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A real options evaluation model for the diffusion prospects of new renewable power generation technologies

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Abstract

This study presents an investment planning model that integrates learning curve information on renewable power generation technologies into a dynamic programming formulation featuring real options analysis. The model recursively evaluates a set of investment alternatives on a year-by-year basis, thereby taking into account that the flexibility to delay an irreversible investment expenditure can profoundly affect the diffusion prospects of renewable power generation technologies. Price volatility is introduced through stochastic processes for the average electricity price and for input fuel prices. Demand for peak-load capacity is assumed to be increasingly price-elastic, as the electricity market deregulation proceeds, and linearly dependent on the extent of market opening. The empirical analysis is based on data for the Turkish electricity supply industry. Apart from general implications for policy-making, it provides some interesting insights about the impact of uncertainty on the diffusion of various emerging renewable energy technologies.

Keywords: Dynamic programming, Investment planning, Renewable energy technology diffusion, Real options, Learning curve, Turkey

1 Introduction

The adoption and diffusion of new renewable energy technologies (RETs) is subject to developments that bring down unit generation costs to a level where these technologies can actually compete with conventional technologies. Such developments can be conveniently represented by learning curves, which indicate the exponential reduction in the unit cost (e.g. measured in $ per MW of installed capacity) that can be expected as their cumulative production volume increases (e.g. IEA, 2000). Prospects for the diffusion of RETs, however, are also affected by the high level of uncertainty that characterizes liberalized electricity markets (esp. regarding the price of and demand for electricity), and the way investors evaluate investment options under uncertainty. Both of these last-mentioned features call for the use of more sophisticated valuation techniques than traditional net present value (NPV) calculations. When dealing with (irreversible) investments in physical assets, real options theory (Dixit/Pindyck, 1994; Trigeorgis, 1996; Schwartz/Trigeorgis, 2001) offers a useful approach for the appreciation of uncertainty over time. A main feature of the real options approach is the accounting for the value inherent in the flexibility to delay an irreversible investment into the future. This 'value of waiting' becomes particularly important in the context of new renewable energy technologies, as these are often modular, require relatively short construction times, and exhibit steep learning curves. The combination of learning curves and real options modeling, therefore, provides an interesting approach to projecting the diffusion possibilities of new RETs and the implications of their diffusion for both conventional generation and the environment.

This study presents an investment planning model that integrates the learning curve information of renewable power generation technologies into a dynamic programming formulation that features real options analysis. The model evaluates investment alternatives in a recursive manner and on a year-by-year basis, thereby taking into account that the ability to delay an irreversible investment outlay can affect the prospects for the diffusion of different power generation technologies. Uncertainty is introduced for the (forecasted) input fuel prices and the (forecasted) average electricity price. The demand for peak-load capacity is modeled to be increasingly price-elastic over time, linearly proportional to the degree of market opening. Besides general policy implications, the empirical analysis, which also comprises a number of different scenario runs, provides some valuable insights into the impact of uncertainty on the diffusion of emerging RETs. The application is based on data for the Turkish electricity supply industry. Significant domestic renewable energy potentials, the ongoing market liberalization process, high pollutant emission levels, a pressing need for the further expansion of electricity generating capacity, and the currently still very low share of new RETs (less than 0.3% of total electricity production) are among the factors that make the Turkish electricity supply situation an especially interesting subject of study.

The remainder of the paper is organized as follows: section 2 provides the theoretical background, section 3 contains the model description, section 4 presents the empirical analysis (incl. description of scenarios, model calibration, and results), and section 5 concludes.

2 Theoretical background

2.1 The real options approach to investment planning in competitive energy markets

The restructuring of energy markets, which aims at the introduction of competition and the increase in economic efficiency, is a process that generates various risks and uncertainties thtat impact the energy sector. As the level of risk and uncertainty increases, traditional deterministic discounted cash flow (DCF) modeling approaches used for capacity investment planning need to be complemented by other, more sophisticated methods, in order to deal with the potential fluctuations in both demand and price trajectories (Dyner/Larsen, 2001; Venetsanos et al., 2002; Kagiannas et al., 2004; Olsina et al., forthcoming), among others. The real options (RO) approach to investment decision planning provides an attractive opportunity to evaluate investment alternatives in power generation in a deregulated market environment.

The idea of RO has been adopted from finance. It questions the underlying assumptions of traditional capital budgeting methods and seeks gains from deferring an irreversible investment expenditure (in contrast to a "now or never" proposition implicit in traditional NPV analysis). The RO theory, elaborated in a comparatively accessible, comprehensive and detailed fashion by Dixit and Pindyck (1994), provides a new view on investment.[1] The RO approach can be most conveniently translated into a mathematical model that can be used for analysis through a dynamic programming formulation (an alternative is contingent claims analysis). It should be noted that recently available commercial software packages, like Crystal Ball (Mun, 2002), also allow for RO modeling, thus facilitating a more widespread adoption of this still novel approach. However, the presence of non-standard constraints specific to the electricity sector (e.g. time-variant price elasticities of energy demand, non-linear cost structures, and changes in construction lead times), necessitate a tailored application, i.e. the formulation and solving of specially customized models, an example of which is presented in section 3 below.

A main feature of the RO approach is the inclusion of the possibility of delaying an investment and evaluating the value of waiting as part of the decision-making problem, which allows for a much richer analysis than if this aspect is neglected. Besides, it may help to avoid erroneous conclusions from overly simplistic investment modeling, as it has been frequently criticized (e.g. Venetsanos et al., 2002; Smith/McCardle, 1999; Awerbuch/Berger, 2003). The value of waiting can be explained as follows: If a company invests at time t, it gets the expected present value of the revenues minus the cost. In contrast, if it waits and invests at time $(t+1)$, a real option might arise that, if exercised, yields a higher net profit. In dynamic programming the sequence of investment decisions is broken up into two parts, one that addresses the immediate choice, and one that addresses all subsequent remaining decisions. For the case of a multi-period evaluation, this leads to a model formulation that can be solved recursively. The dynamic decision framework then allows to systematically compare the expected net present values from immediate investment and from waiting to invest, respectively. The ability to introduce and value the temporal flexibil-

[1] Dixit and Pindyck's seminal publication also includes a basic example that demonstrates the usefulness of the RO approach for the selection of power generation technology under uncertainty (pp.51-54; see also Kaslow/Pindyck, 1994).

ity in an irreversible investment decision represents the main distinction between real options and a conventional decision analysis based on NPV calculations.

Case studies and examples of applying the RO approach to energy industry investment problems can be found in Ronn (2003), among others. Applications of the RO approach to investment planning in the electricity sector, however, have only started to penetrate the literature in recent years and, therefore, are still very limited in number. Frayer/Uludere (2001), for instance, conduct a RO analysis on two generation assets in a regional market under volatile electricity prices. In contrast, Keppo/Lu (2003) make use of the RO approach, in order to introduce uncertainty for the electricity price, which is assumed to be affected by the investment behavior of a large producer. Botterud (2003) studies three different decision support models for long-term generation capacity investment planning in restructured electricity markets, one of which is based on RO theory (presented in Ch. 4). Botterud/ Korpås (2004) investigate the adequacy of power generation capacity in liberalized electricity markets and how/what regulatory mechanisms could ensure sufficient electricity supply, using a real options approach.

2.2 Learning curves and RET adoption

Learning curves, sometimes synonymously also referred to as 'progress curves' or 'experience curves' (e.g. Nordhaus/Van der Heyden, 1983; Dutton/Thomas, 1984; Argote/Epple, 1990), indicate the development of marginal or average unitary cost as a function of cumulative production or capacity. They are an empirical artifact rather than a theoretically well-founded concept. Observed learning curve effects can have many reasons, including technological progress, learning-by-doing, reduction in input factor prices or financing cost, or improvements in organizational efficiency. Note, however, that when empirically estimating learning rates, it can sometimes be difficult to strictly disentangle cost reductions that arise from learning effects from those caused by other impacts, such as economies of scale or economies of scope. Hence, if such additional cost-influencing factors are not appropriately controlled for, there is some danger that learning rates may actually be over- or underestimated. Commonly, *progress ratios or learning rates* are used to express estimated unit cost decreases as a constant percentage for each doubling of experience.[2]

Learning curves allow for projections of future cost reductions that are based on the extrapolation of historical trends, and in recent years have become popular also in the energy research literature and as a guide for policy-makers (IEA, 2000; Ibenholt, 2002; Junginger et al., 2005; Kamp et al., 2004; Neij, 1997, 1999; among others). In energy and climate models alike, learning curves have been employed with increasing frequency, in order to account for cost reductions due to technology-related learning and for endogenizing technological change (e.g. Messner, 1997; McDonald/Schrattenholzer, 2001; Barreto/Kypreos, 2004ab; Kypreos, 2004). At the same time, there seems to be a severe lack of discussion about the appropriateness of model specifications and estimation techniques in learning curve studies. As a matter of fact, the choice of both model specification and estimation technique can have a strong influence on the learning rate estimates obtained (Söderholm/Sundqvist, 2004). Hence we acknowledge uncertainties surrounding estimated learning curves that stem from model misspecification issues, but at the same time consider

[2] The progress ratio (*PR*) represents the rate at which costs decline each time the cumulative production (or capacity) doubles. The learning rate (*LR*) is its complement, computed as 1-*PR*. For example, if $PR = 0.8$ then costs are reduced by 20% ($LR = 0.2$) to 80% of the former level for each doubling of cumulative production or capacity.

learning curves nevertheless as a useful tool in modeling technological change in energy supply systems.

