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A Mathematical Programming Approach to the Optimal Long-Term National Energy Planning

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The capacity expansion planning problem is defined as the determination of the optimal type of power generation technologies, location and time construction of new power plants in order to meet the projected electricity demand while simultaneously minimizing total cost over a long planning horizon. In this work, we present a mixed-integer linear programming (MILP) model for the optimal long-term energy planning of a national power generation system. More specifically, in order to capture more accurately the specific characteristics of the problem, the country is divided into a number of individual networks interacting each other. The solution of the model suggests the selection of the optimal power generation technologies and plant location in order to meet the expected electricity demand while satisfying environmental constraints in terms of $CO_{2\ \mathrm{emissions}}$. Furthermore, the imports of electricity from the grids of neighboring countries and the optimal electricity flows between domestic networks are also optimally decided. A real case study considering the Greek energy planning problem is used is to illustrate the applicability of the proposed model.

1. Introduction

The optimization of the power expansion planning is of critical importance undertaking taking into consideration multiple aspects and decision criteria. The traditional least cost electricity planning attempts to answer these questions and to indicate appropriate strategies for the management and the expansion of the electricity sector. In the past, cost minimization was the only criterion in the implementation of energy planning models. After 80’s, the environmental dimension has been taken into consideration due to the growing concern about global warming and its effects (Georgiou et al., 2011). There are various available supply technologies that can be utilized in order to satisfy the annual electricity demand of the examined power system. These supply options can be identified based on several factors, including operational characteristics, environmental impact, economic variation of the fuel used, their construction lead time as well as their lifetime (Turvey and Anderson, 1977). The fundamental question in this kind of problems is, what is the optimal mix of power generation technologies and CO_2 mitigation energy policy tools that should be selected in order to optimally satisfy the forecasted electricity demand and the environmental, reliability, financial, regulatory and other technical criteria, while simultaneously minimizing the total cost of the examined power system (Mirzaesmaeeli et al., 2010).
This work presents a spatial MILP model that aims to identify the optimal network of a power system throughout the planning horizon. The decisions determined by the model include:
1. The capacity additions of each type of power generation technology per zone
2. The optimal electricity flow rates between the domestic zones of the examined power system as well as the electricity imports from neighbouring countries.

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2. Model description

The nomenclature of the proposed model is described in Section 2.1.

2.1 Nomenclature

Indices

m: power generation technology
mren: renewable energy technologies
z,h: zone
nc: neighbouring country
t: time period

Parameters

CostInv(m): Investment cost of technology m (€/MW)
CostFOM (m): Fixed O&M cost of technology m (€/MW/year)
CostVOM(m): Variable O&M cost of technology m (€/MWh)
Impoprice(t): Price of imported electricity during time t (€/MWh)
CostET(t): Electricity transmission cost during time t (€/MWh)
CostPur(t): Carbon dioxide emission cost during time t (€/t CO_2)
initcap(m,z): Existing initial capacity of technology m in zone z (MW)
D(z,t): Electricity demand in zone z during time t (MWh)
CO2rate(m): Carbon dioxide emission rate of technology m (t CO_2/MWh)
MaxCap(t): Maximum CO_2 emissions cap during time t (Mt)
availf(m): Availability factor of technology m (0<availf(m)<1)
DF(t): Discount factor during time t
TF(z,h): Transmission efficiency of the transmission lines between zones z and h

Continuous variables

addcap(m,z,t): additional capacity of technology m in zone z during time t (MW)
C(m,z,t): total capacity of technology m in zone z during time t (MW)
po(m,z,t): total power generation from technology m in zone z during time t (MWh)
netpo(m,z,t): electricity production of technology m directly used in the same zone z during time t (MWh)
impo(nc,z,t): electricity imports from neighbouring country nc to zone z during time t (MWh)
FE(m,z,h,t): transmission of electricity produced by technology m, from zone z to h, during time t (MWh)
Emiyear(t): total annual CO_2 emissions during time t (t CO_2)

Binary variables

$$X(m,z,t): \begin{cases} 1, \text{ if existing technology m remains operational in zone z during time t} \\ 0, \text{ otherwise} \end{cases}$$

2.2 Mathematical model

The objective function of the proposed spatial deterministic model is to minimise the total cost of the electricity production system, including investment cost, fixed and variable operation and maintenance (O&M) cost, imported electricity cost, electricity transmission cost and CO_2 emission cost. The constraints of the model relate to technical and environmental issues such as electricity demand balance, power capacity accounting, Renewable Energy Technologies (RET) penetration target and a maximum allowable CO_2 emissions target (Zhang et al., 2012). The model has been formulated as a MILP problem and it is solved in GAMS (General Algebraic Modelling System) using the ILOG CPLEX 11.2.0 solver.

