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Technology Adoption Modelling in Situations of Irreversible Investments Under Uncertainty: The Case of the Turkish Electricity Supply Industry

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ABSTRACT

This paper studies energy conversion technology adoption in the electricity sector in the light of irreversible investments under uncertainty, and with a particular interest in an environmentally more sustainable development. We develop a dynamic technology adoption model that, on the one hand, is firmly rooted in economic theory and, on the other hand, takes determinants of investment in available technologies (e.g. life-cycle capital and operation cost) into account. We test the model empirically by applying it to time series cross-sectional data for Turkey. The results indicate significant deviations from actual investment decisions. We find further that the increased adoption of natural-gas-fired power generating technologies in recent years has been ecologically more, but economically less sustainable for Turkey.

Keywords: technology adoption and diffusion, irreversible investment, real option, uncertainty, dynamic programming

JEL Classification Nos.: C61, D81, E22, L94, O33, O52

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1 INTRODUCTION

Increasing concern about the adverse socio-economic and environmental impacts of current energy use patterns, in many cases coupled with staggering levels of fossil fuel import dependence, call for substantial changes in the energy technology and fuel mix towards a more sustainable energy supply system. Technology adoption and diffusion models both at the micro- and macro-economic level can provide valuable insights for a better understanding of the actual and required transitions in the energy-converting capital stock, the related fuel consumption patterns, the underlying investment decisions, and the technological trajectories followed.

In this paper we study energy conversion technology adoption in the electricity sector from the perspectives of irreversible investments under uncertainty and sustainable development. Particularly, by analysing the usefulness of new economic investment theory (real option theory; Dixit and Pindyck 1994) and employing detailed industry-level time series cross-sectional data for Turkey (e.g. for installed capacities, fuel and electricity consumption, input factor and output prices) we develop a dynamic technology adoption model that on the one hand is firmly rooted in economic theory, and on the other hand rests on determinants of investment in available technology options, such as expected capital and operation costs over the lifetime of a certain vintage of a specific technology.

Investment decisions in liberalised markets, in contrast to non-competitive markets, are based on market value maximisation criteria. Because investment projects are contingent upon input and output price variations, the project values evolve dynamically over time. Therefore, it is optimal to invest when the present value of the expected cash flow exceeds the cost of investment by a (strictly) positive amount equal to the compensation for the loss of forfeiting the real option. Two alternative approaches are discussed in the literature to derive the optimal investment rule and the value of the optimal investment. While the *contingent claims analysis* is essentially rooted in the finance literature, the *dynamic programming approach* starts from a given discount rate and considers the maximisation problem of the expected value of discounted cash flows. The two methods are linked through the equivalent risk-neutral valuation principle. In contingent claims analysis one attempts to find some combination or portfolio of traded assets that will be an exact replication of the return and risk pattern from the investment project studied. For the dynamic programming approach developed further in our paper, the timing of the (partially) irreversible investment is formulated as an optimal stopping problem (Murto 2003a, among others). In particular, we use a model that accommodates partial reversibility of investments similar to that used in Moreira et al. (2004) and Chaton and Doucet (2003), respectively. This allows us to analyse the investment decisions taken for different vintages of power (and combined heat-and-power) generating technologies based on different energy resources.

We will discuss and compare our model characteristics and predicted outcome for the Turkish electricity sector (optimal investment rule, value of optimal investment) with the actually observed outcome and also assess the differences in terms of sustainability indicators such as greenhouse gas and pollutant emissions.

Electricity supply in Turkey is characterised by rapid growth on the demand side, and the dominance of hydro power and fossil-fuel-based thermal power generation on the supply side (IEA 2001, Kaygusuz 2002, Ediger and Kentel 1999, among others). Until recently, the Turkish electricity sector was dominated by a state-owned vertically integrated utility. It has been unbundled in 1993 into the Turkish Electricity Generation and Transmission Company (TEAŞ) and the Turkish Electricity Distribution Company (TEDAŞ). TEAŞ is responsible for the operation of all state-owned plants as well as transmission and imports and exports of electricity. Despite of a market opening process that was initiated as early as 1984, when foreign private investors were invited to play a role in the Turkish electricity supply industry[1], the major part of installed electricity generation capacity is still owned by TEAŞ, although the share is gradually declining, and concessionaires, industrial auto-producers and others are gaining market shares. In 2001, TEAŞ has been further separated into EÜAŞ (generation), TETAŞ (trading and contracting) and TEİAŞ (transmission). Currently, in a new wave of reform driven by the desire to introduce competition, to prepare for EU accession, and to meet certain requirements of IMF and World Bank support programmes, further market opening and unbundling is under way.

