reason that, the investment cost of solar in these mentioned years can not be recouped due to its availability factor, incentive value and also the low value of market price.

7.2.4 Generation Mix

Introducing CO_2 price, the production cost of firms will change. Consequently generation mix will be affected due to the tendency of firms to utilize technologies which have less carbon emission. Figure 7.13 demonstrates the generation mix by fuel type at

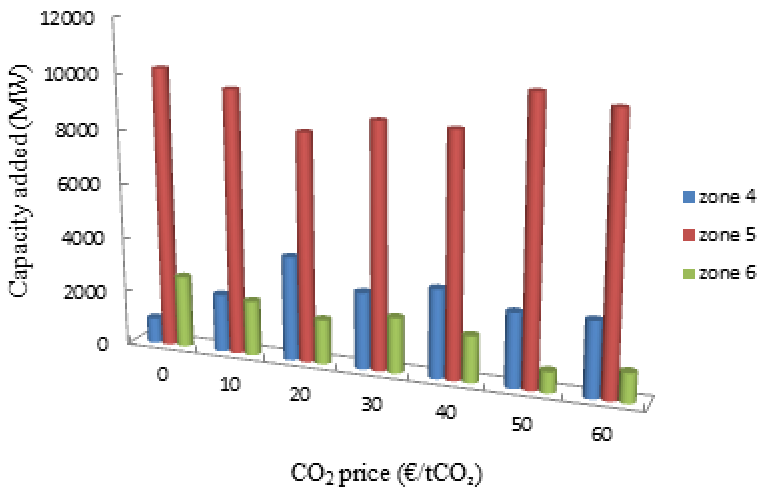

Figure 7.11: *Capacity additions (onshore and offshore wind power plant) during 2010-2024 (MW) at selected Pc in different zones*

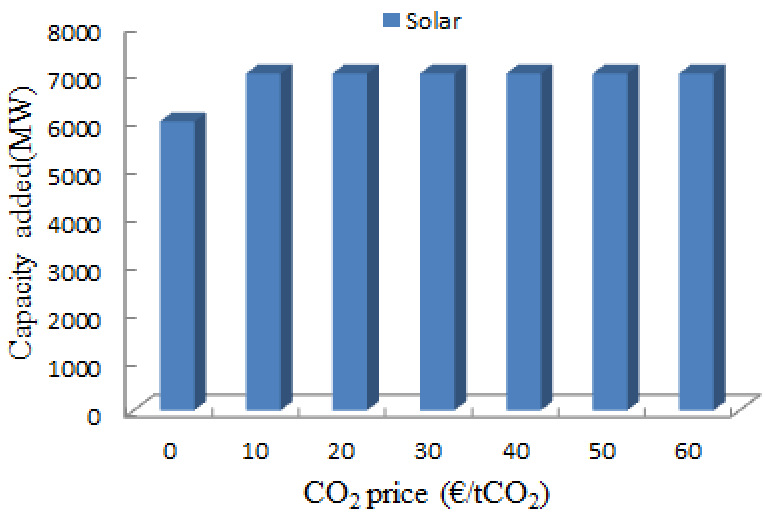

Figure 7.12: *Capacity additions (solar) during 2010-2024 (MW) at selected Pc in all zones*

selected Pc (0, 20, 40 and 60 €/tCO_2) in the considered time horizon. At low levels of carbon price (up to 10 €/tCO_2) there is no drastic change in generation mix. However, as soon as the price reaches 20 €/tCO_2 the role of CCGT power plant becomes more significant. At price 50 €/tCO_2, CCGT remains almost the same however the use of SCC with paired CCS power plants start emerging. As the price continues rising, taking advantage of SCC with CCS power plants becomes dominant.

7.2.5 Profits of Firms

Figures 7.14 and 7.15 demonstrate the effect of carbon emission price on the total profit gain for different firms (strategic and price taking) over the years 2010-2024. It should be noticed here that all the price taking firms in Italy are accumulated under the name PT firm 1. Hence in our model no ability of capacity addition is considered for this

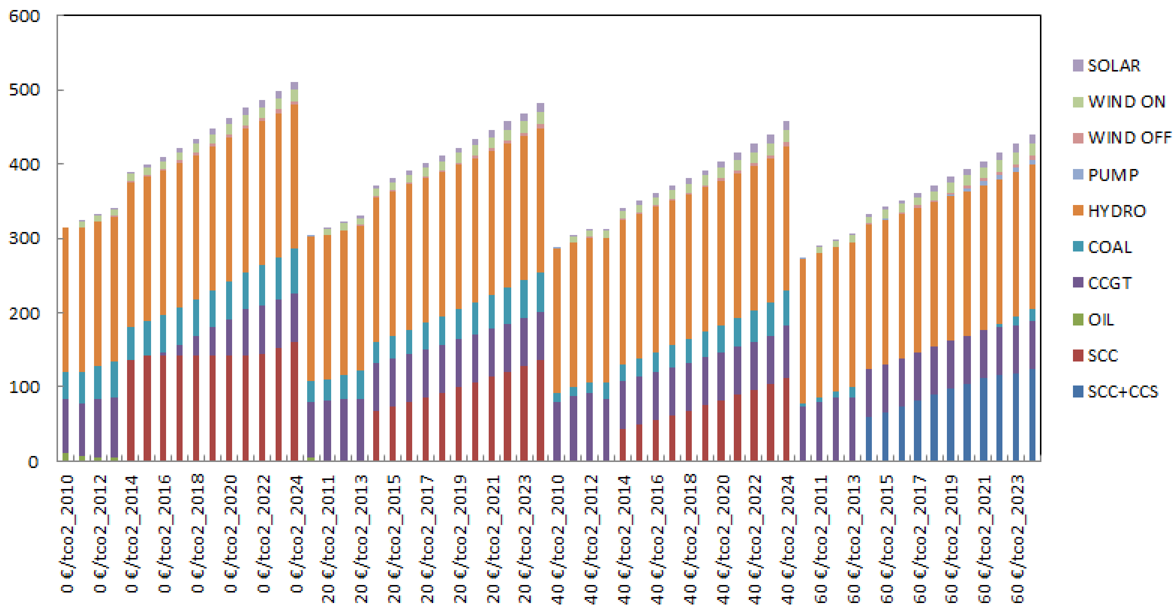

Figure 7.13: *Generation mix by fuel type at selected carbon prices (TWh)*

firm. On the contrary, PT firm 2 is considered as an another price taking firm which is able to install new capacity on solar.
Firm 1 which due to its resistivity to capacity addition it's profit keep almost constant until the price reaches to 40 €/tCO_2 and then decreases. However, firm 2, 3, 4 and 5 show different behavior due to their investment in new generation capacity. The profit of PT firm 1 continues growing until the price reaches to 40 €/tCO_2. Because increasing the price of market benefits this firm more than the amount which marginal and emission factor cost. However, its profit tends to decrease at 50 €/tCO_2 and above as strategic firms switch their capacity additions from SCC to SCC+CCS.

Also, as it is evident from 7.15, while the price of CO_2 emission rises, it leads to rise in market price and consequently will give rise the profit for PT firm 2.

7.2.6 CO_2 Emissions

By introducing CO_2 emission price in our model, firms show a tendency to decrease the CO_2 emission in order to gain more profit. Hence, the study of this behavior in the years ahead seems to be interesting. As it is shown in figure 7.16, while price of the CO_2 emission equals 40 €/tCO_2, there is a 24.5% mitigation in CO_2 emission with respect to reference price (Pc=0). This reduction becomes more noticeable as the CO_2 emission price grows. Namely, increasing the CO_2 emission price from 50 to 60 €/tCO_2 lowers emission from 54.2% to 68.7%.

7.2.7 Effects of Incentives on Investment Decision of RES

Few tests have been organized in order to analyze the impact of different incentive plans on renewables expansion. Accordingly, for the base case scenario, the value of incentives for all RES have been decreased 15%, 25% and 50% with respect to the real incentives.