Objective function:

$$Cost = \begin{bmatrix} \sum_m \sum_t (InvCost(m,t) + FOMCost(m,t) + VOMCost(m,t)) \\ + \sum_t (IENCost(t) + ETTotalCost(t) + CO_2Cost(t)) \end{bmatrix} \tag{1}$$

Investment cost:

$$InvCost(m,t) = DF(t) \cdot \sum_z addcap(m,z,t) \cdot CostInv(m) \quad \forall m,t \tag{2}$$

Fixed O&M cost:

$$FOMCost(m,t) = DF(t) \cdot \sum_{z} C(m,z,t) \cdot CostFOM(m) \quad \forall m,t \tag{3}$$

Variable O&M cost:

$$VOMCost(m,t) = DF(t) \cdot \sum_{z} po(m,z,t) \cdot CostVOM(m) \quad \forall m,t \tag{4}$$

Imported electricity cost:

$$IENCost(t) = DF(t) \cdot \sum_{nc} \sum_{z} impo(nc,z,t) \cdot Impoprice(t) \quad \forall t \tag{5}$$

Electricity transmission cost:

$$ETTotalCost(t) = DF(t) \cdot \sum_{m} \sum_{z,h} FE(m,z,h,t) \cdot CostET(t) \quad \forall t \tag{6}$$

CO_2 emissions cost:

$$CO_2Cost(t) = DF(t) \cdot Emiyear(t) \cdot CostPur(t) \quad \forall t \tag{7}$$

Electricity demand balance:

$netpo(m,z,t) + \sum_{h \neq g} FE(m,z,h,t) \cdot TF(z,h) = po(m,z,t) \quad \forall m,z,t$	(8)
$\sum_{m} netpo(m,z,t) + \sum_{m} \sum_{h \neq g} FE(m,z,h,t) \cdot TF(z,h) + \sum_{nc} impo(nc,z,t) \geq D(z,t) \ \forall z,t$	(9)

Capacity accounting:

$$C(m,z,t) = initcap(m,z) \cdot X(m,z,t) + \sum_{v \leq t} addcap(m,z,v) \quad \forall m,z,t \tag{10}$$

Availability factor constraint:

$$\sum_{b} po(m,z,t) \leq availf(m) \cdot C(m,z,t) \quad \forall m,z,t \tag{11}$$

Renewable energy penetration target:

$$\sum_{mren \subseteq m} \sum_{z} po(mren,z,t) \geq 0.40 \cdot \sum_{m} \sum_{z} po(m,z,t) \quad \forall t \in [2020, 2030] \tag{12}$$

CO_2 emissions balance:

$$Emi_{t}^{year} = \sum_{m} \sum_{z} po(m,z,t) \cdot CO2rate(m) \quad \forall t \tag{13}$$

$$Emi_{t}^{year} \leq MaxCap(t) \quad \forall t \tag{14}$$

Additional constraints and cost components, not presented in this paper due to space limitations, include domestic and imported energy resource cost, transportation and storage cost of fossil energy resources, operational constraints concerning power capacity, electricity production, import and transmission limits, resources availability and management constraints as well as a number of logical constraints.

3. Problem description and relevant data

The proposed model has been tested on the Greek interconnected power system. The Greek power system consists of lignite, natural gas, oil, hydro, wind and solar power plants, having a total installed capacity of 15,407 MW, as it is shown in Table 1.