Power plant expansion planning in Turkey has so far been based on the two main models MAED[2] and WASP[3], whose shortcomings have been discussed in various studies

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[1] A new law in 1984 opened the way for private participation in the electricity sector, facilitating so-called Build-Operate-Transfer and Transfer-of-Operation-Rights contracts (see section 5.1 for further details). Privatisation, however, could not follow by that time as electricity was being interpreted by the constitution as a public service. A constitutional amendment in 1999 made privatisation possible, and the regulatory framework to establish a competitive electricity market has been developed in late 2001.

[2] Model for Analysis of Energy Demand; a simulation model that is being operated by the Turkish Ministry of Energy and Natural Resources since 1984.

(e.g. Ediger and Tatlıdil, 2002; Arıkan and Kumbaroğlu, 2000). Investment planning in a restructured electricity market, which is typically governed by high uncertainty, poses new challenges to the international modelling community (Dyner and Larsen, 2001; among others).

The organisation of the paper is the following: Section 2 contains some general considerations regarding the adoption of electricity generating technologies. Section 3 introduces the literature and theoretical approaches considered, section 4 discusses the theoretical model formulation employed in this paper, and section 5 presents the empirical analysis and results of applying our model to the Turkish electricity generating sector. Section 6 summarizes and concludes.

2 ELECTRICITY SYSTEM CAPACITY (EXPANSION) PLANNING AND THE ADOPTION OF POWER GENERATION TECHNOLOGIES

Generally speaking, because of the long lead times involved, capacity planning in the (largely centralised) electricity supply industry has always been of paramount importance. Before market liberalisation, such capacity planning was mainly undertaken to ensure that installed capacity plus net import capacities are able to meet electricity demand at all times. According to Ku (1995), power plant investment decisions are threefold: (a) *what* to build (choice and mix of technology); (b) *how much* to build (capacity); and (c) *when* to build (timing and sequencing).

(a) What to build is a matter of available technologies (and fuel resources), their performance characteristics, expected construction time and cost, expected operating lifetimes, expected fuel cost, and other factors.

(b) + (c) How much and when to build is a matter of demand projections, existing (over)capacity, the retirement schedule, financial constraints, and other factors.

In real life, capacity planning also involves decisions between proven and new technologies, an evaluation of the costs and benefits of over- and under-capacity, and

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[3] Wien Automatic System Planning; a linear programming model operated by TEAŞ which uses the forecasts of MAED to determine the least-cost electricity generation/capacity expansion plans.

decisions on the postponement of investment decisions in anticipation of regulatory changes (Ku, 1995, p.51). Schedules for investments in the electricity generating capital stock may cover time periods of 40-50 years, and are often strongly influenced by political considerations (e.g. use of domestic energy resources, supply security and diversity aspects, environmental protection).

Electricity supply capacity investments typically involve irreversible decisions with far-reaching (i.e. long-term) consequences. If uncertainties exist that are appropriately taken into account, these may be critical determinants of investor's behaviour, especially in liberalised markets where uncertainty plays a much more important role than in monopolistic markets. Furthermore, capacity additions of some technologies can be made in smaller units (e.g. gas turbines, wind turbines, PV), while for other technologies it may be lumpy and very large (e.g. large hydro power projects), influencing the valuation of risk. Finally, technological uncertainty can also play an important role in decisions related to electricity supply generation capacity, making the valuation of investment options very difficult.

3 LITERATURE REVIEW AND THEORETICAL APPROACHES CONSIDERED

In this section we will provide a short literature review on research closely related to ours and also discuss elements that have been used in applied research on optimal capacity planning in the electricity supply industry under irreversibility and uncertainty.

An early work of optimal capacity choice in the electricity supply sector under uncertainty is that of Brown and Johnson (1969). They assume homogeneous production technologies (i.e. disregarding technological, operational and economic differences) and restrict uncertainty to the electricity demand function.

Levin, Tishler and Zahavi (1985) have studied capacity expansion of electric power generation systems when input fuel prices are uncertain. They consider two different types of technologies (a peak and an off-peak unit) that meet power demand of a given target year and map the probability distribution of the installed capacity and the total cost for any distribution of the fuel prices.