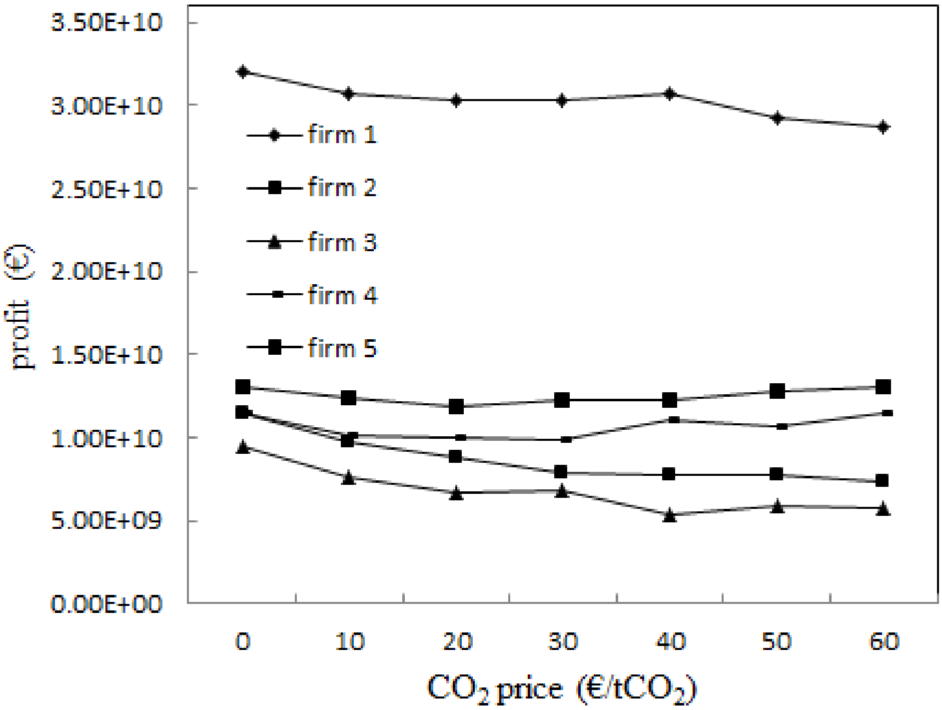

Figure 7.14: *profit of strategic firms during 2010-2024 at different Pc*

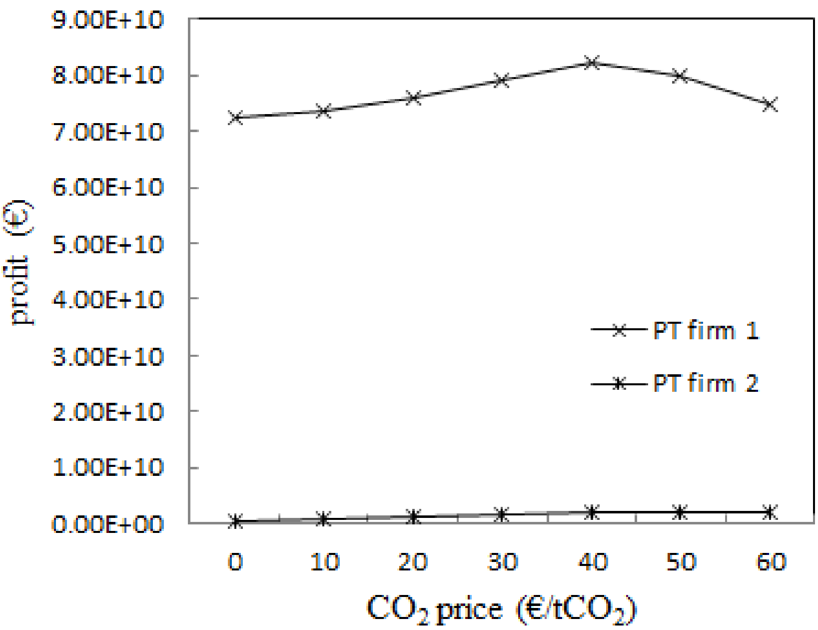

Figure 7.15: *profit of price taking firms during 2010-2024 at different Pc*

Figure 7.17 shows the capacity added for solar at Pc=0 for different incentives scenario. It is showing that the capacity added by solar decreased drastically, whereas incentives of the RES decreased up to 15%.

It is interesting to survey some features of solar capacity addition that are not evident

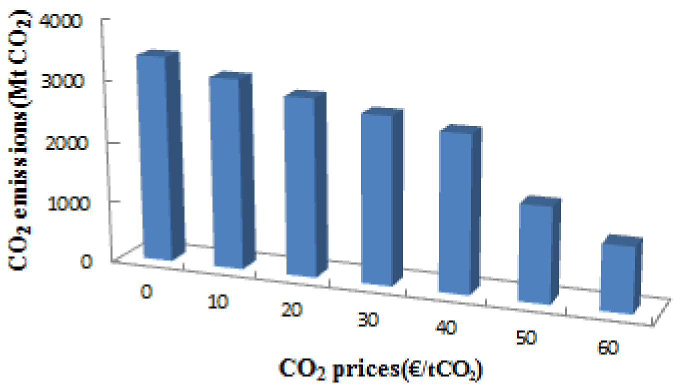

Figure 7.16: *Total cumulative CO_2 emission during 2010-2024 at selected CO_2 prices*

from figure 7.17. In case of 15% decrement in incentives, the capacity addition of solar happened only in 2011 and 2012 and afterwards it was not profitable for price taker firm to invest on solar. This is because of its high investment cost and low value of availability factor. It should be mentioned here that the solar power plant never selected by the model when the value of incentive decreases up to 25%.

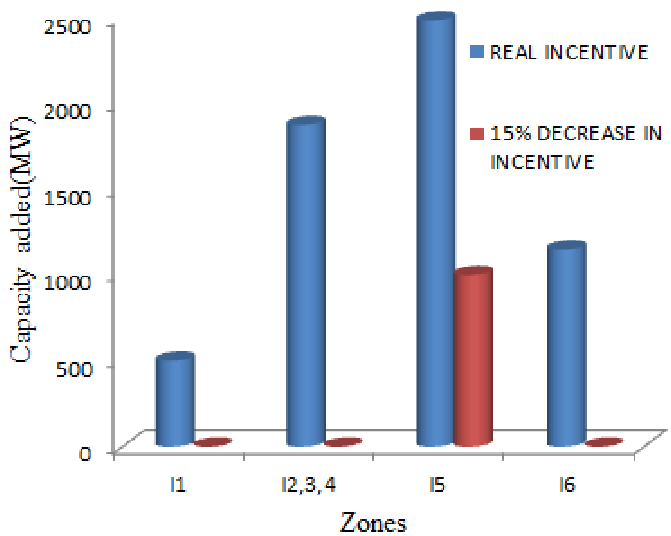

Figure 7.17: *Capacity added for solar(Pc=0)*

On the figure 7.18 the capacity added for onshore wind at Pc=0 for different incentives scenario is presented. It should be noticed here that, while there is 25% decrement in incentives, the capacity added by this kind of power plant is remained the same in comparison with the real incentives scenario. Although, as far as the decrement reaches to 50%, capacity addition by onshore wind power plant happened only during 2011-2013 and after that it is more profitable for firms to invest in clean coal technology rather than onshore power plant.

As it is shown in the figure 7.19, by decreasing the value of incentives up to 50%, wind offshore power plant is still more favorable to invest in comparison with onshore

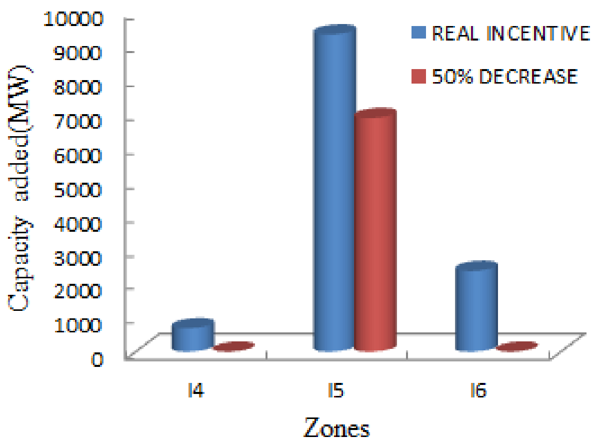

Figure 7.18: *Capacity added for onshore wind(Pc=0)*

wind. Because despite the fact that the capital cost of the wind offshore power plant is higher than the onshore power plant, however the incentive and availability factor of offshore makes it more profitable to invest rather than onshore power plant. It should be paid attention that the capacity additions are highly dependent to the market price which is set by the GEP model.

It is worth considering that, as the value of incentives decreased up to 50%, the solar power plant never selected by the model and also the installed capacity for onshore power plant drastically decreased, hence producers install offshore wind power plants where required.

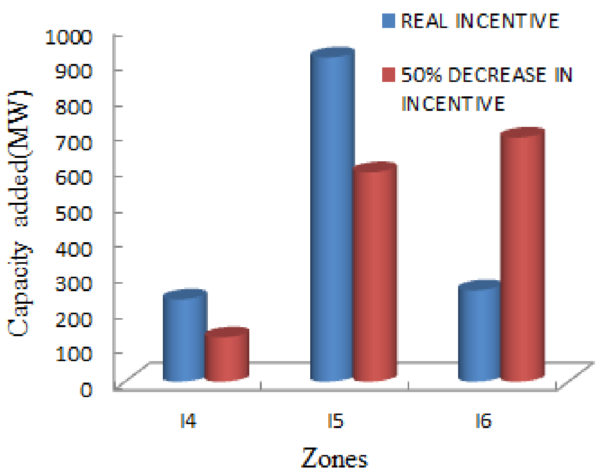

Figure 7.19: *Capacity added for offshore wind(Pc=0)*

7.3 Effect of already Installed CCGT on Generation Mix

7.3.1 Introduction

There are power plants in the electricity market that have been installed many years ago but their investment costs have not been recouped yet. In this context, recovering the investment cost of these power plants in the long run could change the generation mix and also the future investment decisions.