Table 1: Existing installed capacity in the interconnected Greek power system

Energy source	Installed capacity	
	MW	(%)
Lignite	4,928	32.0
Natural gas	4,556	29.6
Heavy fuel oil (HFO)	730	4.7
Hydro	3,017	19.6
Wind	1,452	9.4
Solar	724	4.7
TOTAL	15,407	100.0

Table 2 refers to the economic data of the new candidate power plants. It is noted that the fixed and variable O&M costs are the same for both existing and future power plants. The studied period is that from 2012 to 2030. The investment cost of all power generation technologies is assumed to remain stable throughout the planning horizon except that of PVs, following a decreasing rate, since they comprise a relatively mature technology in the Greek power market. Thus, beginning from 2,800,000 €/MW in 2012, it decreases to 1,450,300 in 2020 and shrinks to 675,508 €/MW in 2030 (Hellenic Ministry of Environment, Energy and Climate Change).

Table 2: Economic data of candidate new units

Power unit	Fixed O&M cost	Variable O&M cost	Investment cost	Commissioning time
	(€/MW)	(€/MWh)	(€/MW)	(y)
New Lignite	21,653.8	2.500	2,000,000	4
New Natural Gas Combined Cycle	9,200.0	3.500	700,000	3
New Natural Gas Open Cycle	8,284.6	3.500	450,000	2
New Large Hydro	10,715.4	1.915	1,900,000	7
New Wind	23,830.8	0.000	1,300,000	1
New Solar	9,184.6	0.000	2,800,000	2
New Biomass	50,684.6	5.276	2,700,000	4
New Geothermal	129,484.6	0.000	5,000,000	4

Concerning the CO_2 emission price, it is taken as equal to 20 € per tonne CO_2 in 2012 and increases with an annual rate of 4%, reaching to 48 € per tonne CO_2 in 2030. Regarding the price of imported electricity, it is assumed that it starts from 70 € per MWh in 2012, rises to 89 € per MWh in 2020 to reach to 119 € per MWh in 2030, i.e., it increases with an annual rate of 3 %. Finally, the maximum allowable CO_2 emission cap begins from 41.74 Mt in 2012, declines to 36.73 Mt in 2020 to reach to 31.3 Mt in 2030. The total quantity of CO_2 emissions allocated from the Greek government to the existing thermal units operating in the Greek power system for the period 2008-2012 were 41,739,165 t CO_2/y. In 2020, the CO_2 emissions should not exceed 10 % over the corresponding CO_2 emissions of 1990, which means that an annual decrease of around 1.5 % is required in order to meet the target for the period 2013-2020. There is no information concerning the CO_2 emissions level for the period 2021-2030, so it is assumed that the CO_2 emissions during that period follow the same trend with the previous period (2013-2020) and they annually decrease by a linear factor of around 1.5 %. As far as the electricity demand is concerned, the forecast used in this study has taken into account the severe economic crisis and the expecting decrease in the future electricity consumption of the country. Thus, beginning from around 50 TWh in 2012, it is assumed that the demand decreases by 2.5 % annually for the period 2012-2014 as a consequence of the economic recession. For the period 2015-2021, a significant demand growth of 6 %/y is assumed. During the latter part of the studied period, 2022-2030, it is assumed a modest growth in electricity demand, growing at a medium annual rate of 1.1 % and reaching around 83 TWh in 2030. It should also be noted that the availability factor, represented by the parameter availf(m), takes into account the intermittent availability of wind and solar plants.

4. Results

The general picture, as illustrated by the results, indicates a trend shift regarding the structure of the power generation mix. The dominant fossil fuelled power generation technologies (lignite) are gradually displaced by cleaner and environmentally friendlier technologies such as natural gas and RET, mainly wind turbines. Figure 1 shows that the lignite units account for approximately 51 % of the total electricity generation and imports in 2012 (26 TWh), fall to around 35.6 % in 2020 (24.7 TWh) and shrink to the low 19.8 % in 2030 (17 TWh). Natural gas units, as shown by the results, will play a balancing role in order to bridge the gap between a fossil fuel dominant power generation mix and a low emissions power generation mix. Thus, from approximately 26.6 % in 2012 (13.7 TWh), they account for approximately 37.3 % in 2030 with electricity production of almost 32 TWh. Regarding RET, hydroelectric units maintain a constant rate of approximately 10 % in 2020 to result in 8.3 % in 2030. Wind parks report the largest increase, since from 7.3 % in 2012 (3.8 TWh), they account for around 20.4 % in 2020 (14 TWh) and 25.7 % in 2030 (22 TWh), representing the second largest power generation contributor in the system. Finally, solar plants almost double their share in electricity generation, from 2.1 % in 2012 (1.1 TWh) to almost 4.8 % in 2030 (4.1 TWh). Their rate remains relatively low because this power technology is characterized by low availability.