In this paper we make use of learning curves for RETs, in order to take into consideration that these technologies, due to their greater potential for cost reductions (higher learning rates, less prone to environmental taxation), are expected to successfully compete with conventional technologies at some time in the future (thus acting as "backstop technologies", cf. Heal, 1976). Such competitiveness, a prerequisite for the transition towards a more sustainable energy system, depends on the cumulative production or cumulative installed capacity, both of which are assumed to reflect the total experience gained up to a certain point in time. This allows us to model the prospects for renewable energy technology adoption and diffusion in the light of declining unit costs, which can provide useful insights to policy-makers on how to design RET promotion policies or to achieve/safeguard a desired technological composition of the power generation sector.

Recent methodological advances in the field of learning curves have used two-factor models, where in addition to 'learning-by-using' an RD&D expenditure effect on cost reductions is included as well (e.g. Kobos, 2003; Kobos et al., forthcoming). However, we are not aware at the moment of research work that has explicitly studied either learning rates in a confined (e.g. national) market, in which for some period of time no diffusion takes place (but only outside the market), or the interplay of national and "rest-of-the-world" learning rates, both of which would be useful in our modeling exercise. Recently, Junginger et al. (2005) have introduced a method to set up global experience curves, based on the reasoning that leading manufacturers typically deliver their products all over the world, implying 'global learning'. Their analysis indicates that there is a great deal of uncertainty involved in progress ratios, depending on the choice of system boundary, time frame, geographical area, local market conditions, GDP deflator, and other factors. For the case of wind farms, for example, Junginger et al. find global progress ratios ranging from 77% to 85%, which is considerably more optimistic than assumed in most of the current energy scenario studies (in the empirical analysis reported in section 4 we will also assume a less optimistic value of 90%). However, note that additional factors – such as average wind speed, land availability, grid connection, and civil works – are also of influence to local (system) learning rates.

2.3 Risk and uncertainty

Liberalization of electricity and other energy markets introduces much additional uncertainty, also and especially regarding the profitability of investments. With uncertainty, the risk profile of a particular technology influences the choice of the power generation mix, even when the technologies are commercially proven and have equal levelized costs (Awerbuch/Berger, 2003; IEA, 2003a). Table 1 shows an example of a qualitative comparison of risk characteristics for a set of selected generating technologies.

Table 1. Qualitative risk assessment for different generating technologies

Technology	Unit size	Lead time	Capital cost per kW	Operating cost	Fuel cost	CO_2 emissions	Regulatory risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High
Hydro	Very large	Long	Very high	Very low	Nil	Nil	High
Wind	Small	Short	High	Very low	Nil	Nil	Medium

Source: adapted from IEA (2003a)

New RETs for power generation (such as PV and wind power systems), on the one hand, have attractive low-risk characteristics, including short planning and construction lead times, no or low fuel cost and related greenhouse gas and pollutant emission, and low operating and maintenance costs. On the other hand, they are relatively capital-intensive – partly because the technologies are still fairly high up the learning curve, and partly because they have to concentrate a dispersed energy source. This is in contrast to, say, large hydro or nuclear power systems, which require large capital outlays, long lead times, long payback periods, and thus large investment risk. In the modeling formulation that follows, we explicitly take into account many characteristics of electricity generation technologies that allow for an explicit incorporation of their flexibility characteristics and the risks that accrue from investment.

3 Model description

The dynamic programming model formulation chosen here accommodates a period-by-period evaluation of irreversible investment alternatives under uncertainty, and thereby features a real options analysis. Structurally, it is similar to a technology adoption model recently developed for an evaluation of the economic rationality of historical power generation capacity investments in Turkey (Madlener et al., 2005). However, the "historical" model has been modified with respect to several important aspects, in order: (1) to feature a real options analysis through *a dynamic programming* model formulation; (2) to account for *construction lead times*; (3) to consider a time-variant *price elasticity of electricity* demand (assumed to increase as the extent of market deregulation and competition increase); (4) to include *non-stationary stochastic processes* for the evaluation of fuel and electricity price uncertainties; and (5) to explicitly incorporate *learning curve* information for studying the prospects for the market diffusion of new RETs. The additional capabilities of the modified model version, esp. those mentioned under (1), (3) and (4), allow for the planning of "future" investment decisions. Feature (1) highlights the fact that we have developed the earlier dynamic technology adoption linear programming model to become a dynamic technology adoption sequential decision model. Feature (2), the inclusion of construction lead times, allows to capture the impacts of delivery lags on the investment decision, which is quite essential under irreversibility and uncertainty, as pointed out by Alvarez/Keppo (2002), among others. The evaluation of the impact of stochastic price volatility, i.e. feature (4), is inevitable when studying competitive electricity markets, and has been a subject of various studies that make use of stochastic modeling (e.g. Vehviläinen/Keppo, 2003; Sahinidis, 2004). As opposed to the stationary ARMA process employed in the earlier (historical) model version, a non-stationary GBM process has been introduced in the present model, which is in accordance with empirical findings that have been reported in the literature. Pindyck's (1999) analysis on the long-run evolution of fossil fuel energy prices, for example, indicates that the state variables for fossil fuel prices follow non-stationary processes, and that a GBM process with a stochastically fluctuating drift term can be a useful approximation to the true underlying process. As the existence of a price-elastic demand can be considered a prerequisite for the success of electricity market liberalization, feature (3) is also indispensable for the representation of a gradual electricity market opening. Policy-makers are supposed to take the necessary steps and actions to increase the price elasticity of demand, which can be expected to rise as market deregulation progresses and competition is extended. In addition to these four features, we have included feature (5), which combines learning curve information and RO modeling in an empirical application as a particularly original contribution of this article, in order to explore the prospects for the diffusion of new RETs under electricity market restructuring and uncertainty. The RO approach employed in our model is in line with the theory put forward by Dixit/Pindyck (1994).

We start with the base year 2000 and evaluate the attractiveness of a set of power generation alternatives over time, under conditions of increasing competition and decreasing unitary cost (learning curves) for new RETs over the next 20 years. The year-by-year evaluation of investment options takes into account that the ability to delay an irreversible investment expenditure can profoundly affect the prospects for the diffusion of different renewable power generation technologies.