In this test, a base case scenario is assumed. Because, at Pc=0, existing CCGTs are producing less electricity in 2014 to 2024 when the firms have the ability to invest a new capacity according to the table 6.2. Consequently, in order to observe the effects of already installed CCGT power plants on the generation mix & future investment decisions, it would be easier to compare this model with the previous one for the base case scenario. It should be mentioned that in this test, the already installed CCGT power plants have to recoup 10% of their investment cost during the planning period.

7.3.2 Comparison

Figure 7.20 depicts the average electricity prices during the planning period at Pc=0 for models 2 and 3 at each node. Take a look at the figure reveals that the average prices of this model are higher than the previous one on account of the constraint 4.65 must be fulfill for already installed CCGT power plants.

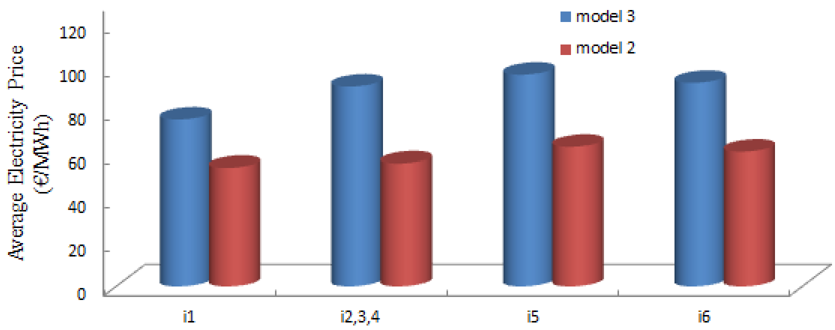

Figure 7.20: *Average electricity price for model 2 and 3 during 2010-2024 at Pc=0*

Also, figures 7.21 and 7.22 show the changes in generation mix over the planning period at Pc=0 for models 3, 2 respectively. As it is recognizable in the figure 7.21, unlike the generation mix shown in figure 7.22, the CCGT power plants (in our study they are already installed power plants that should recoup 10% of their investment cost during planning period) came to the service to recoup their investment cost even after year 2014 while strategic firms are able to invest on clean coal technology. Accordingly, the capacity added by SCC power plants are decreased.

On the figure 7.23 the cumulative CO_2 emissions during the planning period at Pc=0 for both models is depicted. As it can be seen from the figure, while price of the CO_2 emission equals 0 €/tCO_2, the total cumulative CO_2 emission in model 3 is less than the model 2. Since, the model force CCGT power plants to come to the service which has the lower emission rate in comparison with SCC power plants, consequently total cumulative CO_2 emission has been decreased.

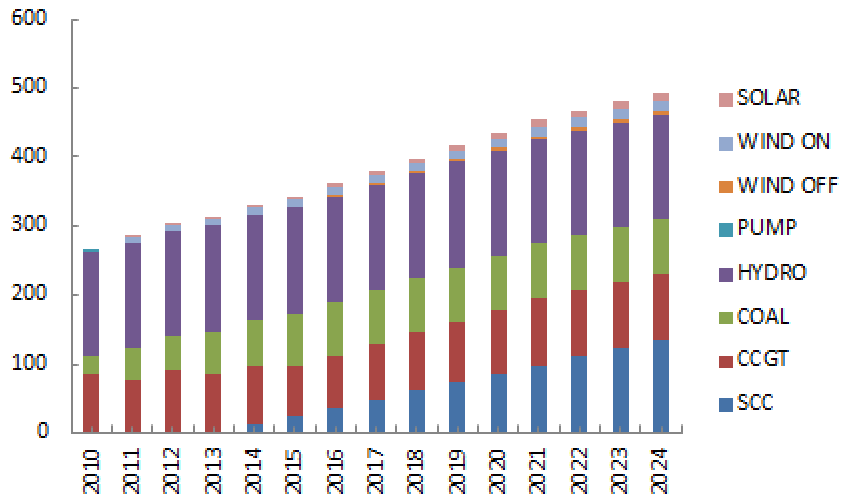

Figure 7.21: *Generation mix by fuel type for model 3 at Pc=0 (TWh)*

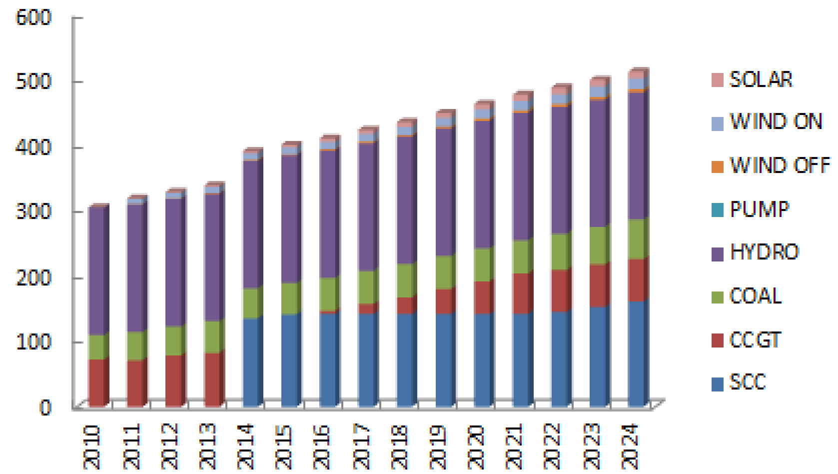

Figure 7.22: *Generation mix by fuel type for model 2 at Pc=0 (TWh)*

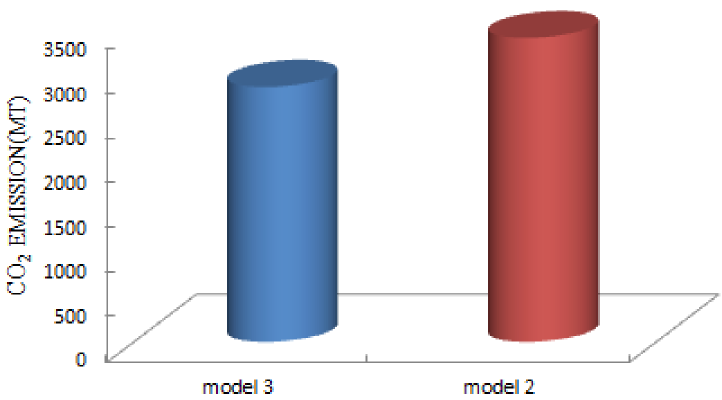

Figure 7.23: *Total cumulative CO_2 emission (Mt) for model 2 and 3 during 2010-2024 at Pc=0*

CHAPTER 8

Conclusions and Future Works

8.1 Conclusions

This study presents an oligopolistic GEP model in the presence of transmission constraints for analyzing generating firms' investment decisions under different CO_2 reduction targets. In addition, a model that allows the assessment of the impacts of the different incentive plans on RES expansions is also presented. Finally, a model which able to consider the already installed power plants that have been installed several years ago but their investment costs still not recouped is given.

Although many models exist that look into GEP in oligopolistic markets, there are only few GEP models that take into account environmental considerations. Moreover, there are no detailed models that take into account consideration both transmission constraints and emission constraints. Due to the fact that the generation capacity expansion may lead to add or relieve congestions in transmission, it is very important to include the transmission network representation in the GEP models.

In this study, a rigorous GEP model has been developed that can analyze impacts of different GHG mitigation polices such as emission reduction targets & emission trading and different incentive plans on the investment decisions in transmission constrained oligopolistic markets. Moreover, the model is able to consider the effects of already installed power plants-by considering their investment cost-on the generation mix.

The ability of the proposed models are demonstrated with reference to the transmission constrained Italian electricity market and to the European emission trading system, showing the possibility to model real markets and systems.

8.2 Future Works

Future research may focus on following two areas:

- Future research may carry out to integrate the existing uncertainties over the load and commodity prices via implementing stochastic model.
- Future research may include improvement of mathematical models in order to give algorithm the capability to converge using less computational burden.

CHAPTER 9

Islanding in Sub-transmission grids

9.1 Introduction

The main idea of the research project is to define the possibility, for the subtransmission network or a part of it, to survive to a disconnection from the bulk power system. It means that the behavior of the frequency in transient from normal operation to islanding should be under tolerance of the protection settings of the subtransmission system. By defining the control variables in mathematical model and evaluate them by simulation the behavior of the frequency can be controlled.

In general, disconection of subtransmission system from the bulk power system can be due to:

Intentional actions This is the case of local systems that are designed for islanded operations. A couple of examples can be provided:

- Industrial areas where local generation is in operation, that can separate from the remaining part of the transmission system in case of perturbations in the bulk power system (e.g., in case of risk of blackout). Typically, the interconnection is made by means of a single breaker that, in case problems of frequency or voltage are detected, automatically opens and trigger a procedure to balance the industrial load, for example by shedding not essential loads. As the local system is designed for that kind of operation, the most frequent operating conditions are known, the technical features of the generators and the turbines are known and the procedure is likely to be successful.
- Transmission system areas that can trigger islanded conditions in case of large frequency perturbations in the transmission system, according to well defined System Protection Schemes and contingency plans. This possibility is not

considered in the current Italian contingency plan, where all generators at all voltage levels are expected to contribute to the balance of the system during the perturbation (although in different ways based on the frequency relays settings); in some Countries, however, islanding is considered a countermeasure to "save" a part of the load in some specific balanced areas, that can be detected on line by means of adaptive schemes. In this case, the contingency plan and the set of devices able to start islanding procedures must be carefully designed, as the operating conditions of the bulk power system at the moment of the event is not known *a priori* and can be very different from time to time. Moreover, at the transmission level, the intentional islanding procedure must be activated by the opening of many breakers, not by a single breaker operation. This makes it necessary to include in the analysis complex time-domain simulations to check the feasibility of the islanded operation.