Kobila (1990), in a mathematically very rigorous manner, addresses the choice between hydro and thermal power generation in Norway under uncertainty. He expresses the cost of hydro power as an everlasting and irreversible capital investment, while for thermal power generation he only considers the fuel costs. Electricity demand is treated as stochastic.

Pindyck (1993) studies irreversible investment decisions by incorporating, on the one hand, uncertainties related to physical difficulties in completing a power plant project (technical uncertainty) and, on the other hand, uncertainties related to construction input costs and construction costs affected by government regulation changes. His empirical analysis is geared towards the study of nuclear power plants to be built in the U.S. during the 1980s.

Chaton (1997) determines optimal investment in thermal power plants in a two-period model, given uncertainty in both input fuel prices and electricity demand. Her model explicitly takes the load duration curve into account for demand modelling. Recently, the model has been extended by Chaton and Doucet (2003) to three periods (to account for the option of investors to delay planned investments), to treat the availability of the plants endogenously (as a function of use), and to explicitly account for electricity trading.

Epaulard and Gallon (2000), using real option theory, study the investment choice between nuclear and natural-gas-fired power plants and compare the outcome with traditional net present value (NPV) calculations.

Murto (2003b), in his compilation of papers on dynamic investment models under uncertainty with a main focus on energy markets (doctoral thesis), covers several aspects of optimal capacity expansion modelling, including technological and revenue-related uncertainties, irreversible technology investment choice given different degrees of uncertainty related to alternative investment projects, and the incorporation of game theoretic elements.

Finally, Moreira, Rocha and David (2004) study thermal power generation investments in Brazil by employing a stochastic dynamic programming approach and real option theory. They consider uncertainties in the load, the input fuel price, and other economic factors.

4 MODEL DESCRIPTION

4.1 Load Duration Curve and Merit Order

Traditionally, the demand for power is described by a *load duration curve* (LDC), which is a graphical summary of demand levels with corresponding (non-chronological) time durations. In regulated markets, the LDC is typically used together with *screening curves* (in which annual revenue requirements are plotted as a function of capacity factors (CF), for comparing the generation costs of different technologies) to determine the optimal mix of generation technologies. This procedure, also called the *merit order approach*, is no longer applicable in a restructured market environment because of uncertainty (e.g. regarding cost and demand). Still, the LDC provides a useful summary on a year's worth of hourly fluctuations in electricity demand. A discretised LDC (i.e. one that is segmented into vertical sections) is shown in Figure 1, which also illustrates the significance of some of the variables and parameters defined in the model that is used in this paper. The LDC is segmented into horizontal bands that represent technologies (denoted by the subscript j) allocated to meet certain load sections (bands).

The cost-based ranking of technologies in a merit order that is used for the dispatching of power implies on the LDC that the cheaper ones appear at the bottom of the curve, satisfying off-peak demand with high utilisation rates, whereas peak demand is satisfied by the more flexible but also more expensive technologies for low utilisation rates located on upper levels of the LDC. In the absence of competition, demand is inelastic, implying a fixed LDC and matching base-load dispatching on the screening curve / LDC combination (i.e. determining from the screening curves the CF at which different technologies become cheapest, and using the CF in the LDC to schedule the optimal load dispatching; cf. Chaton and Doucet, 2003, Fig. 1). This traditional technique, however, assumes a stable world that ignores fluctuations in demand, prices and costs. In our model, we will also assume demand for electricity to be price-*in*elastic (as we study the historical capacity expansion decisions in a monopolistic environment), but explicitly consider cost and demand uncertainty in a NPV-maximising model setting.