In the following model formulation, we denote variables by uppercase letters, and parameters and subscripts by lowercase letters. Capacity additions Xi,v for each technology i (indicating the plant type) of vintage v (indicating the year at which the investment decision is taken) are evaluated at each time period t to maximize the net present value, $NPVt(Xi,v=t)$, i.e.:

$$NPV_t(X_{i,v=t}) = \max \left\{ \begin{array}{l} \sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z (1+r)^{-(z-t)} L_{i,z,v=t}\, q_{i,z,v=t} \\ -\left\{ \forall \sum_i L_{i,z,v} q_{i,z,v} \geq d_z \;\middle|\; \sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z (1+r)^{-(z-t)} \left\{ L_{i,z,v=t} q_{i,z,v=t} - d_z \right\} \right\} \\ -\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} vc_{i,z,v=t} (1+r)^{-(z-t)} L_{i,z,v=t}\, q_{i,z,v=t} \\ -\sum_i fc_{i,v=t} X_{i,v=t} \\ +\frac{1}{1+r} E_t\left(NPV_{t+1}(X_{i,v=t+1}) \right) \end{array} \right\} \quad (1)$$

where p_z is the electricity price (modeled as a stochastic process, see below), r is the real interest (discount) rate, $L_{i,z,v}$ stands for the load of plant type i of vintage v in year z, $q_{i,z,v}$ denotes the corresponding duration (in hours), and d_z is peak power demand. $X_{i,v}$ is the capacity installed of plant type i in year v. The variable and fixed costs are denoted by $vc_{i,z,v}$ and $fc_{i,v}$, respectively, lt stands for lead time, and el denotes economic lifetime of the generation plant. The first two terms on the right hand side represent the revenues from selling electricity. Here, the value of power generation in excess of peak demand, d_z, is subtracted from totalrevenues, as this amount cannot be sold in the market and, therefore, does not contribute to the revenues. Obviously, the first two terms provide the value of power generated and sold as a net effect. That is,

$$\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z (1+r)^{-(z-t)} L_{i,z,v=t}\; q_{i,z,v=t} \qquad \text{if} \quad \sum_i L_{i,z,v} q_{i,z,v} < d_z$$

and

$$\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z (1+r)^{-(z-t)} d_z \qquad \text{if} \quad \sum_i L_{i,z,v} q_{i,z,v} \geq d_z$$

The next two terms on the right hand side of equation (1) stand for the present values of operation and maintenance (O&M) and investment costs, respectively. The final term is the *continuation value*, defined as the sum of NPVs, expected at time t, that accrue from investing in later time periods.[3] Here, the optimality of the remaining investment choices at vintage $v=t+1$, $t+2$, etc. is subsumed in the continuation value. Only the immediate investment de-

[3] It is the decomposition into the immediate period and the entire continuation behind it that makes the model consistent with Bellman's fundamental equation of optimality (Dixit/Pindyck, 1994).

cisions at $v=t$ are chosen optimally, and the model is solved successively using the dynamic programming technique, in order to determine the decisions for the latter periods by working *forward* (note that, similarly, one can also start at the end of the time horizon and work *backward* from a termination payoff).

Plants are assumed to be put into operation immediately after the construction lead time, $lt(i)$, has elapsed. They are operated for a duration equal to their economic lifetime, $el(i)$, which is implicitly modeled by subscript z. The first three components of the objective function (revenues, variable costs, and fixed costs) are all related to the plants for which the investment decisions are given in year t. As the model is solved successively, the resulting choices are fixed in the next year $(t+1)$ and become part of the first constraint, depicted in Eq. (2), which accounts for the electricity generation from previously installed power plants. It ensures that total power generation is sufficient to meet peak load in year z, d_z:

$$\sum_i \sum_{v=z-lt(i)-el(i)}^{z-lt(i)} L_{i,z,v} q_{i,z,v} \geq d_z(1+m) \qquad \forall\ t + lt(i) + el(i) \geq z \geq t \tag{2}$$

where m represents the reserve margin.[4] The demand for electricity is assumed to be price-elastic and determined by the function

$$d_z(p_z) = a\, p_z^{e(z)} \tag{3}$$

where a is a scale parameter, and $e(z)$ denotes the price elasticity of electricity demand, which is assumed to be time-dependent, in order to reflect an expectedly increasing price elasticity as the market opening process continues.

The second constraint ensures that output from each plant (i.e. the amount of electricity generated) does not exceed available capacity:

$$L_{i,z,v} \leq a_i X_{i,v} \quad \forall\ t + lt(i)+el(i) \geq z \geq t + lt(i)\ ,\ v \leq t \tag{4}$$

where a_i is the *availability factor* for plant type i, which refers to the percentage of time that a plant can be used, i.e. is not out of service due to maintenance or repairs. Similarly,

$$L_{i,z,v} \frac{q_{i,z,v}}{8760} \leq cf_i X_{i,v} \quad \forall\ t + lt(i)+el(i) \geq z \geq t + lt(i)\ ,\ v \leq t \tag{5}$$

where cf_i is the *capacity factor* for plant type i. It measures the productivity of the plant, comparing its actual production with the amount of power the plant would have produced if it had run at full capacity for the whole year (average energy output of the plant divided by the maximum energy output of the plant).

Uncertainty is introduced for both input and output prices, i.e. the prices of fossil fuels and electricity. The projection of electricity prices is based on a Geometric Brownian Motion

[4] Equation (2) can be considered as a make-up for a weakness of the model in representing the dynamics of a deregulated market, namely the inability of prices to adjust to changing supply/demand conditions. We believe that the actual distortion is minimal, though, as in reality the probability of outages is negligibly small. Moreover, public policy inevitably intervenes when installed capacity falls short of meeting peak load. It seems therefore a realistic assumption that subsidization occurs for the case of generation capacity shortages, as implied by Eq. (2). Such a subsidy is assumed to be technology-neutral.

(GBM), a log-normal diffusion process with the variance growing proportionally to the time interval. The price increment $D\,p_z$ is computed as

$$\Delta p_z = p_{z-1}\left(m\ \Delta z + s\ e\sqrt{\Delta z}\right) \tag{6}$$

where μ and s represent the mean drift rate and percentage volatility, respectively, Dz indicates the (discretized) time increment, and e is a standard normal random variable, $\varepsilon \sim N(0,1)$. The variability in fuel prices is reflected analogously through a GBM process for variable costs:[5]

$$\Delta vc_{i,z,v} = vc_{i,z-1,v}\left(m\ \Delta z + s\ e\sqrt{\Delta z}\right) \tag{7}$$

Finally, we integrate the learning curve information of renewable power generation technologies, in order to account for the reduction in investment cost as cumulative capacity increases. That is,

$$fc_{i,v} = fc_{i,v=2000}\,CC_{i,v}^{-li} \qquad \forall\ i, v > 2000 \tag{8}$$

where $CC_{i,v}$ is the cumulative (installed) capacity of technology i in year v. The parameter li represents the learning index, which is determined from the progress ratio PR (i.e. the rate at which the fixed cost declines whenever CC doubles) as

$$PR = 2^{-li} \tag{9}$$

This concludes our model formulation. Note that there are no country-specific constraints included in the model formulation. This means that the model can be universally adopted to other countries and regions, provided that the data necessary for model calibration are available. In the following, we describe the calibration of the model for the case of Turkey.

4 Empirical analysis

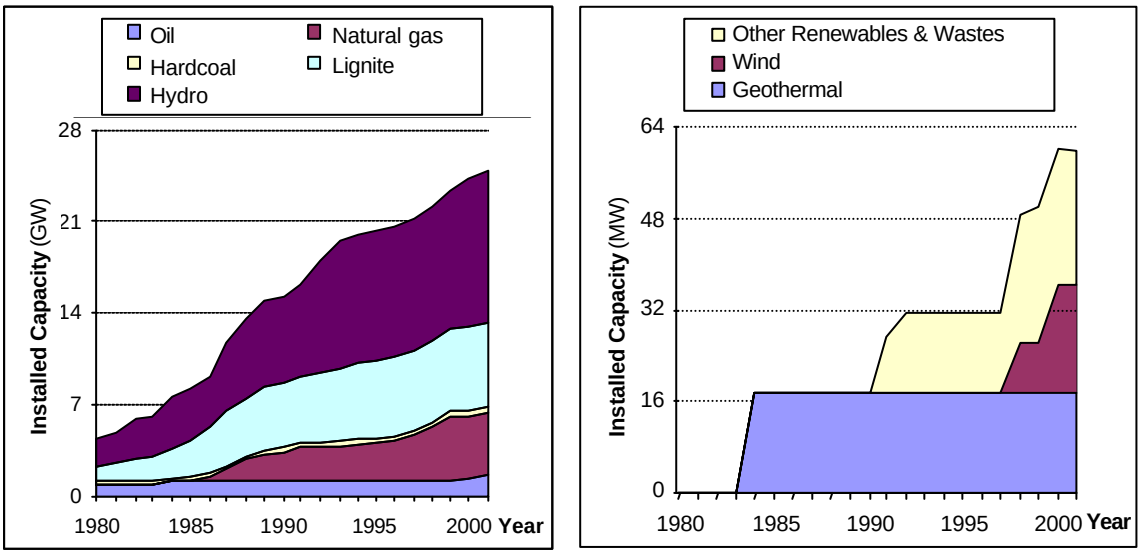
The empirical analysis is based on data for the Turkish electricity supply industry. In our opinion the case of Turkey forms a particularly interesting subject of study, because the market has been rapidly growing with an average annual growth rate of more than 8% over the last 10 years, and is currently being considerably restructured, in order to open it further for private sector participation (for further discussion see also IEA, 2001; IEA, 2005; Madlener et al., 2005). Besides, the renewable energy resources available are large, as are the yet untapped remaining potentials. Prospects for the diffusion of renewable power generation technologies in such a dynamic and expanding market are of particular interest also if environmental sustainability is to be enhanced.