- A third possibility is the intentional islanded operation of a part of a system due to reconfiguration of the system in the absence of any particular critical condition. In this case, all the control actions are taken according to specific, detailed and tested procedures aimed at avoiding technical problems and imbalances.

Unintentional operation A different situation can occur if the islanding is started by the operation of a breaker due to the triggering of the protections system. For example, this is the case in radial distribution systems where, due to a fault and the consequent operation of a breaker, the terminal part of a feeder becomes islanded and, if generation is available, can continue the operation in case the generation is able to balance the load.

In more complex topological schemes, e.g., in case of subtransmission or even transmission meshed systems, this type of unwanted islanded operation becomes more and more unlikely to occur due to the fact that the simultaneous operation of two or more (depending on the meshing of the grid) breakers should start the islanding; this could occur in case of simultaneous multiple faults, which is clearly more and more unlikely. Moreover, in this case, it is also difficult to design the islanding system, because not only the operating conditions - after the islanding - can be very variable in time and therefore difficult to predict, but also the faults that cause the opening of breakers influence the overall dynamic of the system, thus making very difficult to design an automatic system able to guarantee the success of the islanding procedure for all the starting events.

The present research deals with the possibility to operate a part of the subtransmission 132/150 kV system that, following the operation of the breakers, results in islanded conditions. In particular, the generation from RES is to be exploited to check the ability of the currently available technologies in providing the necessary regulating capability. In other words, in the present study, the dynamic behaviour of the system that resulted in the islanded conditions is neglected.

9.2 Islanding in subtransmission systems

In order to exploit islanding in the subtransmission systems, it is necessary to investigate on the topology of that systems and on its regulating resources. Currently, subtransmission feeders are connected to the higher voltage levels (transmission system) through some connection points at the substations. The connection points can be two or more, depending on the structure of the system. For example, in the test system A, reported in figure 9.1, two connection points are present: therefore, it is necessary that two breakers operate, in order to give the conditions for an islanded situation.

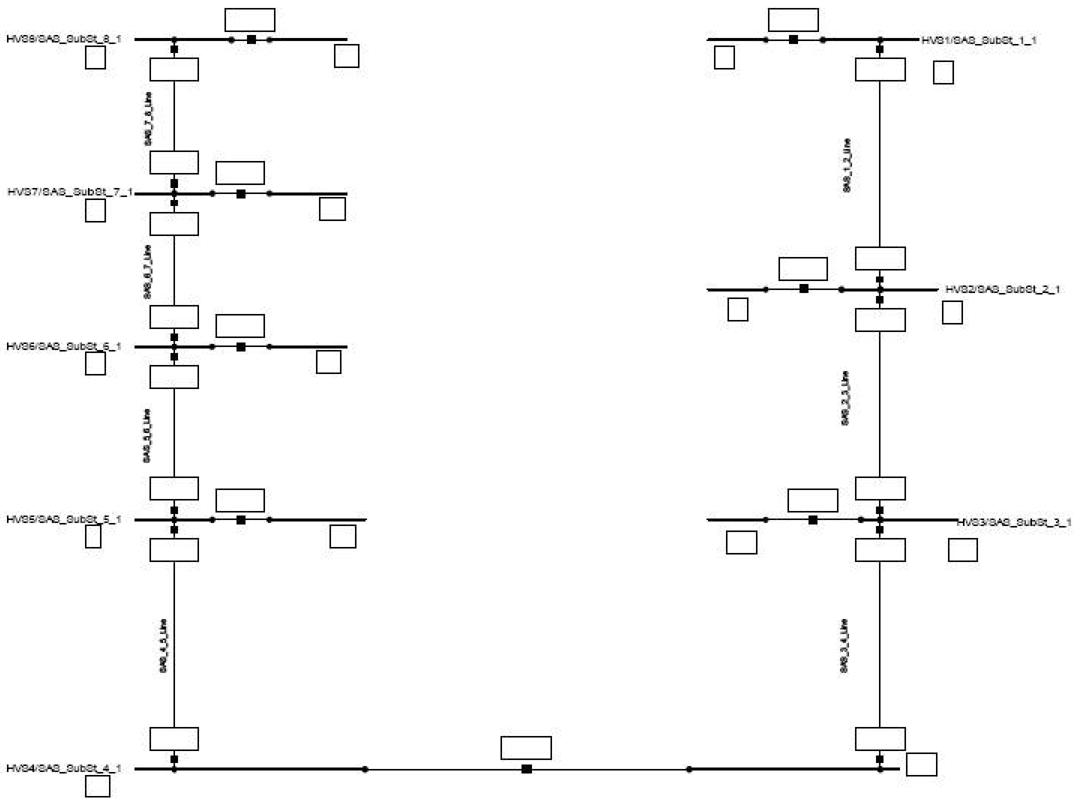

Figure 9.1: *Test System A*

Regardless the reasons that resulted in an islanding (more or less extend in the space), in the "old" approach, once a part of the subtransmission system experiences the islanding, the probability that it survives depends on the ability to balance the load and generation as well as on the voltage control features, without resulting in further operation of the protection system that could further jeopardize the islanded system.

All the above mentioned parameters in today subtransmission systems are not typically controlled or designed for such events, and therefore, the probability of successful operation of the islanded system following the initial events is in any case very low, in some way random, due to the uncertainties on loads, generation and so on.

In the following sections, an innovative function of the proposed Substation Automation System (SAS) is presented, to increase the probability of successful islanding by means of possible control actions available on both the generation and the load side.

The described procedure is carried out every 5 to 15 minutes to generate a table where, for each set of N breakers opening, that could result in an islanded operation, the set of control actions to be carried out is defined. In case of any islanded operation, therefore, each SAS must actuate them, thus maximizing the probability of successful islanded operation.

9.3 Finding the feasibility for islanded operation

The SAS island feasibility function is an innovative concept in the Smart Grids framework. It was studied to give the possibility to supply load by means of any regulating resource, in particular renewable generation, even in case the subtransmission grid is (partially) disconnected from the transmission network. The goal of this function is to determine, for a given operating condition and a set of triggering events, the possibility for islanded operation of the 132/150 kV subtransmission system. Also, in case of feasibility, the procedure determines the control actions to be put in place.

The island feasibility function has a preventive character and it requires the definition of:

- a monitored area;
- a master SAS in that area to run the procedure every 10-15 minutes.

In this regard, the master SAS will:

- receive information from the other SASs of the monitored area; in particular
  - the generation and load profile;
  - the continuously up and down controllable resources;
  - the discrete up and down controllable resources, according to different step sizes (load shedding, generation shedding);
- elaborate information and determine, for each set of possible triggering events, if islanding is feasible from a steady-state perspective; in case of positive answer, the SAS will also have to determine the set of control actions to be taken if the events will occur;
- communicate to the other area SASs the complete matrix reporting the results (what-to-do-if);
- in case the area becomes islanded, the master SAS will communicate the borders of the area that became islanded and each SASs will act according to the matrix above defined.

9.4 Mathematical Model

The procedure can be mathematically expressed as a constrained integer programming problem that, in a basic approach, maximizes the load to be supplied after islanding:

$$\max Load = \max \Big[\sum_{i=1}^{N_{SAS}} \sum_{j=1}^{N_{L_i}} \alpha_{ij} C_{ij} \Big] \tag{9.1}$$

where

- N_{SAS} is the total number of SASs in the investigated area;
- N_{L_i} is the number of loads controlled by the i-th SAS;
- α_{ij} is a binary variable resulting from the solution of problem (9.1). Its meaning is as follows: it is 0 if the load j connected to the i-th SAS is to be disconnected to make the islanded operation feasible, 1 in case it remains connected;
- C_{ij} is the load j connected to the i-th SAS.

In the following, this model will be referred to as **Model 1**.