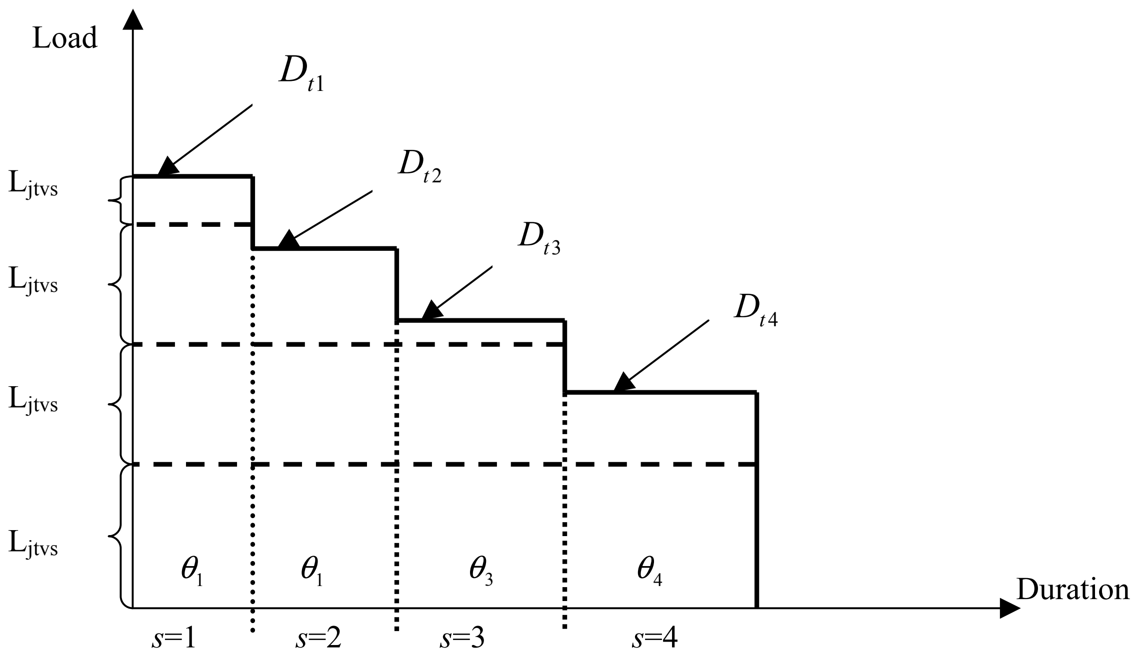


Figure 1. A discretised load duration curve with horizontal bands

4.2 Objective Function

The objective function is formulated in terms of the maximisation of expected net present value [*E(NPV)*], which is computed as the expected discounted difference between revenues and fixed and variable costs that accrue from electricity production. In mathematical terms, it may be expressed as

Maximize

$$E(NPV) = \sum_{j=1}^{J}\sum_{t=1}^{T}\sum_{v=0}^{t}\sum_{s=1}^{P} E_{z_t}(P_t)\cdot L_{jtvs}\cdot\theta_s - \sum_{j=1}^{J}\sum_{v=1}^{T} fc_{jv}\cdot X_{jv} - \sum_{j=1}^{J}\sum_{t=1}^{T}\sum_{v=0}^{t}\sum_{s=1}^{P} E_{z_t}(vc_{jtv})\cdot L_{jtvs}\cdot\theta_s \tag{4.1}$$

where fc_{jv} and vc_{jtv}, respectively, stand for the discounted fixed costs (capital investment)[4] and variable costs (operation and maintenance, O&M) of technology j with vintage v. Hence,

$$fc_{jv} = fc_j(1+r)^{-v} \quad \text{and} \tag{4.2}$$

$$vc_{jtv} = vc_j(1+r)^{-t}(1+r)^{-v} \tag{4.3}$$

where r is the real discount rate. ($E_{z_t}(P_t)$) and ($E_{z_t}(vc_{jtv})$) in equation (4.1) represent the expected values of electricity price and variable costs, respectively, for different states of nature z_t . The installed capacity[5] of technology j, vintage v, is represented by X_{jv}, and L_{jtvs} denotes the dispatched load of technology j, vintage v, operating in the sth section of the load duration curve in year t; the load duration in each section is θ_s.

4.3 Modelling of Uncertainty

The uncertainties arising from input and output price fluctuations are considered by computing their expected values as a first-order autoregressive (AR1) stochastic process with a first-order error term. Hence, we model the variation in fuel prices as

$$vc_{j,t} = \delta + \rho\, vc_{j,t-1} + \varepsilon_t \tag{4.4}$$

where δ and ρ are constants, with $-1< \rho <1$, and ε_t is a normally distributed random variable with mean zero. Similarly, the variation in electricity prices is modelled as

$$P_t = \delta + \rho\, P_{t-1} + \varepsilon_t \tag{4.5}$$

Obviously, NPV-maximizing optimal vintages are determined by the model, which is referred to as *optimal stopping*. The model formulation is completed with the following demand and capacity constraints:

[4] Investments are viewed as sunk costs, i.e. they cannot be (fully) recovered, say, if electricity prices fall and/or the investor wants to disinvest (e.g. dismantling of a dam). Similarly, the investment costs of existing plants are sunk and thus irrelevant for the present model. This *irreversibility* is a typical and reasonable assumption for electricity generation investments.