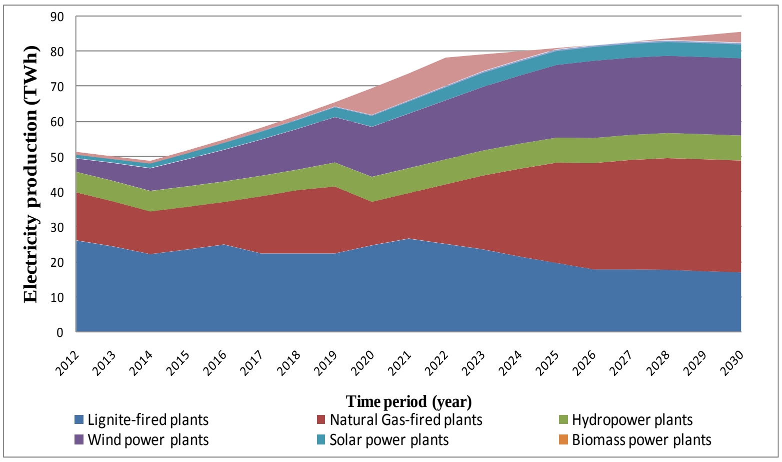

Figure 1: Electricity production mix (TWh)

The remainder, approximately 0.6 % in 2030, is distributed among the new geothermal and biomass units, while electricity imports account for 3.2 % on average during the period 2012-2030. Figure 2 highlights typical trade-off between total cost and environmental impact. The more the CO_2 emissions, the lower the overall cost of the power system and vice versa. It can be observed that the environmental policy of low CO_2 emissions proves to be more costly than operating the system with conventional lignite-fired units. The Figure shows the optimal cost for any desired level of emissions CO_2. It is noted that as we move from a high level of emissions target towards lower levels, the cost increase is not as sharp as it would be in the case in which the starting point was quite lower. For instance, the increase in the cost to move from 650 Mt of CO_2 to 590 Mt, i.e., a decrease of 9.2 % in CO_2 emission level, is approximately 330 M€ over the period considered. As the target level of emissions leads to lower CO_2 emissions, the cost increases at a greater rate. Thus, in order to reduce emissions from 660 Mt to 350 Mt an extra amount of 3.78 billion € is needed and to 300 Mt, an additional amount of 5.62 billion €.

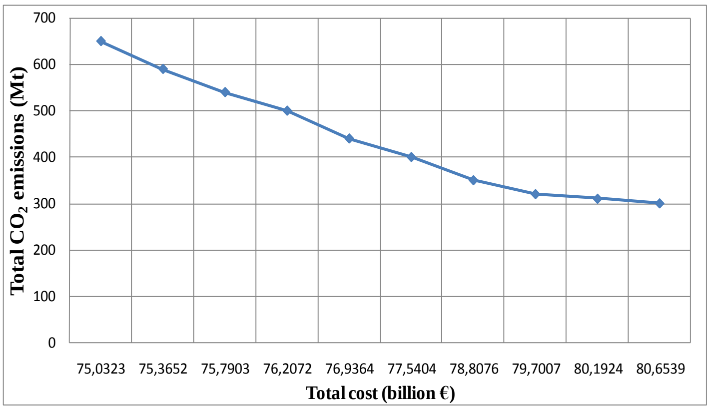

Figure 2: Trade – off between total cost and CO_2 emissions

5. Conclusions

This work presents a multi period, MILP, long term energy planning model in to order to minimize the total cost of a power system by determining the optimal mix of the power generation technologies, the capacity, the time construction and the location of the future power plants. It also suggests the optimal electricity production while simultaneously satisfying the electricity demand and several environmental constraints. The results indicate that the Greek power system is in the period of transition from the dominant lignite-fired power generation to a low-carbon power generation profile in which RET play an increasing role. The model also demonstrates typical trade–offs between the total cost of the power system development and the environmental impact, expressed in terms of CO_2 emissions. In summary, the developed model highlights the importance of comprehensive national energy planning approach and can provide the policy makers with a powerful planning tool towards the design of a low, even zero carbon economy.

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