Solving Model 1, due to the particular problem studied, multiple solutions can be found for the same load level; in that case, it should be better to select the solutions where larger generation and regulating resources (voltage support and larger inertia, and consequently expected better dynamic response) are left in operation. Therefore, a second model, **Model 2**, is recommended, with a better objective function, which also includes the generation in the maximization of the objective function:

$$\max\Big[Load{+}Generation\Big] = \max\Big(\sum_{i=1}^{N_{SAS}}\sum_{j=1}^{N_{L_i}}\alpha_{ij}C_{ij}{+}\sum_{i=1}^{N_{SAS}}\sum_{m=1}^{N_{E_i}}\gamma_{im}P^{E}_{im}{+}\sum_{i=1}^{N_{SAS}}\sum_{k=1}^{N_{D_i}}\beta_{ik}P^{D}_{ik}\Big) \tag{9.2}$$

where:

- N_{E_i} is the number of non-regulating generators that can be controlled by the i-th SAS;
- P^{E}_{im} is the actual output of the m-th non-regulating generator connected to the i-th SAS;
- N_{D_i} is the number of regulating generators that can be controlled by the i-th SAS;
- P^{D}_{ik} is the actual output of the k-th regulating generator connected to the i-th SAS;
- γ_{im} and β_{ik} are binary control variables relevant to non-regulating and regulating generators, respectively, with the same meaning as α_{ij}.

Both the above objective functions are subject to the following set of constraints:

- **Island total regulation band**: The purpose of this constraint is to allow the island to compensate in the long-term the most likely load fluctuations with regulating generation. Such fluctuations are assumed to be proportional to the total load in operation.

$$\sum_{i=1}^{N_{SAS}}\sum_{k=1}^{N_{D_i}}\beta_{ik}D^{+}_{ik} - \sum_{i=1}^{N_{SAS}}\sum_{k=1}^{N_{D_i}}\beta_{ik}D^{-}_{ik} \geq \xi\, Load \tag{9.3}$$

  where

  - P_o is the Actual power of the k-th regulating generator connected to the i-th SAS;

- P_{max} is the maximum power of the k-th regulating generator connected to the i-th SAS;
- P_{min} is the minimum power of the k-th regulating generator connected to the i-th SAS;
- $D^+_{ik} > 0$ is the available up-band for k-th generator of i-th SAS ($P_{max} - P_o$);
- $D^-_{ik} < 0$ is the available down-band for k-th generator of i-th SAS ($P_{min} - P_o$);
- ξ is a user-defined constant that quantifies the total necessary regulating band.

- **Further constraints on up and down bands** can be considered, that can, in some cases, overlap the above constraint:
  - additional constraints on the minimum up and down band:

$$\sum_{i=1}^{N_{SAS}} \sum_{k=1}^{N_{D_i}} \beta_{ik} D^+_{ik} = D^+_{tot} \geq \tau\, Load \tag{9.4}$$

$$\sum_{i=1}^{N_{SAS}} \sum_{k=1}^{N_{D_i}} \beta_{ik} D^-_{ik} = D^-_{tot} \leq -\tau\, Load \tag{9.5}$$

    Where τ is a user-defined constant; a couple of different real power values in MW could be specified instead of $\tau\, Load$, making the band asymmetrical.
  - additional constraints on up and down bands: these constraints determine the amount of controllable generation that can mitigate the instantaneous imbalance between load and generation that appears after the islanding and after the control actions have been applied. The purpose of this constraint is to allow that,
    * an **up** regulating band D^+_{tot} is available if, after all control actions actuation, the island load is higher than generation, and
    * a **down** regulating band D^-_{tot} is available if, after all control actions actuation, the island load is lower than generation.

$$\sum_{i=1}^{N_{SAS}} \sum_{k=1}^{N_{D_i}} \beta_{ik} D^+_{ik} = D^+_{tot} \geq \sigma\, \Delta I \tag{9.6}$$

$$\sum_{i=1}^{N_{SAS}} \sum_{k=1}^{N_{D_i}} \beta_{ik} D^-_{ik} = D^-_{tot} \leq \sigma\, \Delta I \tag{9.7}$$

    Where $\sigma > 1$ is a user-defined parameter and defines the security margin with respect to the imbalance that would appear after islanding and after the control actions determined, with:

$$\Delta I = Load - Generation = \sum_{i=1}^{N_{SAS}} \sum_{j=1}^{N_{L_i}} \alpha_{ij} C_{ij} - \sum_{i=1}^{N_{SAS}} \sum_{m=1}^{N_{E_i}} \gamma_{im} P^E_{im} - \sum_{i=1}^{N_{SAS}} \sum_{k=1}^{N_{D_i}} \beta_{ik} P^D_{ik} \tag{9.8}$$

    It is worth noticing that:

* if $\Delta I > 0$, the constraint (9.6) is satisfied by a suitable D_{tot}^{+} and the constraint (9.7) is automatically fulfilled, because D_{tot}^{-} is a negative value;
* if $\Delta I < 0$, the constraint (9.7) is satisfied by a suitable D_{tot}^{-}, while constraint (9.6) is automatically fulfilled, because D_{tot}^{+} is a positive value;

Conceptually, constraints (9.6) and (9.7) are different from (9.3), (9.4) and (9.5), because they are dealing with the short-term transient consequent to the islanding, while the constraints introduced before are more oriented to the long-term operation of the island.

The above optimization problem is a mixed-integer programming (MIP), because it involves binary variables, which can be solved by the CPLEX solver in GAMS.

9.4.1 Preliminary Test and results

9.4.1.1 Presentation of the test cases

Tests have been performed on the test system A in order to highlight:

* differences in the mathematical model (objective functions);
* the most suitable solver for the solution of the optimization problem;
* the most appropriate values of the different user-defined parameters τ, σ and ξ.

The values of the parameters above mentioned are necessary for the follow-up of the research: they actually will be chosen based on the dynamic response of the islanded system.

The test system adopted is Test System A; its main features in terms of loads and generators are described in Figure 9.2.

Communicated
Measured

SAS	Gen 1			Gen2			Load 1		Load 2		DSO1					DSO2		
	Power	D+	D-	Power	D+	D-	Power	E+	Power	E+	Power	D+	D-	E+	E-	Power	D+	D-
1							-33	3										
2	77	0	-27				-5,4											
3							-5											
4	30	0	0	103	0	-30	-23,5											
5							-1											
6							-2				-7	1	-1			-7	1	-1
7	38,3	2	-10															
8	29,6										-2,1					-2,1		

Figure 9.2: *Data of Test System A used for tests*

Figure 9.2, in particular, shows, for each SAS, generators connected, their actual production and communicated regulating bands (D^{+} and D^{-}), loads (actual consumption) and their availability to shed a part of the load (E^{+}), Distribution System Operator (DSO) resources, using the same notation.

9.4.1.2 Tests for Model 1 - Basic load model

Figure 9.3 shows a representation of the system, where all physical and logic variables are highlighted, adopting the following meaning:

* j variable corresponding to non-controllable loads;
* l variable corresponding to controllable loads;
* m variable corresponding to non-controllable generators;
* k variable corresponding to controllable generators.

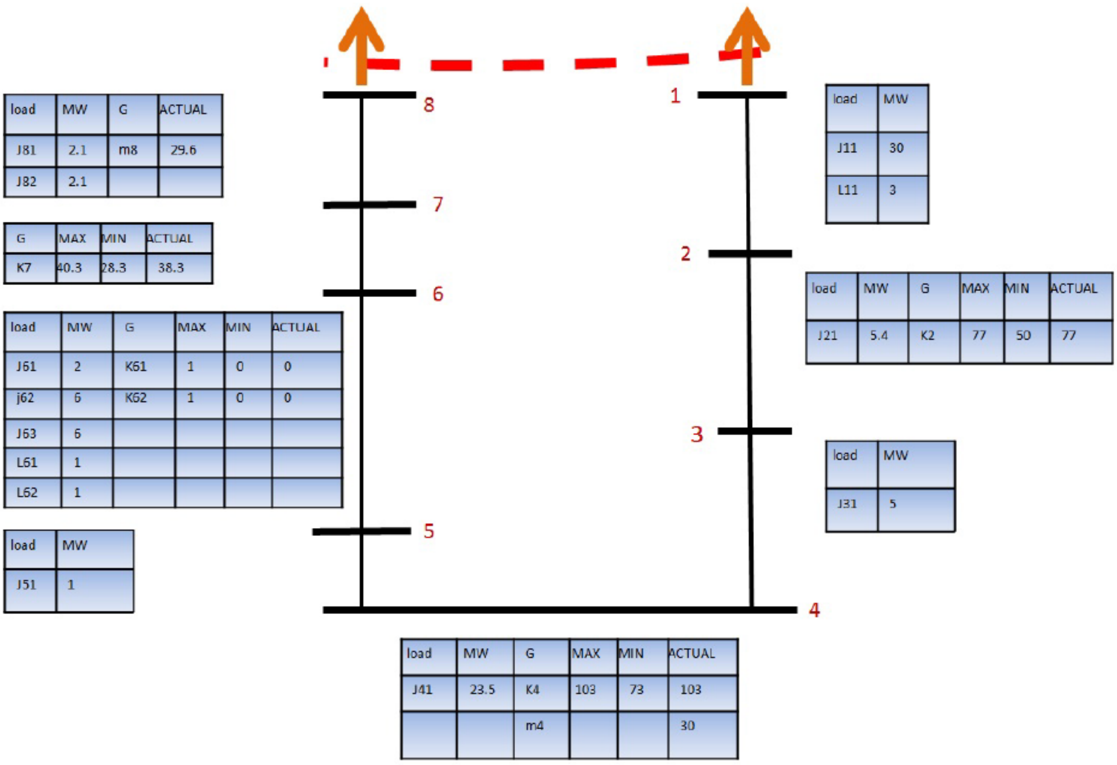

Figure 9.3: *Representation of Test System A for tests*

Adopting the above described test system, many tests have been performed in order to check the capability of the proposed procedure, and the ability of the chosen solver (GAMS, with the CPLEX solver).