[5] For simplicity, capacity is assumed to be perfectly divisible.

4.4 Constraints

Constraint No. 1: Available installed capacity must be sufficient to meet the peak load

$$\sum_{j=1}^{J} \sum_{v=0}^{t} a_{jv} X_{jv} \geq E_{z_t}(D_{ts}) \cdot (1+m) \qquad s=1, \; t=1,..., T \tag{4.6}$$

where a_{jv} is the availability factor for plant j and vintage v, and m denotes the reserve margin in percent.

Constraint No. 2: Total plant output must be sufficient to meet the instantaneous power demand levels

$$\sum_{j=1}^{J} \sum_{v=0}^{t} L_{jtvs} \geq E_{z_t}(D_{ts}) \qquad s=1,...., S \quad t=1,..., T \tag{4.7}$$

where the expected demand is modelled as a first-order autoregressive (AR1) stochastic process, i.e.

$$D_{t,s} = \delta + \rho\, D_{t-1,s} + \varepsilon_t \tag{4.8}$$

Constraint No. 3: Output from each plant cannot exceed available capacity:

$$a)\; L_{jtvs} \leq a_{jv} X_{jv} \qquad \forall j, t, s, v = 0,....,t \tag{4.9}$$

$$b)\; \sum_{s=1}^{S} L_{jtvs}\, \theta_s \leq b_j X_{jv} \qquad v = 0,...., t \quad t=1,..., T \tag{4.10}$$

where b_j is the load factor for technology j (the average production of the plant divided by its maximum).

This completes the model formulation, together with non-negativity constraints for all variables except NPV.

5 EMPIRICAL ANALYSIS AND MODEL RESULTS

To empirically illustrate and assess our theoretical modelling assumptions and results, we apply the model formulation presented in section 3 to the Turkish electricity supply sector. To this end we will first analyse the development of electricity supply and use in Turkey.

5.1 Electricity Demand and Supply in Turkey[6]

Electricity demand in Turkey has been growing at a remarkable average rate of 10.8% over the last 50 years, inducing annual investments in the generation, transmission and distribution infrastructure in the order of US$ 4-5 billion. Installed generation capacity today is represented by some 350 power plants and has been estimated to be around 36.3 GW in 2003 (Table 1). Only some 7% of the villages had grid access in 1970, a percentage share that increased to 61% by 1982, and to 99.9% by 1999 (IEA 2001).

Table 1. Electricity balance of Turkey, 1950-2003

	1950	1960	1970	1980	1990	2000	2003*
Installed capacity (MW)	407.8	1’272.4	2’234.9	5'118.7	16’317.6	27’264.1	36’283.1
Electricity generation (GWh)	789.5	2’815.1	8’623.0	23’275.4	57’543.9	124’921.6	139’245.0
Import surplus (GWh)	-	-	-	1'341.2	732.2	3'354.0	3'255.0
Electricity consumption (GWh)	789.5	2’815.1	8’623.0	24’616.6	56’811.7	128’275.6	142’500.0

Data source: TEİAŞ (2002)

* Estimate

Additions to installed capacity have come in bursts, as Table 1 indicates. The evolution of the technological composition (represented by the percentage shares of installed capacity for the different energy sources used) is illustrated in Figure 2.

[6] This subsection is essentially based on IEA (2001) as well as Ediger (2003a) and references therein.