[5] Energy prices are often modeled as GBM processes, whose functional values may wander far off from their original starting points. One could argue that they should somehow be related to long-run marginal production costs, and be modeled as a mean-reverting process. However, we stick to the GBM process, as due to the limited availability (scarcity) of energy resources, the marginal production costs of energy carriers might themselves wander far off from the starting values.

4.1 RETs in the Turkish electricity supply industry

Turkey is endowed with large renewable energy potentials, which taken together constitute the second-largest domestic energy resource after coal. Regarding total energy use, currently about two thirds of total renewable energy production is supplied by biomass and animal wastes (5.97 Mtoe), and one third by hydropower (2.89 Mtoe). About 0.5% of total primary energy supply (TPES; 78.4 Mtoe as of 2002) come from geothermal, wind and solar energy resources. In 2002 renewables accounted for 8.9% of TPES, of which biomass had the largest share (67.7%) (see also Table 2).

In electricity generation, renewables accounted for 26.1% (33.84 TWh) in 1999 (20% in 2001, 26% in 2002), of which hydroelectric energy was absolutely dominating (99.5%). The composition of installed hydropower capacity as of the end of year 2001 is as follows: 97.4% storage power plants (with a dam), 1.6% run-of-river power plants, and 1.0% natural lake power plants. Natural gas accounted for 40% of total power generation in 2001, coal for 31%, and oil for about 9% (IEA, 2004a; IEA, 2005). Figure 1 (left panel) depicts installed capacities in the Turkish electricity supply sector by energy source. Renewable energy sources other than hydropower account for a negligibly small share of total power generation capacity, namely 0.24% as of year 2001. A closer look at the composition of the non-hydro renewables is provided in the right panel of Figure 1. The reported geothermal capacity of 17.5 MW corresponds to that of the Kizildere plant, currently the only operating geothermal power plant of Turkey.



(a) Fossil & hydro total (b) Non-hydro renewable

Fig. 1. Decomposition of electricity generating capacity in Turkey, 1980-2001

Data source: TEIAS, 2002

Renewable electricity potentials (theoretical, technical, economic) by energy source and currently and expected future installed capacities are reported in Table 2, compiled from various sources. Of particular interest for our analysis are the economically feasible renewable energy potentials, which have been estimated at 196.7 TWh/a for biomass energy, 124 TWh/a for hydropower, 102.3 TWh/a for solar energy, 50 TWh/a for wind power, and 22.4 TWh/a for geothermal energy (Evrendilek/Ertekin, 2003).

For a developing country like Turkey, which exhibits rapidly growing energy demand levels that have to be met under severe and changing budget constraints, it is of great importance that the most cost-effective energy resources are developed first. Presently, many RETs do not fall into this category due to comparatively high power generation costs. Therefore, diffusion of new RETs is typically not included in reference energy projections for Turkey, made by means of energy modeling applications (e.g. Kumbaroglu, 2003; Conzelmann et al., 2004). Even energy policy modeling studies with particular emphasis on pollution mitigation (e.g. Arikan/Kumbaroglu, 2001; Kumbaroglu, 1997) do not consider the possibility that RETs might become economically attractive in the foreseeable future. However, together with environmentally adverse impacts caused by intensive fossil fuel use and related high levels of GHG emissions, the widespread development and use of RETs is becoming increasingly vital for sustainable development. Rapid diffusion of RETs, which in recent years has got within reach not least due to cost reductions achieved through learning and scale economies, will also help to cover the rapidly growing energy needs of Turkey.

The annual rate of electricity demand growth in Turkey is expected to increase by 8-10% until 2010. According to IEA forecasts, an increase in the installed electric generation capacity by some 30 GW until 2010 and additional 45 GW until 2020 will be needed compared to 2000 levels, equivalent to an investment requirement of approximately US$ 3-4 bn annually in generation, transmission and distribution systems (IEA, 2001). The latest IEA country report on Turkey (IEA, 2005) criticizes that commercial renewable energy applications remained limited due to insufficient promotional measures, but acknowledges recent regulatory and promotional measures as positive developments. Turkish energy policymakers indeed welcome further diffusion of RETs for the fact that it would reduce the reliance on imported fuels and at the same time enhance the country's energy supply security. A renewable energy law has passed the Turkish parliament in May 2005, which provides regulated feed-in tariffs for electricity from RES. In particular, the law foresees a guaranteed purchase price of the equivalent of the previous year's average wholesale price in Turkey (corresponding to 6.9 US-ct/kWh in 2004) for a period of seven years for electricity generated from renewable energies sources. Primarily it supports wind, small hydro and geothermal power generation, but additionally also includes references to support geothermal, solar, biomass, biogas and wave energy, and plans for targeted support of renewables.

4.2 Model calibration

Operational and cost data of existing power plants, as well as electricity price data for the period 1970-2000 are taken from the statistical yearbook of the Turkish Electricity Transmission Corporation (TEIAS, 2002). The historical data on costs and prices have been used to estimate the mean drift and volatility parameters of the GBM processes. The case of electricity prices, however, forms an exception because of the change in market structure. Because of a lack of data (financial energy markets have not been established in Turkey yet) the additional uncertainty due to competition is (arbitrarily) assumed to be 50%, a value that seems to be reasonable to us. All drift and volatility assumptions are summarized in Figures 2 and 3, which illustrate the resulting stochastic trajectories. The projections depicted in Figures 2 and 3 are plotted as the average taken from a total of 5,000 randomized simulations that have been performed.

Table 2. Renewable electricity potentials and current and expected RET installations in Turkey

Energy source	Theoretical potential	Technical potential	Economic potential	Current (2001) installation	Expected contribution / Policy goals		
					2005	2010	2020
Hydro power	49 GW [a)] 430 TWh [a)]	216 TWh [c)]	35 GW [a)] 125 TWh [a)]	11.6 GW [c)] 24 TWh [r)]	14.8 GW [d)] 48 TWh [e)]	65 [e)] - 85 TWh [f)] Goal: 100% of potential [g)]	29 [h)] - 35 GW [i)] 98 [e)] -110 TWh [f)]
Wind power	88 GW [j)] > 400 TWh [c)]	83 GW [k)] - 124 [l)] - 166 TWh [k)]	10 [j)] - 20 GW [c)] 50 TWh [c)]	18.9 MW [e)] 62.4 TWh [r)]	643 MW [d)]	0.6 [k)] - 4 GW [c)]	1 GW [k)]
Geothermal power	4.5 GW_e tot. [a)]	2.0 GW_e [m)]	22 TWh [c)]	17.5 MW [i)] 89.6 GWh [r)]	0.04 [d)] - 0.15 GW_e [g)] 22 TWh [e)]	0.3 [m,d)] - 0.5 GW_e [c)] 44 TWh [e)]	0.6 [d)] - 1 GW_e [c)] 96 TWh [e)]
Solar PV	102 TWh proven [c)]		102 TWh [n)]	0.3 MW [c)]		Goal: 40 MW_e (PV) [g)]	9 TWh [e)]
Biogas	12 [l)] - 23 TWh [e)]			5.4 MW_e [c)]	10 MW_e (Biogas-Waste) [d)]		
Biomass	197 [c)] - 372 TWh [o)]		197 TWh [c)]	91 MW [p)]		86 TWh [q)]	87 TWh [q)]
Total RET				104 TWh [d)]		25 GW [b)]	30 GW [b)]

Data sources: [a)] WEC-TNC (1996); [b)] Demirbas (2002a); [c)] Evrendilek/Ertekin (2003); [d)] Kaygusuz/Kaygusuz (2004);
[e)] IEA (2001); [f)]Kaygusuz (2002); [g)] Kaygusuz/Kaygusuz (2002); [h)] Ozgener/Hepbasli (2002); [i)] IEA (2004b); [j)] Hepbasli/Ozgener (2004); [k)] Ogulata (2003); [l)] Ediger/Kentel (1999); [m)] Acar (2003); [n)] Ogulata/Ogulata (2002);
[o)] Demirbas (2002b); [p)] IEA (2003b); [q)] Kaygusuz/Türker (2002); [r)] WEC-TNC (2003).