In particular, 36 cases have been run on this system, to evaluate the numerical properties with respect to the parameters:

* ξ: the total up-band and total down-band are changed in the range: 0.1-0.2-0.3-0.4
* σ: the up- or down- band according to the initial imbalance are changed in the range: 1.05-1.15-1.25,
* τ: the total minimum band is changed in the range: 0.05-0.1-0.15.

The results in table 9.1 show that the procedure works fine and finds the solution when it is possible. In almost all cases, the islanding is feasible according to the assumption of steady-state conditions (this does not mean that dynamic

Table 9.1: *Results for Model 1 - Basic load model*

Case	ξ	σ	τ	NCL MW	CL MW	TL MW	NCG MW	CG MW	TG MW	ΔI MW	f_{obj} MW
1	0.1	1.05	0.05	70.1	2	72.1	42.1	26.2	68.3	3.8	72.1
2	0.2	1.05	0.05	66.9	3	69.9	30	38.3	68.3	1.6	69.9
3	0.3	1.05	0.05	41.1	1	42.1	0	38.3	38.3	3.8	42.1
4	0.4	1.05	0.05	35	0	35	0	38.3	38.3	-3.3	35
5	0.1	1.05	0.1	38	2	40	0	38.3	38.3	1.7	40
6	0.2	1.05	0.1	38	2	40	0	38.3	38.3	1.7	40
7	0.3	1.05	0.1	35.7	4	39.7	0	38.3	38.3	1.4	39.7
8	0.4	1.05	0.1	35	0	35	0	38.3	38.3	-3.3	35
9	0.1	1.05	0.15	—	—	—	—	—	—	—	NF
10	0.2	1.05	0.15	—	—	—	—	—	—	—	NF
11	0.3	1.05	0.15	—	—	—	—	—	—	—	NF
12	0.4	1.05	0.15	—	—	—	—	—	—	—	NF
13	0.1	1.15	0.05	71.5	0	71.5	30	38.3	68.3	3.2	71.5
14	0.2	1.15	0.05	69	1	70	30	38.3	68.3	1.7	70
15	0.3	1.15	0.05	40.4	1	41.4	0	38.3	38.3	3.1	41.4
16	0.4	1.15	0.05	35	0	35	0	38.3	38.3	-3.3	35
17	0.1	1.15	0.1	38	2	40	0	38.3	38.3	1.7	40
18	0.2	1.15	0.1	38	2	40	0	38.3	38.3	1.7	40
19	0.3	1.15	0.1	38	2	40	0	38.3	38.3	1.7	40
20	0.4	1.15	0.1	35	0	35	0	38.3	38.3	-3.3	35
21	0.1	1.15	0.15	—	—	—	—	—	—	—	NF
22	0.2	1.15	0.15	—	—	—	—	—	—	—	NF
23	0.3	1.15	0.15	—	—	—	—	—	—	—	NF
24	0.4	1.15	0.15	—	—	—	—	—	—	—	NF
25	0.1	1.25	0.05	70.9	0	70.9	30	38.3	68.3	2.6	70.9
26	0.2	1.25	0.05	69.9	0	69.9	30	38.3	68.3	1.6	69.9
27	0.3	1.25	0.05	37.5	4	41.5	0	38.3	38.3	3.2	41.5
28	0.4	1.25	0.05	32	3	35	0	38.3	38.3	-3.3	35
29	0.1	1.25	0.1	38	2	40	0	38.3	38.3	1.7	40
30	0.2	1.25	0.1	38	2	40	0	38.3	38.3	1.7	40
31	0.3	1.25	0.1	38	2	40	0	38.3	38.3	1.7	40
32	0.4	1.25	0.1	35	0	35	0	38.3	38.3	-3.3	35
33	0.1	1.25	0.15	—	—	—	—	—	—	—	NF
34	0.2	1.25	0.15	—	—	—	—	—	—	—	NF
35	0.3	1.25	0.15	—	—	—	—	—	—	—	NF
36	0.4	1.25	0.15	—	—	—	—	—	—	—	NF

problems will prevent actually the islanding). Only when $\tau = 1.15$ it is not possible to successfully operate the island due to the too hard constraint. This means that that parameter can be critical in some situations, at least for the studied test system A.

In Table 9.1, the following legenda is adopted:

NCL Non Controllable Load

CL Controllable Load

TL Total Load

NCG Non Controllable Generation

CG Controllable Generation

TG Total Generation

ΔI Imbalance after islanding

f_{obj} Objective function

Typically, the feasibility problem is solved in computation times around 100 ms, and this make the procedure suitable for on line applications.

9.4.1.3 Improving the load model

The proposed tests actually make an implicit assumption, i.e., that each load is controlled by only one binary variable.

Figure 9.4 shows the Basic load model, with reference to the load adopted in test system A at SAS 1. It is made by a 30 MW non controllable load (only emergency disconnection) and by a 3 MW controllable load. According to the basic load model, the feasibility procedure can decide to control the load at SAS 1 for the following values: 3 - 30 - 33 MW. In this case, the control variables relevant to each step are completely independent.

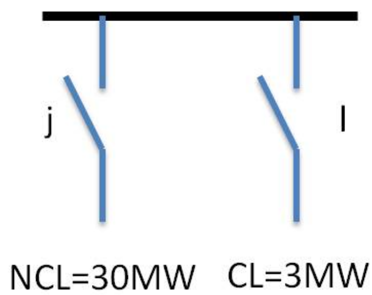

Figure 9.4: *Basic load model - SAS 1*

Actually, the above model is not realistic, as in real power systems typically the scheme of loads are as in figure 9.5: the controllable load can be shed (3 MW) and in case of emergency the total load is disconnected, including the controllable part. In the latter case, the control variables j and l are not completely independent, in the sense that if $j = 0$, then the value of l is meaningless (see also equation 9.9).

$$L = \alpha_j (NCL + \alpha_i\, CL) \tag{9.9}$$

The latter model introduces a difficulty, in the mathematical model, because it is necessary to model the load using products between the binary variables: therefore, the problem becomes a Mixed Integer Non Linear Programming (MINLP) problem. This makes it impossible to adopt CPLEX as a solver: the solver COINBONMIN is therefore adopted using the second realistic load model. The results presented in the following are relevant to that solver. The same considerations apply for the DSO models.

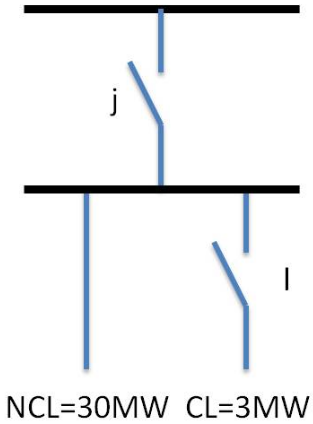

Figure 9.5: *Advanced load model*

According to the second load model, called Advanced load model, variables have been re-defined, for studying the test system A, as represented in figure 9.6. Moreover, variables relevant to DSOs have been highlighted explicitly, according to the following description:

* j variable corresponding to non-controllable loads;
* l variable corresponding to controllable loads;
* m variable corresponding to non-controllable generators;
* k variable corresponding to controllable generators;
* f variables corresponding to non-controllable loads of DSOs;
* p variables corresponding to controllable loads of DSOs;
* s variables corresponding to controllable generators for load DSO.

9.4.1.4 Tests for Model 1 - Advanced load model

The same 36 cases run adopting the advanced load model have been studied, and the results are shown in table 9.2, where total values are shortly given.

As already mentioned, this kind of maximization problem is not linear anymore and CPLEX solver is not able to solve it. Therefore, it is necessary to use COINBONMIN.

The computational time is about a couple of seconds, i.e., 16-18 times greater than the computational time of the previous model (Basic Load Model).