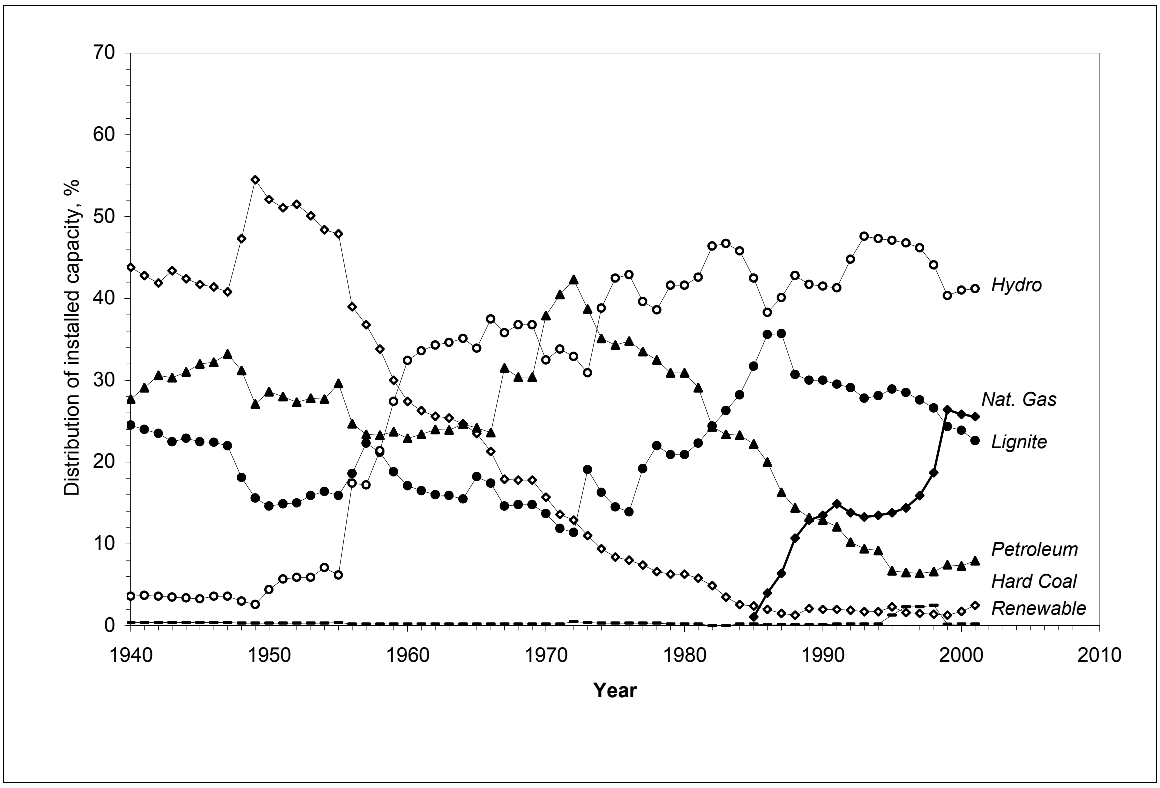


Figure 2. Distribution of installed capacity by energy source (modified after Ediger, 2003 bc)

We will start our analysis of the electricity supply structure from the 1950s onwards. In the 1950s, the dominant fuel for power generation in Turkey was hard coal. Its share in total installed capacity declined gradually from 52.1% (212.6 MW) in 1950 to 27.4% (348.3 MW) in 1960. By that year, hydroelectric energy supply had reached a share in capacity of 32.4% (411.9 MW).

The electricity generation rests on hydro power and fossil-fuelled thermal power generation. The rise of hydro power started with the evaluation of technically and economically feasible hydro power potentials. Turkey’s first hydroelectric power plant was activated in 1956 (567 MW). The largest two hydro power plants in Turkey are Karakaya (1’800 MW) and Atatürk (2’400 MW). Total installed capacity rose from 3.1 GW in 1982 to 11.2 GW in 2000. The remaining economic hydro power potential has been estimated to be abount 20 GW (equivalent to an estimated construction cost of some US$ 30 bn, spread over some 330 additional plants). Investment planning in hydro power plants in recent years has been largely influenced by the huge South-East Anatolia Project (GAP), which combines hydro power use and increased irrigation by utilising the water from the lower reaches of the Euphrat and Tigris rivers. The Karakaya and Atatürk plants are part of the GAP project, which upon completion will comprise an installed capacity of some 7.5 GW, equivalent to about 22% of the total estimated economic hydro power potential of Turkey.

Since the 1970s emphasis has been put on the importance of domestic energy resources, especially on lignite and on hydro power, and much less on other renewables (see Ediger and Kentel, 1999, and more recently Evrendelik and Ertekin, 2003, for useful assessments of the renewable energy potentials in Turkey). The share of (largely domestically produced) lignite in electricity production increased from 19.1% in 1973 to 24.4% in 1982, rose further to 35.7% in 1987 and then declined again to 24.4% in 1999.

