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Investment planning in electricity production under CO_2 price uncertainty

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ABSTRACT

The scope of this work is to investigate the effect that various scenarios for emission allowance price evolution may have on the future electricity generation mix of Greece. The renewable energy generation targets are taken into consideration as a constraint of the system, and the learning rates of the various technologies are included in the calculations.

The national electricity generation system is modelled for long-term analysis and an optimisation method is applied, to determine the optimal generating mix that minimises electricity generation cost, while satisfying the system constraints and incorporating the uncertainty of emission allowance prices. In addition, an investigation is made to identify if a point should be expected when renewable energy will be more cost-effective than conventional fuel electricity generation.

The work is interesting for investment planning in the electricity market, as it may provide directions on which technologies are most probable to dominate the market in the future, and therefore are of interest to be included in the future power portfolios of related investors.

1. Introduction

Strategic planning for the medium- to long-term expansion of the electricity generating capacity of a specific country has been an important issue in the past, when electricity markets were regulated. The major concerns in regulated markets were mainly the dependence from imported fuels, stability and reliability of the transmission grid, as well as quality and security of supply. In recent years, the deregulation of the electricity sector as well as the introduction of environmental constraints, such as the reduction of greenhouse gas emissions and targets for penetration of Renewable Energy Sources (RES) in the electricity generating mix, have added additional constraints that further complicate the procedure of planning (McGovern and Hicks, 2004). The main result of the market deregulation is that the major focus of the private investors is the generation cost, since in a competitive market it is much more probable to survive and achieve higher yields if one has lower generation cost than his competitors. Therefore, technologies with the lowest generation cost are the most advantageous for private investors. The main result of the RES introduction and the CO_2 emissions trading system is the complication of the investment decision as well as the addition of an extra expense stream for electricity generators based on conventional fuel sources, as they have to purchase the emission allowances they require. Expectations about future greenhouse gas allowance prices already influence current decision making (Dobos, 2005), especially in the electricity sector, which was one of the first business sectors affected. The effect of the allowance prices is in fact very difficult to predict, as it is severely influenced by political decisions, such as the operation of the markets, the amount of free allowances to be allocated and the emission reduction targets. Up to now, allowance prices have been characterised by high uncertainty and variability, thus making any forecasting attempt very dicey.

The scope of this work is to investigate the effect that various scenarios for emission allowance price evolution may have on the orders for new electricity generation technologies and therefore, on the future electricity generation mix of Greece. The renewable energy generation targets are taken into consideration as a constraint of the system, and the learning rates of the various technologies are included in the calculations. The methodology presented may be used for the electricity system of any country (Table 1).

2. Literature

The issue of the optimum electricity generating portfolio has long troubled researchers. Bar-Lev and Katz (1976) were among the first to introduce the portfolio analysis in the power sector. More recent research (Awerbuch and Berger, 2003; Awerbuch, 2006; Bazilian and Roques, 2008) has extended the analysis to various power expansion mixes. Mean-variance portfolio techniques have been applied in various instances, presenting also various risk measures (Fortin et al., 2008; Roques et al., 2008).

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Table 1
Notations.

Indices	Description
i	Technologies included in the study
t	Years *[2010,2050]*
Sets	
REN	Renewable technologies
CONV	Conventional technologies
Parameters	
$AI_{i,t}$	Investment annuities (€/MW$_{el}$/year)
$Cf_{i,t}$	Fuel cost (€/MWh fuel)
Cco_{2t}	Forecasted CO2 price in year t (€/ton CO_2)
$CO_{2i,t}$	Total emissions allowance cost for year t and conventional tech. i (€/MW$_{el}$)
E_i	Energy generated yearly from unitary capacity of technology i (MWh/MW$_{el}$)
$Edem_t$	Energy demand in year t (MWh)
$EGC_{i,t}$	Average levelised lifetime electricity generation cost (€/MWh)
$Emco_{2i}$	CO_2 emissions of technology i (ton CO_2/MWh$_{el}$)
$F_{i,t}$	Total fuel cost for year t and technology i (€/MW$_{el}$)
$I_{i,t}$	Investment cost per unit of capacity installed (€/MW$_{el}$)
$OMf_{i,t}$	Fixed operational and maintenance costs (€/kW$_{el}$)
$OMv_{i,t}$	Variable Operational & Maintenance costs (€/MW$_{el}$)
$Pcl_{i,t}$	Capacity of tech. i scheduled to be decommissioned in year t (MW$_{el}$)
$Pdem_t$	Peak-load demand in year t (MW$_{el}$)
$Pmax_i$	Maximum resource potential of technology i (MW$_{el}$)
$Ptot_{i,t}$	Installed capacity of technology i in year t (MW$_{el}$)
$Q_{i,t}$	Projected global installed capacity of technology i in year t (GW)
Top_i	Operational lifetime of technology i (years)
b_i	Learning rate of technology i
fav_i	Availability factor of technology i
$fcap_i$	Capacity factor of technology i
n_i	Efficiency factor of technology i
r	Interest rate

There are two main approaches in the literature, when dealing with energy portfolios and the future optimum power generation mix. The first approach mainly aims at maximising the Net Present Value (NPV) of the entire system investigated, which is usually the electricity generation sector. The NPV comprises the objective function of an optimisation problem, which is subject to an appropriate set of constraints, depending on the case examined. The optimum point determined by the optimisation problem is the power generation mix for which the system NPV is maximised, thus indicating the optimum investing timing, such as in Madlener et al. (2005), Xia et al. (2008) and Kumbaroglu et al. (2008). Inevitably, this approach entails forecasting of the future electricity prices.