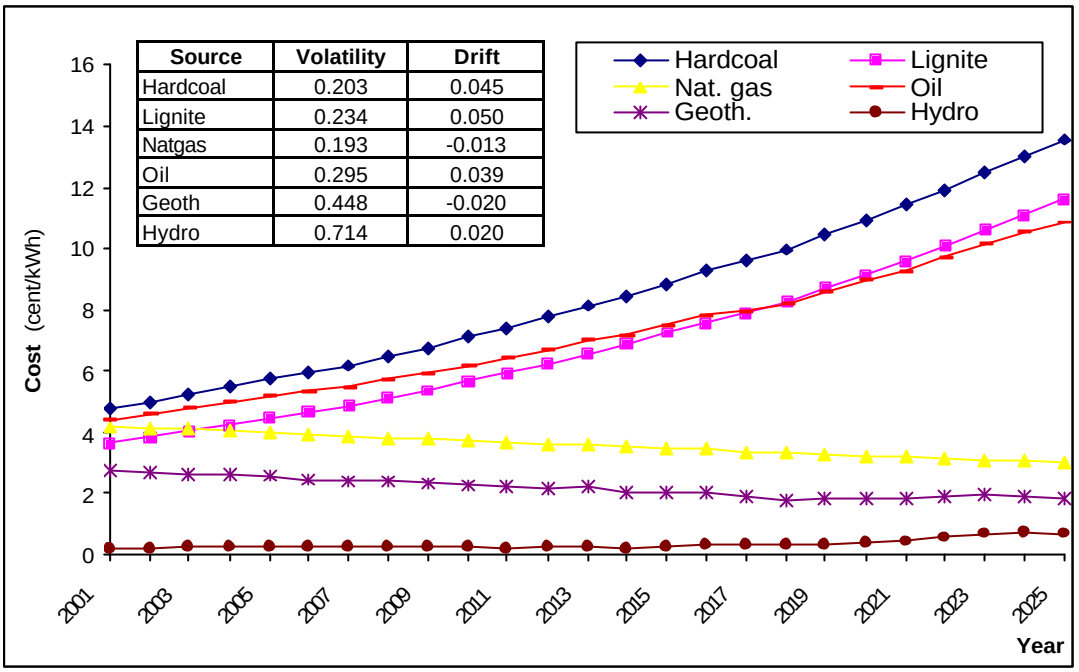
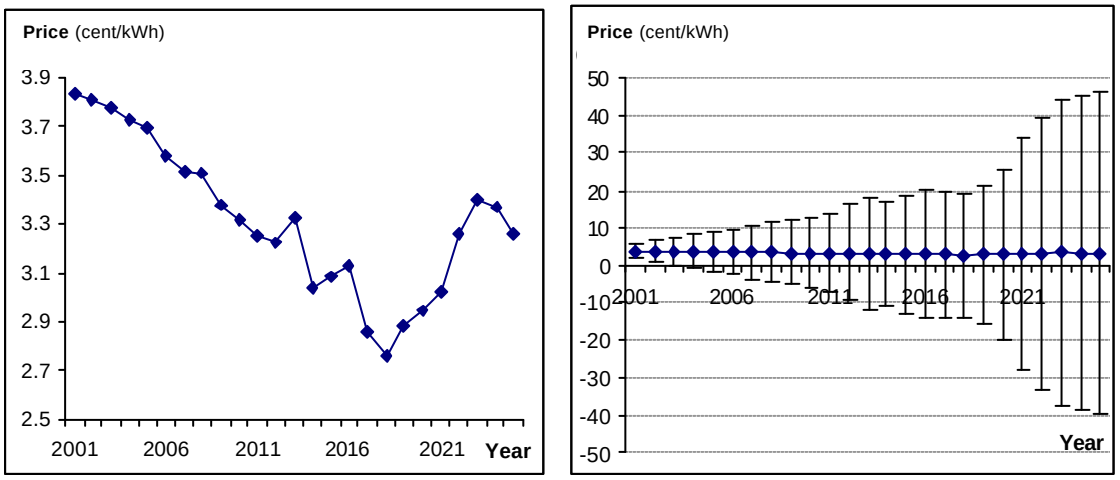


Fig. 2. Variable cost projections for existing power generation technologies, 2001-2025

As shown in Figure 2, the prices of fossil fuels except for natural gas increase. Indeed, on the one hand it is quite realistic to expect the prices of oil, lignite and hardcoal to rise in the coming decades, as these resources are getting scarcer and the substitution of alternative energy sources is accelerating. The use of natural gas, on the other hand, is becoming more and more widespread all over Europe. As a consequence, pipeline investments to develop the necessary infrastructure are expanding and the diffusion of natural gas continues, allowing for the exploitation of scale economies. Therefore, the suggested path with a slight reduction in the price of natural gas seems quite plausible. Note that this path is also in agreement with the gas price projections used in the simulation model EUGAS (Perner/Seeliger, 2004). Naturally, the variable cost components of the two existing renewable power generation options, geothermal and hydroelectricity, are significantly lower than the fossil alternatives, since no fuel costs are involved. The volatility of hydropower cost seems to be high, but this is due to the large fluctuation of historical costs, which are themselves strongly affected by fluctuations in precipitation levels.



(a) Average values (b) Standard deviations

Fig. 3. Electricity price projections, 2000-2025

The electricity price projections are depicted in Figure 3; panel (a) indicates the annual forecasts as an average of the simulations, while panel (b) depicts the standard deviations.[6] The average price trajectory seems credible, as it is in line with the electricity market restructuring experiences in a number of countries; as Turkey presently faces an electric generation capacity surplus, the price of electricity would most probably go down in a competitive market environment, at least initially.[7] In the longer term, one could expect it to approach its initial level, as has been argued, for example, by Woo et al. (2003), or even to increase, as suggested, for instance, by Bower et al. (2001), Madlener/Jochem (2001), and Olsina et al. (forthcoming). Another critical factor related to price projections is the responsiveness of electricity demand to changes in price. In electricity markets where consumers have either no choice of supplier, no ability to control their demand, or insufficient incentives to adjust their consumption, price elasticities of electricity demand can be assumed to be low, whereas in liberalized markets they can be assumed to rise (IEA, 2003c). In the literature there is still little empirical evidence on how these elasticities change as market liberalization proceeds (Schuler et al., 2004; Rosenzweig et al., 2003; Fraser, 2001; Kirschen et al., 2000; Marathe/Barrett, undated; Grohnheit/Klavs, 2000), and any generalizations should be treated with great caution because of the many particularities of electricity markets. Pilot installations of three-phase multi-tariff electricity meters have only just been started in Turkey, constituting an important concrete step towards increasing the price elasticity of electricity demand. Due to a lack of empirical evidence of what the price elasticity of electricity demand in Turkey may actually be in coming years, we have assumed linear growth for the price elasticity of electric energy, decreasing from -0.01 in year 2000 to -0.05 in 2025 for the most flexible scenario, and decreasing from -0.01 to -0.02 over the same period for the other scenarios (see below).[8]

The assumed fixed costs and availability factors for the power plants and technologies modeled as candidates for new investment are based on MARKAL-MATTER data (ECN, 2004) and summarized in Table 3. Naturally, solar PV and wind turbines have particularly low capacity factors due to the intermittence of supply based on climatic conditions with high variances. It should be noted, however, that developments in energy storage systems can increase capacity factors and decrease levelized capital costs by storing energy from high power generation periods to be utilized later as a back-up in low generation periods.

Another critical issue is the choice of an appropriate discount rate, an important topic in corporate finance (e.g. Brealey/Myers, 2005). Useful introductions on various ways to calculate discount rates (adjusted for risk and/or taxes) are provided in Taggard (1991) and Trigeorgis (1996, pp.48ff). Myers/Ruback (1992) have introduced a simple and yet robust rule for discounting risky cash flows in NPV calculations. In our analysis we assume that the risk-adjusted discount rate is constant at 5%, and refrained from trying to actually determine some risk-adjusted measure of expected return that could possibly be used as (an

[6] Note that the trend line in panel (b) represents the same price data as in panel (a), although at first glance it appears to be smoother due to the difference in scale of the y-axis.

[7] It should be noted that electricity prices fall to a level lower than fossil fuel prices implying that investment in fossil fuel based technologies would be non-economical. However, since demand needs to be met (as specified in eq. 2) they would be utilized (via technology-neutral subsidies) unless the cost of renewables reaches a competitive level.