The rise of natural gas came in the 1970s, although its share remained very modest until the 1980s. The share of natural-gas-fired power plants rose from 1.1% in 1985 to 26.4% in 1999, and the capacity added was in the order of 5 GW.

First privatisation efforts were undertaken as early as in the 1950s, when construction of power plants were initiated at a larger scale, both by publicly-owned and private enterprises, the latter of which operated under state concession. More extensive privatisation in the electricity sector was initiated in 1984 with the first energy privatisation law 3096 (also known as the "BOT law"), which was issued to enable private actors to build and operate electricity generation, transmission and distribution systems. Law 3096 essentially foresaw two different types of contracts: BOT (Build Operate Transfer) contracts for planned projects and TOOR (Transfer Of Operation Rights) contracts for existing facilities.[7] A further step in private participation followed ten years later, in 1994, with the BOO (Build Operate Own) Law, through which the plant ownership could remain on the investors. Typically, under a BOO, BOT or TOOR contract, the state guarantees to buy a certain amount of the production at specified prices, so that investors can recover their fixed costs. Despite these privatisation efforts, in 2000 some 75% of the installed capacity in the electricity sector were still owned by the government.

[7] BOT: The plant is constructed by private investors who transfer it to the state after an operation period of about 20 years; TOOR: A lease-type agreement is made with private investors who renovate and operate an existing plant.

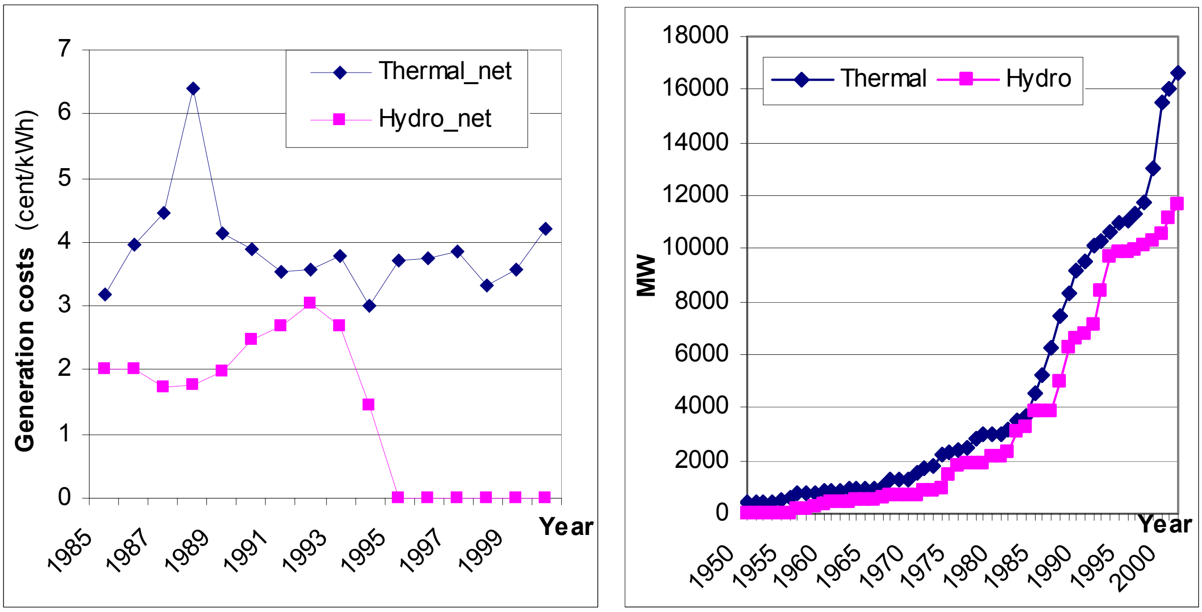


Figure 3. Development of thermal and hydro power generation cost (1985-2000) and installed capacity (1950-2000) over time

The net electricity generation costs are presented in Figure 3 for thermal and hydro power. The costs for hydro power generation exhibit a sudden fall after the Atatürk power plant was taken into operation in 1993. This is because the Atatürk plant has started to produce electricity quite cheaply (at a net cost of 0.03 cent/kWh), replacing older and smaller hydro plants that were generating electricity at considerably higher cost (e.g. Keban at 6.2 cent/kWh, Botan at 10.9 cent/kWh, Bozyazi at 8.9 cent/kWh, Denizli at 31.3 cent/kWh). Note that the generation costs for hydroelectric energy depicted in the left plot of Figure 3 are variable costs only.[8]

Figure 4 illustrates the changing composition of total primary energy supply (TPES) in Turkey over time. The historical dominance of oil imports and the recently significant growth of natural gas imports, up to 16% of TPES in the year 2000, are eye-catching. A remarkable share of renewables is included since 1970. However, it should be noted that over 99% of the renewables are composed of conventional energy sources that include wood and agricultural plant and animal wastes.