The second main approach of optimising energy portfolios concerns works focusing on minimising the electricity generation cost (Porat et al., 1997). This approach has the advantage that no assumption over the future electricity prices has to be made. On the contrary, focusing on minimum generation cost implies maximising the potential for positive financial yields, irrespective of the electricity price. Equivalently, minimising the generation cost may be considered as minimising the cost to be passed on to the final consumers (Bagnall, 2004). For example, in Ref. Jaber et al. (2004), medium-range planning economics of using alternative fuel options for electrical-power generation systems in Jordan is discussed, for the period 2001–2015. The options included imported natural gas, heavy fuel oil, coal and local oil shale, which were compared using the levelised generation cost methodology. In a similar vein, the electricity generation cost in Turkey has been investigated in Ref. Akkemik (2009), focusing mainly on determining scale economies, overcapitalisation, and technological progress for past years.

Individual power-plant strategies have also been the focus of extensive research, such as in Ref. Tolis et al. (2010). However, examining only one technology without the context of the whole electricity generating sector bears the risk of ignoring some interesting alternative solutions, potentially leading to lower generation cost and, therefore, preventing the maximum benefit chances for individual players.

Mean-variance frameworks have also been proposed to address the energy portfolio planning and the optimal allocation of positions in peak and off-peak forward contracts (Huisman et al., 2009). It has been shown that optimal allocations are based on the risk premium differences per unit of day-ahead risk as a measure of relative costs of hedging risk in the day-ahead markets. In a case study (Heinrich et al., 2007), multiple objectives are confronted in portfolios under demand uncertainty in order to lead to optimal expansion solutions. The multi-objective extension is achieved by assigning cost penalties to non-cost attributes to force the optimisation to satisfy non-cost criteria, while still complying with environmental and demand constraints. The influence of the risk management has been analysed in different studies concerning either solely electricity production or multi-objective functions comprising of combined heat and power production (Huang and Wu, 2009; Svensson et al., 2009). Decision support tools have been also developed (Turton, 2008) seeking for globally optimal solutions by taking into account financial and economical conditions and constraints imposed at an international level. The impact of uncertain energy prices on the supply structures and their interaction with the demand sectors have been analysed in Krey et al. (2007).

3. Methodology

Ten different electricity generation methods have been included in the examination, almost all of them with different fuel source (as seen in Table 3). For each one of them, the best available technology has been selected. The rationale behind this choice is that all available conventional and renewable energy sources should be included in the work, apart from nuclear power, which is strategically excluded from the electricity generation mix of Greece since many years. The electricity generating cost is calculated for each year and each technology using the levelised lifetime cost estimation methodology (IEA, 2005), which is considered as one of the most important indicators for evaluating fiscal performance of power supply systems (Gökçek and Genç, 2009) in the relevant literature. According to this methodology, the levelised lifetime cost per unit of electricity generated is the ratio of total lifetime expenses versus total expected outputs, both expressed in terms of Present Value equivalent. The original methodology has been expanded to match the specific requirements of this work. This methodology has been chosen instead of traditional Net Present Value analysis, as it transforms the investments and the time series of expenditures and incomes during the lifetime of the investment to equal annuities, discounted in Present Value. Therefore, it allows fair comparison of the electricity generation cost even for power plants installed in years close to the boundary of the time-period examined, where traditional NPV analysis would fail to provide reliable results, as only part of the lifetime of the power plant would be included in the calculations.

Thus, the average levelised lifetime electricity generation cost EGC is

$$EGC_{i,t} = \sum_{n=t}^{T}[(AI_{i,t}+OMf_{i,n}+OMv_{i,n}+F_{i,n}+CO_{2i,n})(1+r)^{-t}] / \sum_{n=t}^{T}[E_i(1+r)^{-t}]$$

$$\forall i, \quad t \in [2010, \ 2050],$$
$$\text{where} \quad T = \min(t+Top_i, \ 2050). \tag{1}$$

The investment cost is calculated as a series of equal annuities, spread over the entire lifetime of the specific technology, in order to be able to perform reliable calculations also for the years t where the operational lifetime of a specific technology is longer than the remaining time period for examination. This way, only the annuities corresponding to the time span under investigation are taken into account

$$AI_{i,t} = \frac{I_{i,t}\,r}{(1-(1+r)^{-Top_i})} \quad \forall i,\ t \in [2010,\ 2050], \tag{2}$$

where the investment cost $I_{i,t}$ is calculated using the learning rate, to take into account the learning effect stemming from the projected increase in global installed capacity for each specific technology:

$$I_{i,t} = I_{i,t0}\left[\frac{Q_{i,t}}{Q_{i,t0}}\right]^{\log_2[1-b_i]} \quad \forall i,\ t \in [2010,\ 2050], \tag{3}$$

where t_0 is the reference year (for this work equal to year 2010).