[8] The inelastic demand at the beginning is typical for the current electricity infrastructure that largely lacks the ability of real-time metering and billing. However, policies and measures to correct for this demand-side inflexibility will increase the demand responsiveness w.r.t. price to a level, which is assumed to still remain in the inelastic region (-0.05), as the demand control and in particular substitution possibilities for electric energy for most consumers are rather limited.

improved) discount rate (see also Fama, 1977, 1996).[9] In certain cases it may be possible to construct a risk-free portfolio, to determine its expected rate of return, and to equate that with the risk-free rate of interest to be inserted instead of a simple discount rate. However, for Turkey it will take a number of years until financial energy markets will develop and methods such as the capital asset pricing model (CAPM) can be applied to determine risk-adjusted interest rates for investments in the energy sector. Note that unless very restrictive conditions are being applied, a theory for determining the "correct" value of the discount rate does not exist (Dixit/Pindyck, 1994).

Finally, the assumed learning rates for the renewable energy technologies' considered are 20% for solar PV (Turkenburg, 2000), 15% for biomass (McDonald/Schrattenholzer, 2001), 8% for offshore wind turbines (EIA, 1998), and 10% for onshore wind turbines (Seebregts et al., 1998).

Table 3. Candidate power generation technologies: costs, assumed availability, learning rates, and construction lead times

Technology	Inv. cost ($/kW)	Annual fixed O&M cost ($/kW)	Availability factor	Capacity factor	Learning rate	Construction lead time (years)
Non-renewable						
Coal FBC CHP plant	3600	144	0.80	0.70	0.05	4
Pulverized coal power plant	1488	44.4	0.75	0.80	0.05	4
Integrated coal gasification power plant	1260	64.8	0.75	0.80	0.05	4
Oil fired power plant	1032	28.8	0.75	0.80	0.01	3
Natural gas CC power plant	972	25.2	0.75	0.65	0.01	3
Gas turbine CHP plant	912	13.2	0.80	0.60	0.01	3
Lignite fired power plant	1728	44.4	0.75	0.75	0.01	4
Integrated lignite gasif. power plant	1920	37.2	0.75	0.45	0.05	4
Nuclear LWR power plant	2928	64.2	0.75	0.95	0.01	6
Renewable						
Biomass gasifier dedicated STAG (NH)	2448	240	0.75	0.80	0.15	3
Biomass gasifier SOFC*	3120	312	1.00	0.80	0.15	3
Biomass gas turbine CHP	2040	51	0.80	0.80	0.15	3
Solar PV	6000	24.6	0.90	0.15	0.20	2
Large onshore wind turbine	1140	21.6	0.90	0.25	0.1	1
Large onshore wind turbine storage	1632	26.4	0.90	0.25	0.1	1
Large offshore wind turbine storage	2340	37.2	0.90	0.25	0.08	2
Low head hydro	3420	30	0.80	0.47		10
Medium and high head hydro	2280	22.8	0.85	0.34		10
Hydro pumped storage	3420	45.6	0.92	0.40		10
Geothermal power plant	1236	31.2	0.70	0.90		2

* available starting from 2010

Source: MARKAL (ECN, 2004)

The parameters defined above make up the reference scenario. In addition, the model has been calibrated under various other scenario definitions, allowing for further explorations

[9] Note that the assumption of a constant discount rate is indeed a strong assumption in a real options modelling framework, since such a framework allows for a certain degree of managerial flexibility, thus changing the nature of risk and to a certain extent invalidating the use of a constant discount rate. In this respect our approach lies somewhere in between traditional decision analysis and real options valuation using futures and options prices for estimating risk-adjusted probabilities and the risk-free discount rate. While our approach could probably be considered as overly simplistic for an application in financial engineering, to us it seems to be an appropriate model specification for evaluating investment decisions in an electricity market currently in transition, where an investor typically encounters many different kinds of uncertainties.

of the diffusion prospects for new renewable energy technologies in the Turkish electricity market. The reference assumptions are kept as flexible as possible, in order to represent the natural evolution expected in a free market with minimum possible policy intervention. Instead of adopting the standard Business-As-Usual convention, the reference assumptions are therefore summarized under the nick *FLEX* (*representing flexibility*). Note that in scenario *FLEX* the maximum annual capacity addition limit for each technology is set at 2 GW (in order to avoid unrealistically high growth rates of certain technologies). The remaining scenarios are more restrictive, allowing for a maximum of 1 GW of additional capacity installation per technology and year (which seems to be a more realistic expectation when looking at historical capacity additions; cf. Fig. 4), and assuming a constrained increase in price elasticity from -0.01 to -0.02.

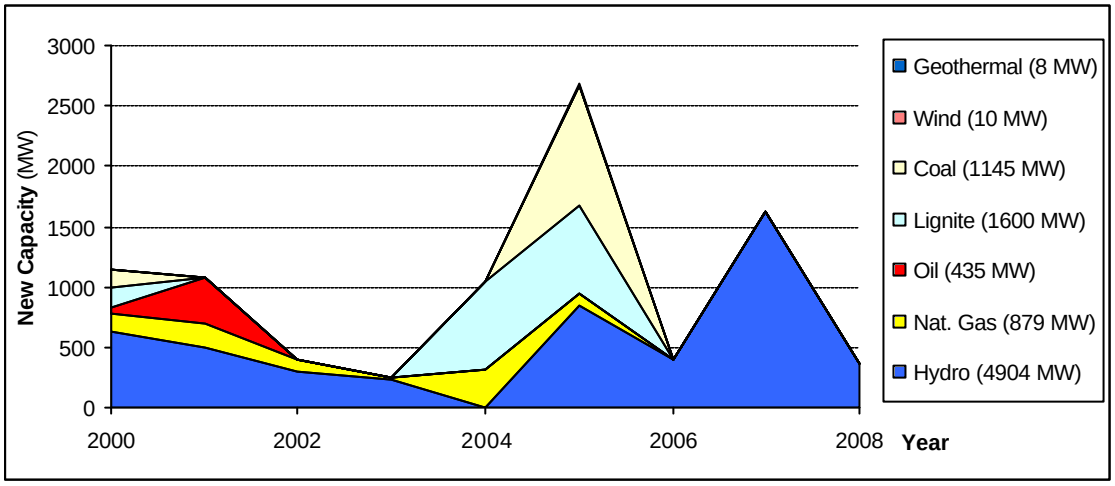


Fig. 4. Predetermined capacity additions, 2000-2008 (accumulative total in brackets)

In addition to such a *Non-Flex* scenario (*NF1*), two other non-flex scenarios are defined that include constraints on the adoption of natural gas combined cycle and wind power generation technologies. Scenario *NF2* incorporates a policy restriction that limits natural-gas-fired power generation capacity to a maximum of 40% of total installed capacity. This is a rather realistic policy constraint, as Turkey does not possess natural gas reserves; besides, limiting import dependence is among the policy priorities of the energy decision-making community. The other non-flex scenario, *NF3*, enforces all the licenses granted by the Energy Market Regulatory Authority of Turkey for wind power generation facilities (totaling 928 MW). These license acquirements are not included under the reference assumptions, as they do not represent binding agreements.[10] *NF4* includes a minimum bound on renewable energy source utilization, as required by the new renewable energy law in Turkey. Accordingly, in each year (starting from 2005), an amount equal to at least 8% of total electricity generated in the previous year has to be composed of 'new' renewable energy sources (note that the large hydroelectric power plants in Turkey do not fall under the definition of renewable sources as defined in the law). In the last non-flex scenario, *NF5*, a constant price elasticity of electricity demand of -0.02 and no technology restrictions are assumed. The scenario assumptions are summarized in Table 4.

[10] In fact, several investors have recently acquired a wind power generation license with the expectation that this renewable alternative might be subsidized by the public authority (otherwise, the licenses will remain just a piece of paper).