Table 9.2: *Results for Model 1 - Advanced load model*

Case	ξ	σ	τ	NCL MW	CL MW	TL MW	NCG MW	CG MW	TG MW	ΔI MW	f_{obj} MW
1	0.1	1.05	0.05	67.6	4	71.6	29.6	38.3	67.9	3.7	71.6
2	0.2	1.05	0.05	67.5	3	69.5	29.6	38.3	67.9	1.6	69.5
3	0.3	1.05	0.05	42	0	42.1	0	38.3	38.3	3.7	42
4	0.4	1.05	0.05	32.5	0	32.5	0	38.3	38.3	-5.8	32.5
5	0.1	1.05	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
6	0.2	1.05	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
7	0.3	1.05	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
8	0.4	1.05	0.1	29.6	2	31.6	0	38.3	38.3	-6.7	31.6
9	0.1	1.05	0.15	—	—	—	—	—	—	—	NF
10	0.2	1.05	0.15	—	—	—	—	—	—	—	NF
11	0.3	1.05	0.15	—	—	—	—	—	—	—	NF
12	0.4	1.05	0.15	—	—	—	—	—	—	—	NF
13	0.1	1.15	0.05	70.7	1	71.7	30	38.3	68.3	3.4	71.7
14	0.2	1.15	0.05	65.5	4	69.5	29.6	38.3	67.9	1.6	69.5
15	0.3	1.15	0.05	41.7	0	41.7	0	38.3	38.3	3.4	41.7
16	0.4	1.15	0.05	32.5	0	32.5	1	37.3	38.3	-5.8	32.5
17	0.1	1.15	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
18	0.2	1.15	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
19	0.3	1.15	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
20	0.4	1.15	0.1	29.6	2	31.6	0	38.3	38.3	-6.7	31.6
21	0.1	1.15	0.15	—	—	—	—	—	—	—	NF
22	0.2	1.15	0.15	—	—	—	—	—	—	—	NF
23	0.3	1.15	0.15	—	—	—	—	—	—	—	NF
24	0.4	1.15	0.15	—	—	—	—	—	—	—	NF
25	0.1	1.25	0.05	68.5	3	71.5	30	36.3	66.3	5.2	71.5
26	0.2	1.25	0.05	67.5	2	69.5	30	38.3	68.3	1.2	69.5
27	0.3	1.25	0.05	40.5	1	41.5	0	38.3	38.3	3.2	41.5
28	0.4	1.25	0.05	32.5	0	32.5	0	38.3	38.3	-5.8	32.5
29	0.1	1.25	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
30	0.2	1.25	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
31	0.3	1.25	0.1	39.7	0	39.7	0	38.3	38.3	1.4	39.7
32	0.4	1.25	0.1	29.6	2	31.6	0	38.3	38.3	-6.7	31.6
33	0.1	1.25	0.15	—	—	—	—	—	—	—	NF
34	0.2	1.25	0.15	—	—	—	—	—	—	—	NF
35	0.3	1.25	0.15	—	—	—	—	—	—	—	NF
36	0.4	1.25	0.15	—	—	—	—	—	—	—	NF

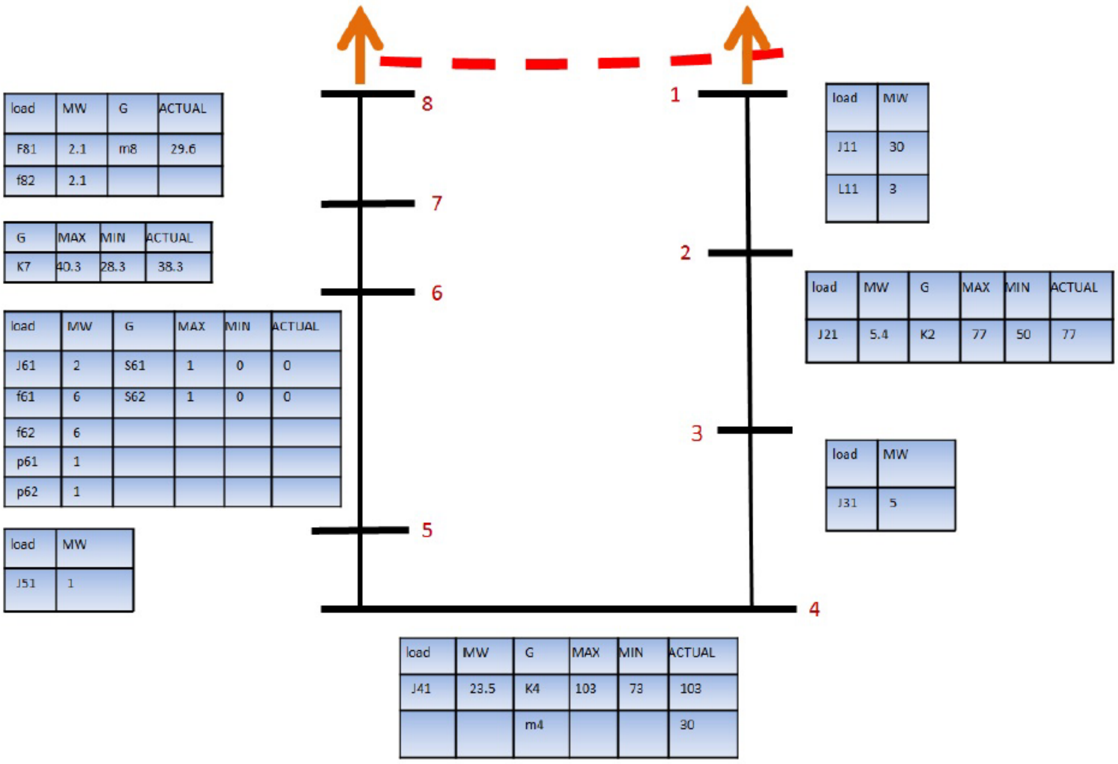

Figure 9.6: *Representation of Test System A for tests using advanced load model*

9.4.1.5 Tests for Model 2 - Basic load model

This section presents the results obtained using the MIP procedure, based on the basic load model, to solve problem 9.2. The possible drawback, adopting the optimization model 9.1, is that the same amount of load can be supplied by different combinations of generators; in that case, the preferred solution should be the one that ensures more regulating resources, i.e., more generation in operation. This is why the objective function in 9.1 has been modified to define the problem 9.2.

Actually, the results obtained are in most cases equal to the results obtained with problem 9.1, due to the data structure adopted.

However, in five cases the solutions are different. In particular, in two cases the solution of problem 9.2 is better, as expected, and, unfortunately, in three cases the solution is worse.

The solutions of these cases are shown in table 9.3, only for the different results.

The results should be compared with those in table 9.1: for example, case 7 in table 9.3 results in an increased amount of load as compared with case 7 in table 9.1. However, this actually highlights that actually the solution found by the MIP problem 9.1 is not the global optimum, but a local optimum. The same holds for Case 15.

Cases 13, 25 show another critical issue with the MIP problem 9.2: in such

Table 9.3: *Selected results for Model 2 - Basic load model*

Case	ξ	σ	τ	NCL MW	CL MW	TL MW	NCG MW	CG MW	TG MW	ΔI MW	f_{obj} MW
7	0.3	1.05	0.1	38	2	40	0	38.3	38.3	1.7	78.3
15	0.3	1.15	0.05	38.6	3	41.6	0	38.3	38.3	3.3	79.9
13	0.1	1.15	0.05	70.5	0	70.5	30	38.3	68.3	2.2	138.8
25	0.1	1.25	0.05	70.5	0	70.5	30	38.3	68.3	2.2	138.8
27	0.3	1.25	0.05	41.4	0	41.4	0	38.3	38.3	3.1	79.9

cases, not only the supplied load is less than in the corresponding table 9.1, but also the solution point is not a global optimum, as the objective function in table 9.3 is lower than the sum of the total load and generation in table 9.1.

Finally, case 27 shows that the load supplied is lower than in table 9.1, but the optimization worked properly as the objective function in table 9.3, is higher than the sum of the total load and generation in table 9.1.

This is a typical issue in the field of the optimization with discrete variables: the algorithms based on gradients and derivatives do not guarantee that the solution obtained is actually a global optimum; this drawback could be solved using Genetic Algorithms or similar tools. However, the latter methods usually take a large computation time, not suited for the proposed application.

It is worth noticing, however, that the solutions obtained by the two approaches (problems 9.1 and 9.2) are in most cases identical, and only in few cases different; in the latter cases, moreover, the solutions obtained are quite close. Therefore, both the above presented methods are to be considered quite efficient and should be considered for implementation in a prototype.

The following figures depict some of the studied cases to show which is the physical meaning of the different variables and what 0s and 1s imply on the islanded system operation.

They are relevant to case 7 (figure 9.7 for model 1 and figure 9.8 for model 2), to case 14 (figure 9.9 for model 1 and figure 9.10 for model 2), case 15 (figure 9.11 for model 1 and figure 9.12 for model 2). All figures refer to the Basic load model.

9.4.1.6 Tests for Model 2 - Advanced load model

The same type of comparison has been carried out using the Advanced load model, i.e., the MINLP problem. Also in this case, the results have been in most cases the same for problems 9.1 and 9.2.

Only in three cases, model 2 gave better results compared to model 1. These are shown in table 9.4.

In the first two cases, both the supplied load and generation are higher than in table 9.2, while in the third case the supplied load is higher but the generation is the same. This means that model 1 found a local optimum.