The fuel cost per unit of capacity of each technology is calculated as

$$F_{i,t} = \frac{E_i}{n_i} Cf_{i,t} \quad \forall i,\ t \in [2010,\ 2050], \tag{4}$$

where the energy generated from a unit of capacity of each technology is

$$E_i = 8760 fav_i fcap_i \quad \forall i. \tag{5}$$

The cost of obtaining the emission allowances for the power plants using conventional fuel sources is calculated as

$$CO2_{i,t} = E_i Emco2_i \cdot Cco2_t \quad \forall i \in CONV. \tag{6}$$

The Operational and Maintenance cost (O&M) is distinguished into variable (OM_v—proportional to the energy generated) and fixed costs (OM_f).

3.1. The optimisation model

The optimisation problem is formed as a forward-sweeping linear programming model and is modelled and solved in Matlab®. In order to sustain linearity, so as to avoid the complexities and limitations of a non-linear optimisation problem (Rentizelas and Tatsiopoulos, 2010), a series of yearly decisions is modelled. Each yearly decision concerns the capacity of each one of the examined electricity generation technologies to be added to the current generation mix, in order to meet the electricity demand increase. Therefore, for each yearly decision, the number of variables is equal to the number of technologies examined, which are ten for the case examined in this work. The objective function of the optimisation problem is the cost of generating the excess energy required in the year examined, which is to be minimised.

$$f(x) = \min \sum_i E_i EGC_{i,t} X_i \quad \forall t$$

$$s.t. \tag{7}$$

$$Ptot_{i,t} \le P\max_i \quad i \in (wind,\ hydro,\ geothermal) \tag{8}$$

$$130\% Pdem_t \le \sum_i Ptot_{i,t} \tag{9}$$

$$Edem_t \le \sum_i E_i Ptot_{i,t} \tag{10}$$

$$\sum_{i \in REN} E_i Ptot_{i,t} \le 50\% \sum_i E_i Ptot_{i,t} \tag{11}$$

$$\sum_{i \in REN} E_i Ptot_{i,t} \ge 35\% \sum_i E_i Ptot_{i,t} t \in [2020,\ 2050] \tag{12}$$

$$0 \le X_i \le 1500 \quad i \in CONV \tag{13}$$

$$0 \le X_i \le 1000 \quad i \in REN, \tag{14}$$

where the total installed capacity for each technology and each year ($Ptot_{i,t}$) is provided by a recursive formula (15). It is equal to the installed capacity for the specific technology the previous year than the one examined ($Ptot_{i,t-1}$) plus the new generation capacity installed the year examined (X_i) and subtracting the old generation capacity that has reached its operational lifetime during the year under examination ($Pcl_{i,t}$)

$$Ptot_{i,t} = Ptot_{i,t-1} + X_i - Pcl_{i,t} \quad \forall i. \tag{15}$$

The first set of constraints (8) states the maximum potential of some renewable energy sources. In this work it has been assumed that the maximum installed capacity of wind, hydro and geothermal power must be less than the respective national potential, at all times. Constraints (9) and (10) refer to the power and energy demand. Constraint(9) ensures that the total installed generating capacity will be at least 30% greater than the peak-load demand, in order to secure uninterrupted supply of demand, even in peak-load periods. Constraint (10) requires that the energy produced will be enough to satisfy energy demand. Constraint (11) takes into account grid stability issues. The fact that most renewable energy sources cannot be dispatched when required, as they strongly depend on weather conditions, prevents them from constituting a reliable base-load solution in the long term (mainly applicable to wind parks and photovoltaics, and to some extent to hydro and biomass). Despite their short setup periods and zero fuel requirements, they often suffer from resource unavailability. Thus, unpredictable conditions might impact the stability of the national grid and the reliability of power supply. Despite the fact that there is no consensus on the maximum allowable percentage of renewable energy to secure the grid stability, scientists agree that there is currently an upper limit on renewable power penetration to the grid (Weigt, 2009). For this reason a constraint is imposed ensuring that the total energy production from RES may not exceed 50% of the total energy demand. Constraint (12) reflects the current national renewable energy targets, which require that 35% of the total electricity from year 2020 onwards will be generated by renewable energy sources. In order to facilitate the model operation, this target has been linearly shared to the years until 2020, starting from a 10% RES share for the year 2010. Constraints (13) and (14) are logical non-negativity constraints for the optimisation variables. Furthermore, an arbitrary upper limit equal to 1500 MW/year for every conventional power technology and 1000 MW/year for every RES has been applied, in order to avoid the unnatural case where only one power source is used in one year. In total, each yearly decision problem has seven inequality constraints plus the constraints for the domain of the variables.