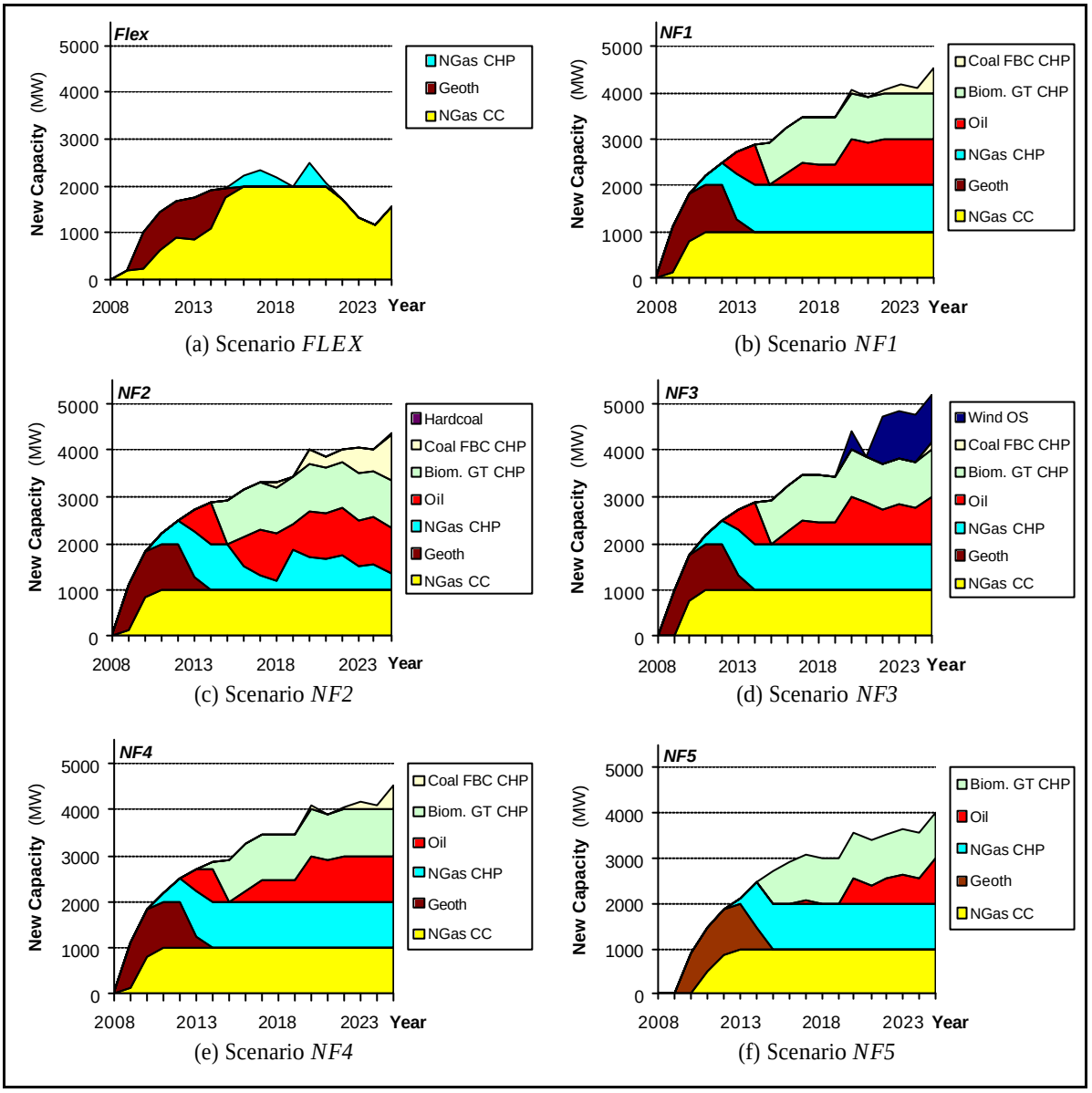
Table 4. Scenario assumptions

Scenario	Upper bound imposed on capacity addition per technology	Price elasticity (2000 → 2025)	Technology adoption restrictions
FLEX	2 GW p.a.	-0.01 ® -0.05	No restriction
NF1	1 GW p.a.	-0.01 ® -0.02	No restriction
NF2	1 GW p.a.	-0.01 ® -0.02	Natural gas capacity share = 40%
NF3	1 GW p.a.	-0.01 ® -0.02	Wind turbine licensing
NF4	1 GW p.a.	-0.01 ® -0.02	Renewable Energy Law (8% Renewables)
NF5	1 GW p.a.	-0.02 (const.)	No restriction

4.3 Model results

The model is written in GAMS and results have been obtained with the solver MINOS. A forward value iteration approach is used to solve the problem, implying 25 separate LP problems for each scenario that are solved successively. That is, starting from the base year 2000, a GAMS model is solved in each time period proceeding forward, once there is an adequate representation of the value function, such that the fundamental Bellman equation holds for each time period along the optimal path. Each LP model has a dimension of 27,612 constraints and 23,200 variables. Figure 5 illustrates the annually added capacities for each scenario and technology. Common to all scenarios, the model predicts the installation of new power plant capacities starting only after 2008. This indicates that the capacity currently available plus the plants just coming on line will be sufficient to meet the demand of the next three years (cf. Fig. 4). It is further observed that natural-gas-fired combined cycle power plants constitute the most attractive choice in all scenarios, followed by geothermal power for the first 6-8 years, and then natural gas-fired CHP. The attractiveness of gas-based technology can be attributed to their comparatively low investment and O&M costs. In scenario *FLEX*, natural gas combined cycle power plants are installed at their upper bounds (2 GW) in years 2016-2021. The reference scenario *FLEX* suggests that apart from some geothermal power capacity installation at the beginning of the projection period, for which the potential of 4,300 GW is exhausted already by 2015, there will be no investment in renewable power plants until year 2025. Imposition of a 1 GW upper bound on capacity additions does indeed make a big difference. All non-flexible scenarios include biomass gas turbine CHP plants as a second renewable power generation alternative, which comes into play after 2014 (2013 in *NF4*). In all non-flexible scenarios but *NF5*, natural gas-fired CHP capacity is added as third-most attractive option beginning in 2010 (in *NF5* by 2012) and reaching the upper bound of 1 GW after 2013 or 2014, while new capacity is employed to a much lesser (and varying) extent in *NF2*, due to the restrictions imposed on natural-gas-fired technology investments. Wind power comes into play only in scenario *NF3* (by 2019), when all license grants are enforced. Interestingly, coal-fired fluidized bed combustion CHP, playing a role in all non-flexible scenarios apart from *NF5*, seems to be more attractive than wind power by 2024, driving a fossil fuel wedge in between biomass gas turbine CHP and wind power. The imposition of the 8% renewable electricity quota foreseen in the Renewable Energy Law (scenario *NF4*) does not seem to have much impact on the diffusion of renewable electricity technologies. In other words, it is observed that the results of scenario *NF4* are quite similar to those of *NF1*. Geothermal power and biomass are already quite attractive and installed in scenario *NF1* so that the renewable quota of *NF4* becomes redundant. Hence unless there is some particular aid for wind, as assumed in *NF3*, geothermal power and biomass are the only renewable energy sources emerging on stage, and the latter only plays a role if there is a constraint on capacity addi-

tions. Finally, the difference in the impact of a modest but constant price elasticity of electricity demand (-0.02), as assumed in *NF5*, and a gradually increasing one (from -0.01 to -0.05), as assumed in *NF1*, is quite interesting, too, in that the latter seems to offer better chances for the biomass gas turbine technology at the expense of oil- and coal-combustion technology.



(a) Scenario *FLEX* (b) Scenario *NF1* (c) Scenario *NF2* (d) Scenario *NF3* (e) Scenario *NF4* (f) Scenario *NF5*

Fig. 5. Composition of annual capacity additions, by scenario, 2008-2025

The share of renewables among new capacity additions is depicted in Figure 6. As can be seen there is considerable overlap between scenarios *NF1*, *NF2*, and *NF4*, in that the percentage share of renewable power capacity additions decrease from a very high level in the early years (as geothermal is increasingly outstripped by natural gas and later oil) and biomass starts to take a solid 25-30% share after 2015 (which starts to slightly decline thereafter). Scenario *NF5* only differs slightly, in that the peak (at nearly 100%) is reached a bit later and the trough is a bit less pronounced, after which the share stabilizes at a somewhat higher level compared to *NF1*, *NF2*, and *NF4*. The effect of the wind power capacity additions in *NF3* is eye-catching for the years 2022-2025. In other words, in the long run, scenario *NF3* exhibits the highest renewable share of all scenarios at around 39% by year 2025, after peaking in 2022 at slightly above 42%. The inroad of wind power is apparently

strongly driven by the learning effect that occurs as a result of the licensed wind turbine installations in earlier years, as it cannot be explained by the smooth positive drift in fossil fuel prices alone (cf. Fig. 2). This finding points out the profound effect that technological learning might have on the results, and shows that policies aimed at promoting renewable energy technologies – in the long run via learning – can induce a more widespread adoption than originally envisaged.