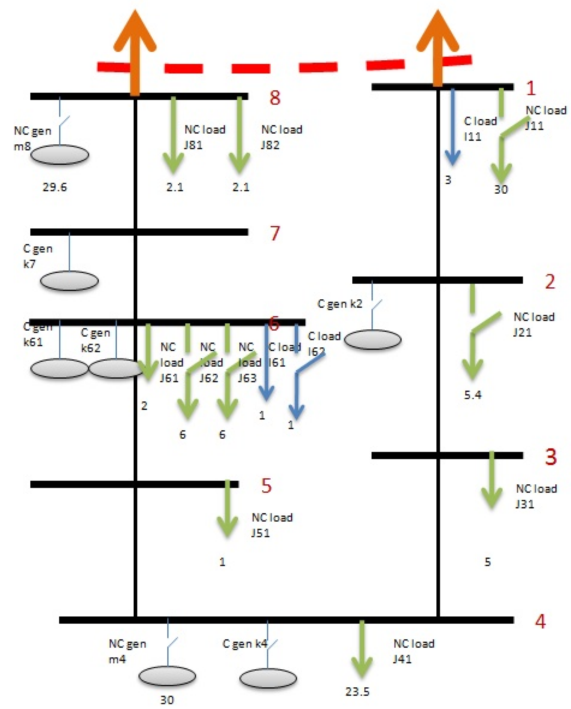

Figure 9.7: *Case 7, Model 1*

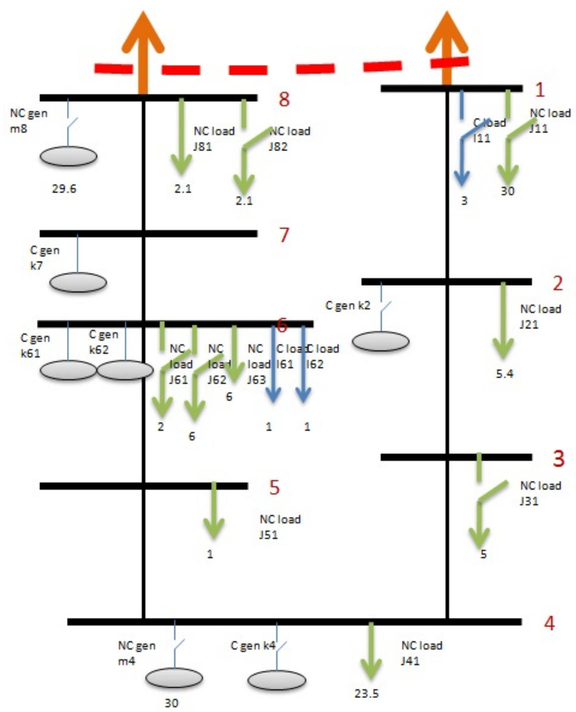

Figure 9.8: *Case 7, Model 2*

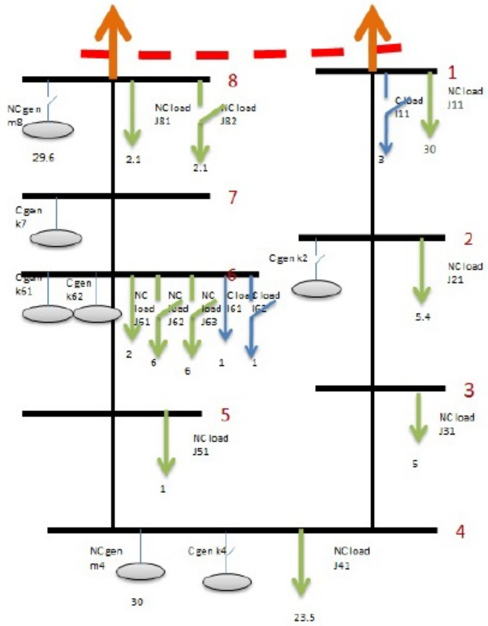

Figure 9.9: *Case 14, Model 1*

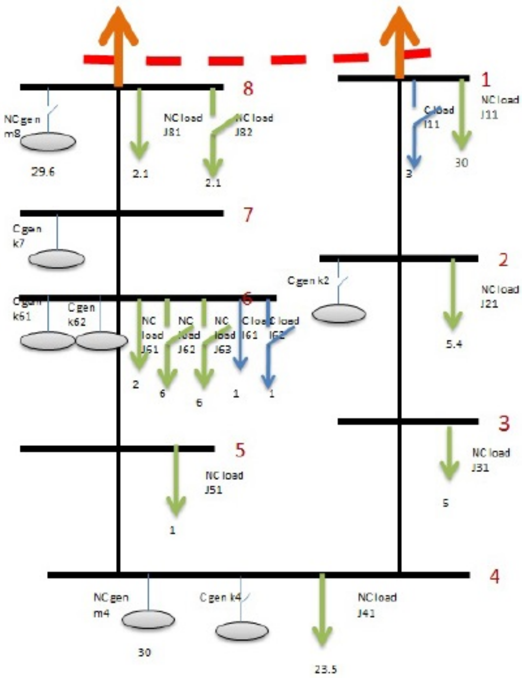

Figure 9.10: *Case 14, Model 2*

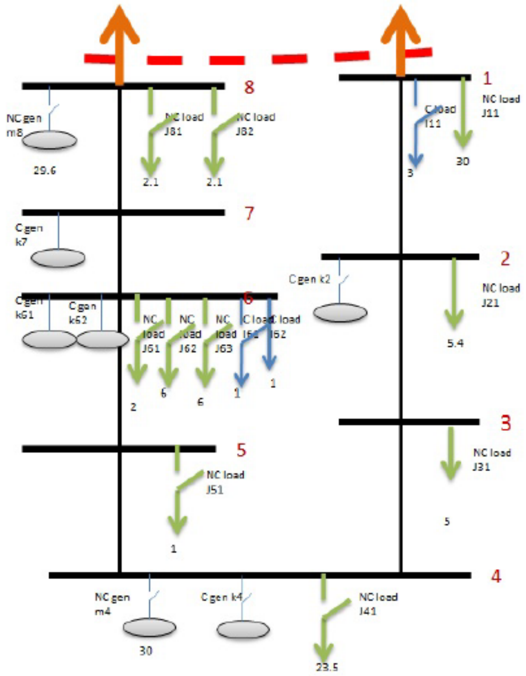

Figure 9.11: *Case 15, Model 1*

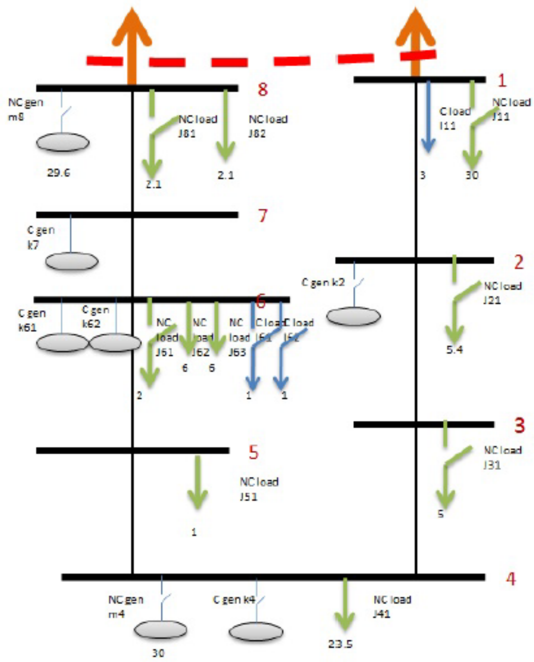

Figure 9.12: *Case 15, Model 2*

Table 9.4: *Selected results for Model 2 - Advanced load model*

Case	ξ	σ	τ	NCL MW	CL MW	TL MW	NCG MW	CG MW	TG MW	ΔI MW	f_{obj} MW
1	0.1	1.05	0.05	70.9	1	71.9	30	38.3	68.3	3.6	140.2
2	0.2	1.05	0.05	68.6	1	69.6	30	8.3	68.3	1.3	137.9
26	0.2	1.25	0.05	69.7	0	69.7	30	38.3	68.3	1.4	138

9.5 Conclusions and Future Works

9.5.1 Conclusions

This study presents an algorithm to check the possibility of islanding condition with penetration of renewable generation in a case that the certain region of subtransmission system is disconnected from the main system, to guarantee the secure islanded operation. The method involves the switching control action plan, dependent on the type of disconnection, by means of the solution of an optimization problem carried out off-line.

In this study, two load models have been considered namely basic load model and advance load model. In basic load model, each load is controlled individually which makes the problem becomes Mixed Integer Programming (MIP) problem. But for the advance load model which is more realistic, one load is dependent to another which makes the problem becomes Mixed Integer Non Linear Programming (MINLP) problem.

The ability of the proposed model is demonstrated with reference on real subtransmission system, showing the possibility of model to find feasibility of islanding.

9.5.2 Future Works

The future work may carry out to assess the above parameter values (σ, ξ, τ) by performing some dynamic simulations that can give answers on the probability that, according to the parameters chosen, the load island can survive from disconnection of the main grid. In order to perform this analysis, once the GAMS procedure is carried out, the results (in terms of generation/loads to be disconnected in case of islanding) should be transferred to DigSilent and a dynamic simulation ought to carried out. In this case, the dynamic simulations allow us to understand whether the parameters proposed are reasonable or not. Moreover, it would be possible to introduce some new constraints in order to have a secure islanding operation.

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