The CO_2 allowance price uncertainty has been taken into account in this work by analysing four scenarios of price evolution. The first one (Scenario 1) assumes zero future price of allowances, which corresponds to the situation before establishment of the Kyoto protocol. This scenario is unlikely to be realised, but is included for comparison to understand how would the electricity sector evolve if no measures for emissions reduction were taken. The other three scenarios use as starting value the prevailing CO_2 price at the end of the year 2009, which was around 15 €/ton CO_2. Scenario 2 models a very low increase in future emission allowance prices, whereas Scenarios 3 and 4 model a medium (2.5% yearly) and high (5% yearly) price increase, respectively (Table 2).

Various assumptions had to be made in order to realise the model presented in this work. First of all, it has been assumed in this work that conventional-fuel electricity generators will have to purchase the full amount of the emission allowances they require for electricity generation, which means that there are no free emission allowances allocated by the government (except from Scenario 1, where all emission allowances are considered to be provided at zero cost). Furthermore, it is assumed that the renewable energy generators will not be able to trade the green certificates from the energy they generate, as the status is not the same in all countries at the moment, and it is not clear whether it will be possible to do so in the future. The potential income from trading emission allowances or green certificates should be included in the calculations, thus reducing the respective generation cost, in order to be fair, in cases where the specific installations are eligible. Another assumption is that the inflation rate has not been included in the analysis, which means that all future values used are deflated to real values. The interest rate *r* has been assumed equal to 8%. It should be noted also that no public subsidy has been assumed for the renewable energy sources, as subsidies are policies varying for each country and also within the same country with time. Therefore, this work takes into account the real electricity generation cost of all technologies, with either conventional or renewable fuel sources, as any type of subsidies are ultimately passed on to the final consumers (directly or indirectly) and finally increase the generation cost. Finally, the minimum effective scale and minimum effective capacity increase for each technology have not been taken into account in this work as constraints, to avoid over-restricting the domain of the variables. The main inputs of the model are presented in Table 3.

4. Results and discussion

The optimisation problem has been applied for the four future CO_2 price scenarios. The optimum values of the optimisation variables, which are the capacity of each of the examined electricity generation technologies to be added to the current generation mix for each year of the investigated time-period, are presented in Fig. 1. The resulting generation capacity mix is calculated by Eq. (15) and is presented in Fig. 2. Finally, the energy (electricity) generation mix is presented in Fig. 4. Concerning the yearly capacity additions (Fig. 1), initially wind power is used exclusively in all scenarios to achieve the RES penetration targets, until the year 2013. This fact indicates that wind power has the least generation cost among all RES for this time period. Immediately after this period, as wind power potential is exhausted around year 2013 for all scenarios, emphasis is given on hydro-power. Eventually, the hydro-power potential is also exhausted between the years 2033 and 2043, depending on the scenario. Geothermal power is also engaged in year 2020 for the Scenarios 1 and 2 (with zero or low CO_2 cost), whereas for the scenarios with higher CO_2 prices, geothermal power is used earlier, in year 2017. Solar power generally does not seem to be able to compete with the other RES in cost terms. It is not used until the year 2035 for Scenarios 1 and 2, whereas it is used even later in Scenarios 3 and 4 (with high CO_2 cost), with the exception of year 2014 for scenarios 2, 3 and 4. Biomass is used in very small amounts in scenarios 1 and 2 (with zero or low CO_2 cost). Interestingly, in Scenarios 3 and 4 (with high CO_2 cost) biomass is used extensively after 2020 (for Scenario 3) or 2017 (for Scenario 4), and it is even replacing conventional power sources. As far as the conventional power sources are concerned, lignite is the only fuel of choice for scenarios with zero or low CO_2 future cost. This finding is in accordance with the practice before the introduction of the Kyoto protocol requirements, when lignite was the only base-load fuel used in Greece. Scenario 3, with medium CO_2 cost favours mainly the use of coal as the future base-load fuel, apart from a small time period between the years 2017 and 2019 when lignite would be used. The scenario with high CO_2 cost leads to the use of only natural gas as the base-load fuel. Therefore, a very interesting finding is that the technology (and fuel) chosen as the future base-load actually changes depending on the estimated future CO_2 price. In each scenario, practically only one conventional fuel technology is utilised, gradually phasing out all other technologies installed. Higher CO_2 prices promote environmentally friendlier and more expensive technologies. It should be noted that during the first ten years of the analysis, almost all new capacity added is renewable, in order for the system to be able to achieve the target of 35% RES share in electricity generation. Actually, as it can be seen in Fig. 2, RES are even replacing conventional fuel capacity during this first period until the year 2020, meaning that old conventional fuel power plants that are decommissioned are being replaced by RES. This finding reveals the fact that this is a very optimistic target set for the RES share of the year 2020, as it practically entails the introduction of almost only RES sources in the electricity system for the next decade. It is interesting to note that after the year 2023–2025 for Scenarios 3 and 4, renewable energy generation reaches its upper allowable share of 50% (grid stability constraint), which means that RES are

Table 2
CO_2 price scenarios.