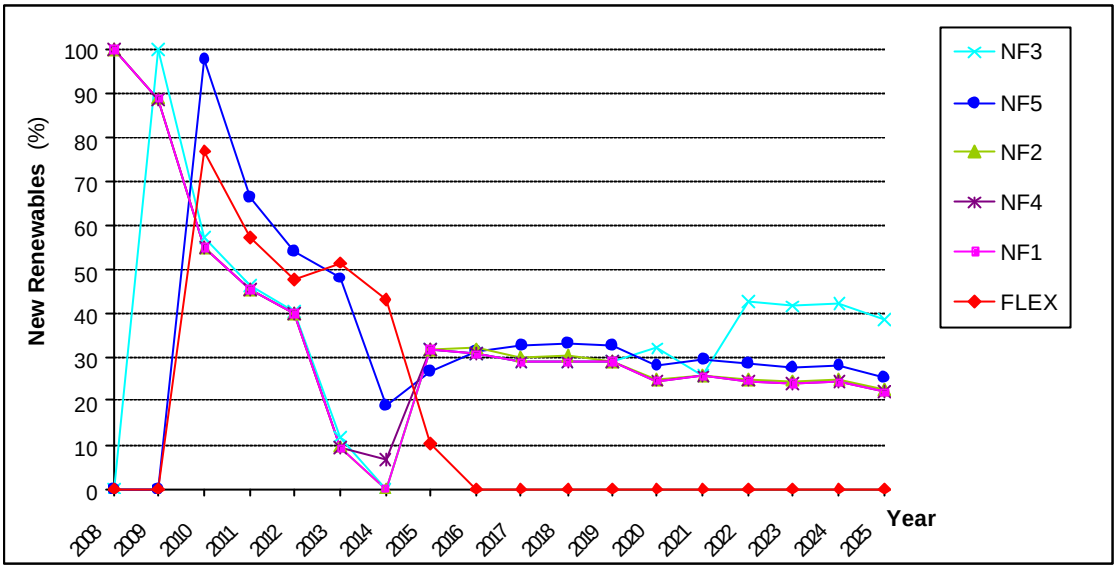
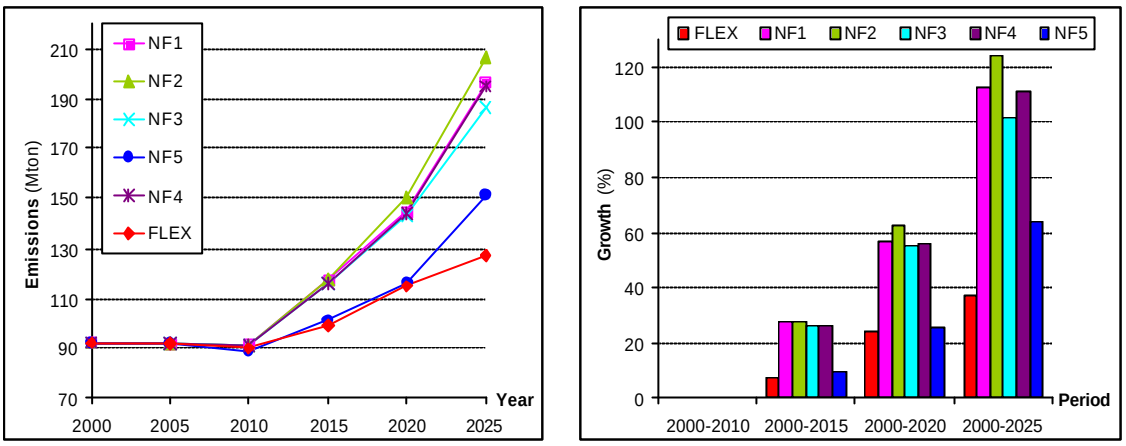


Fig. 6. Percentage share of renewables among new capacity additions, 2008-2025

The scenario-dependent development of CO_2 emissions is depicted in Figure 7. In particular, it can be observed that while scenarios *FLEX* and *NF5* follow each other closely until 2020, in the long run the lowest emissions occur in scenario *FLEX*. This is interesting, as in the *FLEX* scenario there is no investment in new renewable power generation technology after 2015. The comparatively low level of CO_2 emissions in scenario *FLEX* can be explained by the extensive use of natural gas as a relatively clean fuel (which is mostly substituted by coal in the other scenarios). Similarly, scenarios *NF1-4* follow each other rather closely until 2015, after which first *NF2* and then *NF1* and *NF4* exhibit increasingly higher CO_2 emissions compared to *NF3*. It becomes evident from the results for *NF2* that the bounds imposed on natural-gas-fired technology adoption lead to the highest emissions among all the scenarios considered. The lowest emission levels within the non-flex scenarios *NF1-4* are monitored in scenario *NF3*, i.e. the wind turbine licensing scenario with the highest renewable share. The achieved CO_2 reduction in scenario *NF3* (compared to the highest emission scenario *NF2*) amounts to some 21 Megatons (corresponding to a 10% reduction) in 2025. The corresponding figures between scenarios *FLEX* and *NF2* for 2025 are 80 Mt and 39%, respectively. However, since the long-run emissions in scenario *NF3* remain significantly above the emissions in the *FLEX* scenario, it can be said that the diffusion of wind power technology is not sufficient to offset the emission increase due to restricted natural gas use. The growth in CO_2 emissions reaches considerable levels in the long run (e.g. in year 2025, the increase from 2000 levels ranges from 38% in scenario *FLEX* to 124% in scenario *NF2*), as depicted in panel (b) of Figure 7.



(a) Levels (b) Growth

Fig. 7. Development of CO_2 emissions, by scenario, 2000-2025

5 Conclusions

In this paper we have studied how learning curves for renewable energy technologies can be integrated into a dynamic programming model. The model built can guide optimal investment planning in the electricity supply sector and is based on the real options approach to investment. The model has been successfully applied to real data from Turkey. The results show that, due to existing excess power generation capacity, no capacity additions are needed up to the year 2008. Because of their relatively high costs, the diffusion of renewable energy technologies only occurs if targeted policies exist. The promotion of renewable energy technologies expands beyond the initial scope, due to an accelerated learning effect, through which the costs decline to a level at which they can successfully compete with non-renewable alternatives. This finding indicates the essence of technological learning, and points out the importance of policies aimed at increasing the share of renewable power generation. Indeed, the results indicate that particular aid is needed in excess of the new renewable energy law to affect the evolution of the technological structure of new electric capacity investments in the long run. In the absence of subsidies or other promotion policy instruments, market players can hardly be expected to invest in more expensive renewable energy technologies, especially in a liberalized electricity market environment. Financial incentives are needed in the short-term, in order to enable a more widespread adoption of renewable energy technologies in the longer run.

Incentives to finance investments in costly renewable energy technologies can, for example, be created through the operationalization of the flexibility mechanisms introduced by the 1997 Kyoto Protocol. In the case of Turkey, it could be expected that the wind power licenses held by the private sector may turn into real investments through project-based support by the clean development mechanism (CDM) or by joint implementation (JI). Turkey's position with respect to CDM or JI projects is yet unclear[11]. However, the model results and projected CO_2 emission growth rates show that allowances for increasing emis-

[11] Turkey's participation in the UNFCCC has been approved by the Grand National Assembly on October 21, 2003, and since May 2004 Turkey has become the 189th party to the convention. Turkey's request to be withdrawn from Annex II has been accepted at the Marrakech Conference, and Turkey retained in Annex I subject to the condition to enjoy favorable conditions in accordance with the "common but differentiated responsibilities" principle of the UNFCCC. Hence, there exists some uncertainty regarding whether Turkey can host CDM or JI projects, which is due to the fact that the Kyoto Protocol has not yet been ratified.

sions, together with financial assistance for clean energy projects, is essential for a sustainable clean development of the country. Kyoto ratification should therefore bring Turkey into a position that features her to host CDM or JI projects. The possibility of hosting such projects would lead to a variety of different clean energy technology investments, as early project proposals indicate (Kumbaroglu et al., 2004), might induce technological learning and thus far more emission reduction in the long run than initially anticipated.

A certain weakness of the model presented in this paper is that electricity prices do not adjust to changing supply/demand conditions, and that data limitations prevented us from employing market-valuation principles in the RO modeling. Removing these two shortcomings seems to be a fruitful avenue for further research and model development, especially when applying the model to fully liberalized electricity markets where the demand/supply price mechanism plays a more important role.

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