Year	Scenario 1: zero CO_2 price (€/ton CO_2)	Scenario 2: low CO_2 price (€/ton CO_2)	Scenario 3: medium CO_2 price (€/ton CO_2)	Scenario 4: high CO_2 price (€/ton CO_2)
2010	0	15.00	15.00	15.00
2015	0	15.17	16.97	19.14
2020	0	15.17	19.20	24.43
2025	0	15.29	21.72	31.18
2030	0	15.45	24.58	39.80
2035	0	15.59	27.81	50.80
2040	0	15.79	31.46	64.83
2045	0	15.90	35.60	82.74
2050	0	16.10	40.28	105.60

Table 3
Main inputs of the model.
Source: Kumbaroglu et al., 2008; IEA, 2005.

	Hard-coal	Oil	Natural gas	Lignite	Biomass	Solar PV	Wind turbines	Hydro-electric	Hydro pumped storage	Geothermal
Investment cost (€/kW_{el}) year 2010	1250	1150	440	1050	2200	2770	1100	1300	3400	1800
Fixed cost (O&M, insurance, etc.) (€/kW_{el})	56.4	38	18.8	35	19	30	18	3	50	32
Variable cost (€/MWh_{el})	3.2	1.6	1.6	1	0	0	0	1.5	1.5	18
Availability factor	0.75	0.85	0.75	0.85	0.85	0.99	0.98	0.98	0.92	0.7
Capacity factor	0.85	0.8	0.85	0.85	0.8	0.15	0.35	0.25	0.4	0.9
Learning rate	0.01	0.01	0.01	0.01	0.15	0.2	0.1	0	0	0
Efficiency factor	0.51	0.45	0.54	0.41	0.3	1	1	1	1	1
CO_2 emissions (ton CO_2/MWh_{el})	0.656	0.62	0.38	1.027	0	0	0	0	0	0
Operational life-time (years)	40	40	30	40	40	25	20	40	40	40

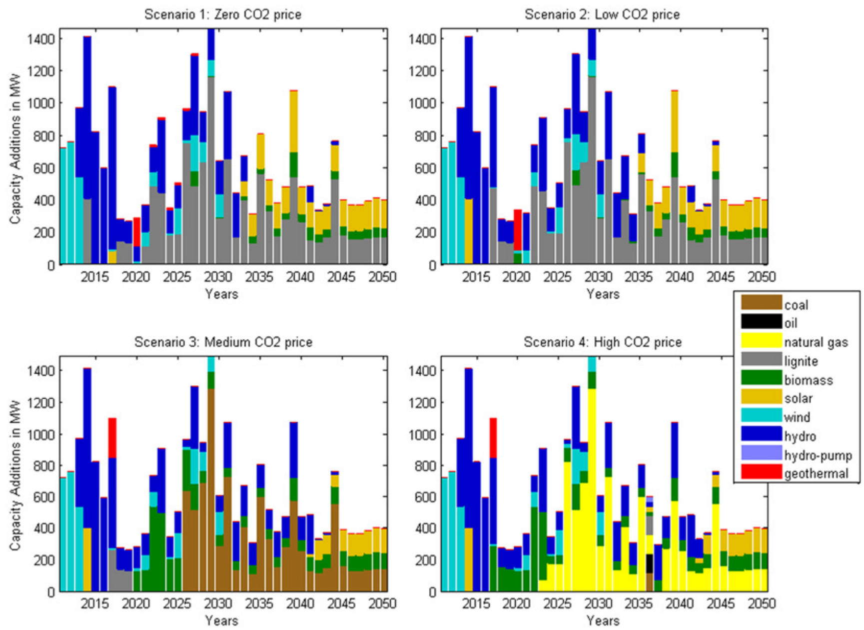

Fig. 1. Yearly capacity additions.

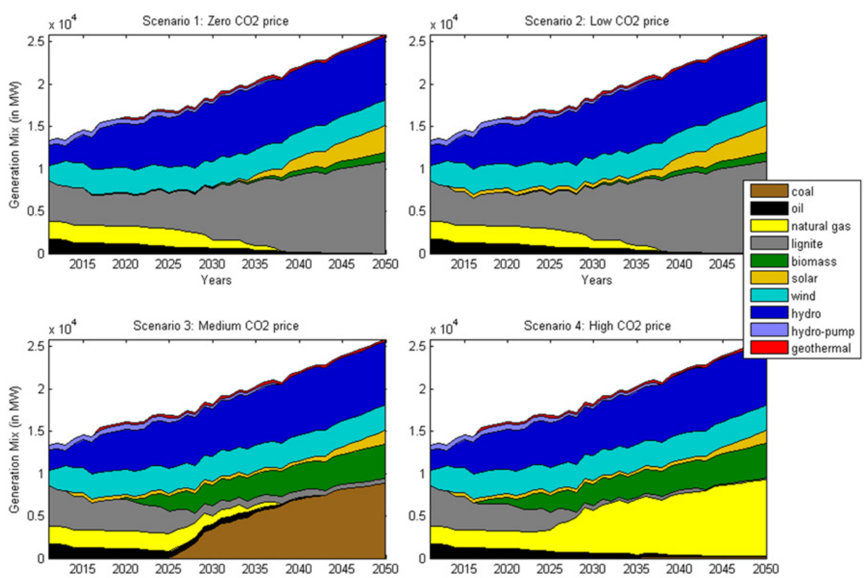

Fig. 2. Generation capacity mix.

more cost-effective than conventional power sources (Fig. 3). As a matter of fact, biomass presents an increasing trend in these scenarios, which leads to the conclusion that it could even be considered as a base-load technology alternative to the conventional power sources, as it proves to be more cost-effective (Fig. 4). In contrast, scenarios with zero or low CO_2 cost do not favour RES. In these scenarios RES penetration is limited to the minimum amount foreseen, which is 35% after the year 2020 (Fig. 4). Of course all these findings apply under the assumption made that the RES do not receive any kind of investment subsidy, and without taking into account potential incomes from trading CO_2 allowances or green certificates. In reality, if any of these assumptions does not hold, RES will be even more attractive, as their generation cost may be even lower.

In Fig. 4 a paradox may be observed, as the total energy generated declines for the first seven years, while at the same time the total installed generation capacity increases. This may be explained by the replacement of conventional energy sources, which are characterised by high capacity factors, with renewable energy sources, which have significantly lower capacity factors and, therefore, lower amount of energy generated by one unit of capacity installed. The initial decrease of total energy generated results from the fact that the initial capacity installed, using the availability and capacity factors assumed, leads to higher energy generated than the demand. From year 2017 onwards the energy generated matches the energy demand. Even without any kind of investment or electricity price subsidy, there will be a point where some RES will have lower generation cost than conventional fuel technologies, if CO_2 prices prove to be high and assuming that the learning rates will remain constant for the whole period examined. Based on numerical results of the optimisation, wind energy proves to have lower generation cost than the cheapest conventional

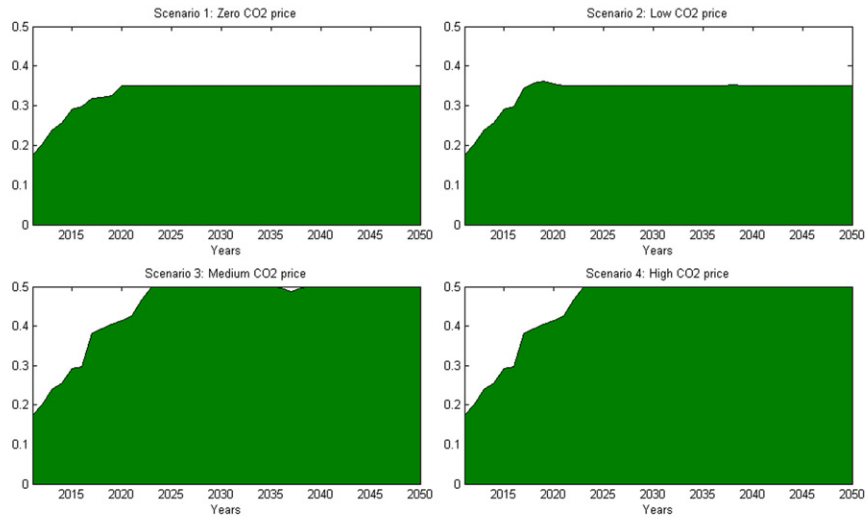

Fig. 3. RES penetration in the energy generation mix.

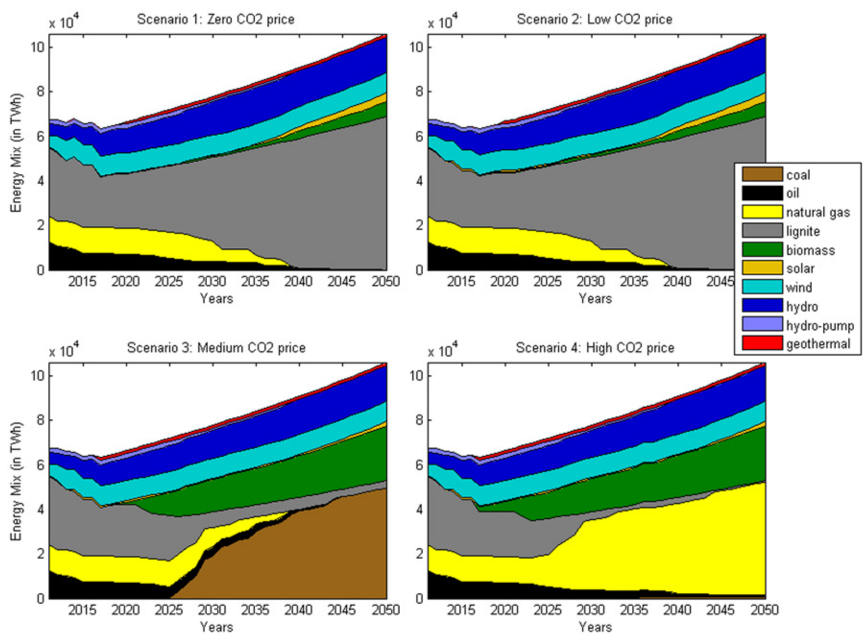

Fig. 4. Electricity mix.

power source in all scenarios with non-zero CO_2 price. The average levelised lifetime electricity generation cost EGC for Scenario 3 and for all energy generation technologies examined is presented in Fig. 5. Biomass proves to have lower generation cost than the cheapest conventional power source in Scenarios 3 and 4, but only after several years, when the effect of learning curves is stronger. Similarly, geothermal power has lower generation cost than the cheapest conventional power source in Scenarios 3 and 4, and the same applies to hydroelectric power plants in Scenario 4. Another interesting conclusion is that in order to satisfy the future forecasted energy demand, the installed generation capacity will have to be doubled between the years 2010 and 2050. However, this doubling of installed capacity will lead to only 57% increase of the energy generated, as the RES technologies introduced in the generation mix are largely characterised by low capacity factors. In Fig. 6, the Mean Electricity Generating Cost (MEGC) is presented, for the time period under examination. The MEGC has been calculated as the mean cost (averaged with the amount of energy generated) of all operational units during each year. It is interesting to note that scenarios with higher CO_2 future prices lead to higher MEGC in the future, as more expensive technologies are selected (mainly renewable) and conventional power sources need to pay more for their emissions.

It can also be concluded that an increase of the emission allowances price will inevitably lead to an increase in the price of electricity in the long term, irrespective of the selection for the least cost technologies (via optimisation) and the experience curve effect. On the contrary, if emission allowances price remains low (Scenario 2), electricity generation costs may remain at the same levels or decline slightly, whereas if the emission allowances were free (Scenario 1), one could expect a decline in electricity generation cost, mainly due to the experience curve effect.

The values of the parameters of the problem have been assumed to be deterministic. However, there is always a degree of uncertainty concerning the exact values of these parameters. For this reason, the sensitivity of the MEGC on the variation of some major

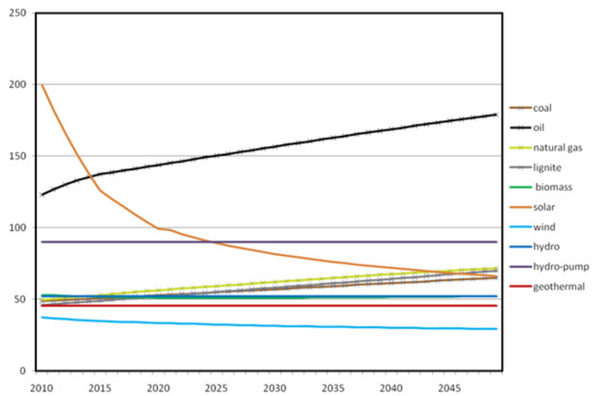

Fig. 5. Electricity generation cost for Scenario 3.

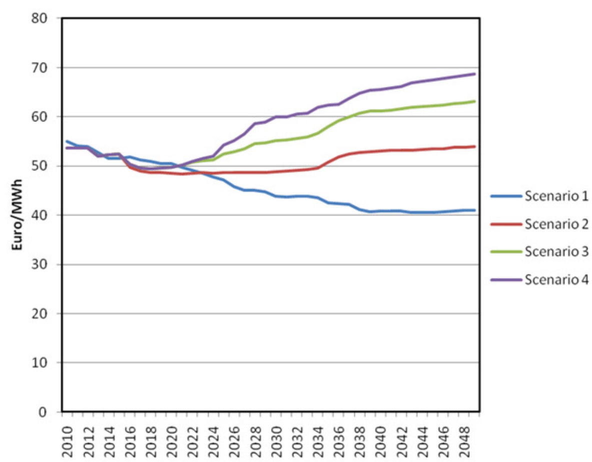

Fig. 6. Mean electricity generation cost.

parameters of the problem has been examined. The parameters analysed are the interest rate, the investment and operational cost and the fuel cost. Each of the parameters varies in the range $\pm 10\%$ of its initial value. In Fig. 7, the MEGC curves together with their respective variation on interest rate change are presented. An increase in the interest rate leads to an increase of the MEGC. It should be noted that the resulting generation mix is different for each of the various parameter values examined, which explains the fact that the variation presents significant differences among the four scenarios. However, any change in the values of the interest rate parameter shifts the MEGC curves towards the same direction for all scenarios; therefore, preserving their ranking, at least for the results after the first decade, where the values of the range of the curves differentiate significantly.

In Fig. 8, the MEGC curves together with their respective variation on technological costs are presented. The costs include the investment and operational costs (both fixed and variable), which have been assumed to be increasing or decreasing simultaneously by the same percentage ($\pm 10\%$). An increase in the investment and operational costs leads to an increase of the MEGC. It can be observed that the effect of changing the investment and operational costs by 10% is much higher than the effect of changing the interest rate by the same percentage (Fig. 7). Therefore, the decision maker should focus on determining the investment and operational cost with greater accuracy and keep in mind that future deviation of the real investment and operational cost from the original forecasts could affect significantly the electricity generation cost.

In Fig. 9, the MEGC curves together with their respective variation on fuel cost are presented. It should be noted that the change of this parameter's value actually affects only technologies with non-zero fuel cost, which are all the conventional power sources and biomass. An increase on the fuel cost naturally leads to an increase of the MEGC. It should be noted though that in some cases, such as Scenario 3 for years between 2034 and 2050, the electricity generation cost does not change when fuel cost increases. This fact can be explained by the new electricity generation mix resulting from the optimisation model, which selects more zero-cost fuel technologies (RES) when fuel cost increases.

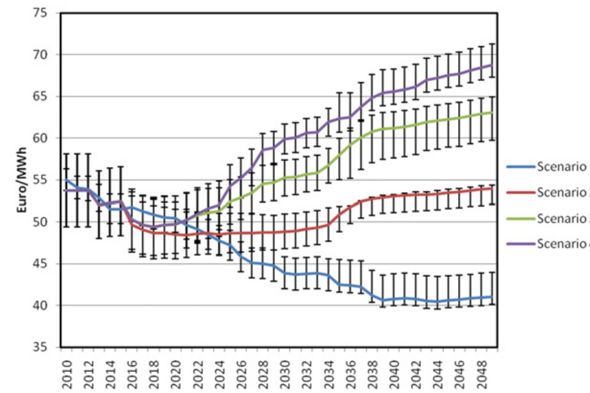

Fig. 7. Sensitivity on interest rate.

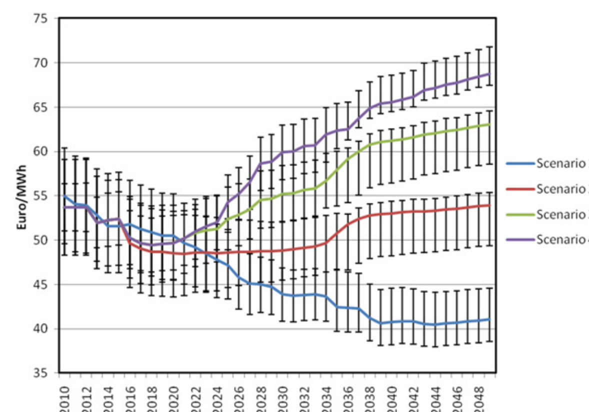

Fig. 8. Sensitivity on investment and operational cost.

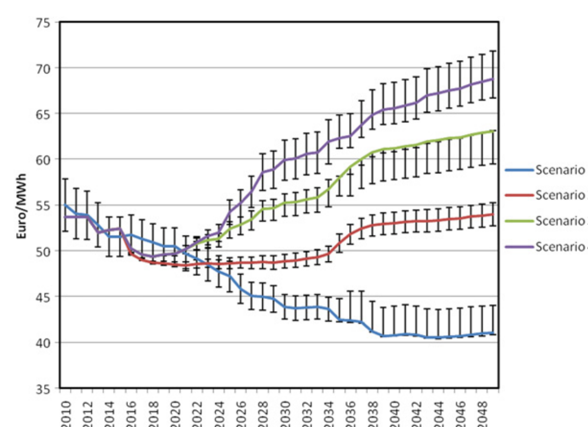

Fig. 9. Sensitivity on fuel cost.

5. Conclusions

This work presented a methodology to assist long-term investment planning in the electricity production sector. The model used is based on linear programming to define the future national electricity generation mix up to the year 2050, based on the notion of minimising the electricity generation cost, while at the same time satisfying several constraints, such as demand, reliability and emissions reduction targets. The calculation of generation cost was based on a modified version of the levelised lifetime cost estimation methodology (IEA, 2005). Additionally, the learning rates of the various technologies are included in the calculations. The aim of the work is to investigate the effect that various scenarios for emission allowance price evolution may have on the orders for new electricity generation technologies and therefore, on the future electricity generation mix of Greece. The fact that the emission allowance price has been characterised by significant fluctuations and variability enhances the importance of this work. The idea behind the optimisation performed is that one may identify the most promising fuels and technologies for each level of emission allowance price. This information could be equally useful for state authorities and private investors. One of the main findings of this work is that the conventional fuel technology with the lowest generation cost changes, depending on the future emission allowance price. Low CO_2 prices favour lignite, medium prices lead to the use of coal, whereas high prices render natural gas the most cost-efficient fuel. Furthermore, low CO_2 prices do not favour increased use of renewable energy sources, as the generation cost is almost always higher than that of the most efficient conventional fuel technology. On the contrary, medium or high CO_2 prices render some of the RES more cost-effective than conventional fuel technologies, immediately or after several years' time. In this case, the issue of determining, or finding ways to increase, the technological upper limit of RES penetration in the electricity generation mix without compromising supply quality and reliability, becomes of paramount importance. It should be noted that the RES penetration target of 35% by the year 2020 is found to be rather optimistic, as it entails that almost all new capacity installed for the next decade should be RES. If, however, energy saving measures were applied, electricity demand increase rate could be lower, and therefore, less new capacity would be required yearly. This, in turn, would allow more economic power sources to be installed, as the decision maker would be more flexible in avoiding more expensive technologies, ultimately leading to lower electricity generation cost. It would, therefore, be interesting as a further research to compare the reduction of electricity generation cost achieved, with the cost of applying the energy saving measures, as well as quantifying the emissions reduction obtained.

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