[8] The data depicted in Figure 3 are based on TEAŞ (2001). The state-owned hydraulic works (DSI) is responsible for the development of hydroelectrical energy projects - after completion, the electricity generation company EÜAŞ starts to operate the hydro power plants, ignoring the construction costs specified by DSI in their cost accounting reports.

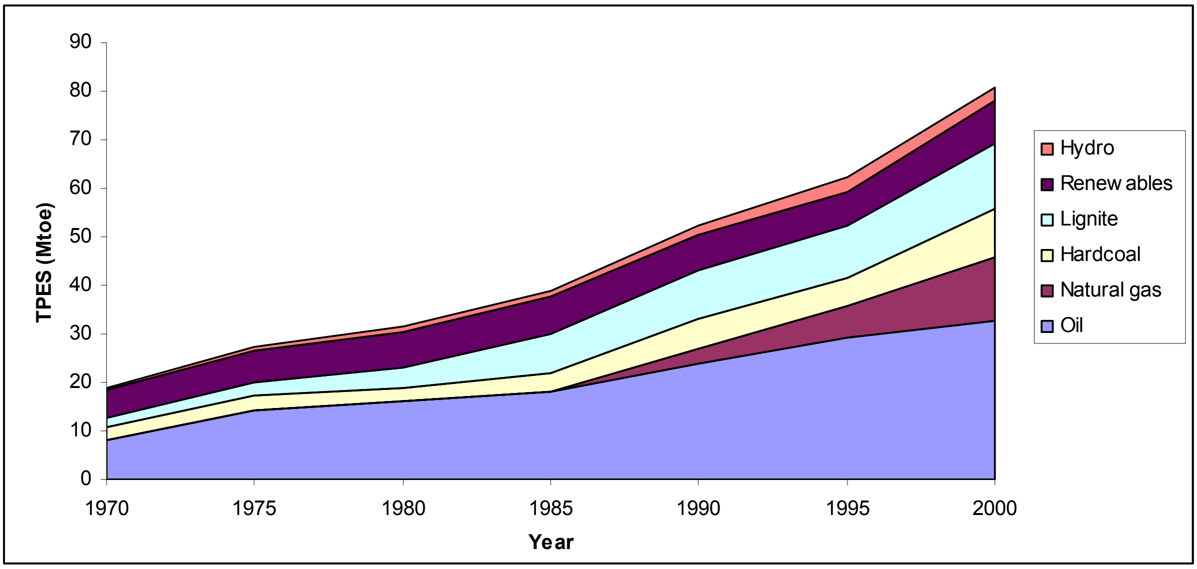


Figure 4. The composition of total primary energy supply (TPES) since 1970

Data source: WEC Turkish National Committee (2001)

Research on greenhouse gas emissions, essentially CO_2, of the Turkish electricity supply industry is still rare. Most of the available energy-environment analyses (e.g. Kumbaroğlu, 1997; Plinke et al., 1990; Taşdemiroğlu, 1992) typically have focused on SO_2 and NO_x emissions, as these pollutant, until recently, had caused the most severe adverse environmental impacts in Turkey. Kaygusuz (2003) and Demirbaş (2003) are two recent studies exploring greenhouse gas emissions in Turkey.

Modelling studies exploring the economic impacts of environmental constraints in Turkey (e.g. Arıkan and Kumbaroğlu, 2002) typically include a highly simplified representation of investment behaviour, without explicitly considering the uncertainty inherent in input and output prices.

The utilisation of renewable energy technologies except hydro electricity is still quite low, amounting to 0.1% of installed capacity in 2000.[9] It should be noted, however, that a considerable renewable energy potential exists in Turkey, amounting to a total of some 495 TWh/year, according to recent studies undertaken by Evrendilek and Ertekin (2003). They have estimated the potential for biomass energy at 196.7 TWh/year, for hydro power at 124 TWh/year, solar energy at 102.4 TWh/year, wind energy at 50 TWh/year, and geothermal

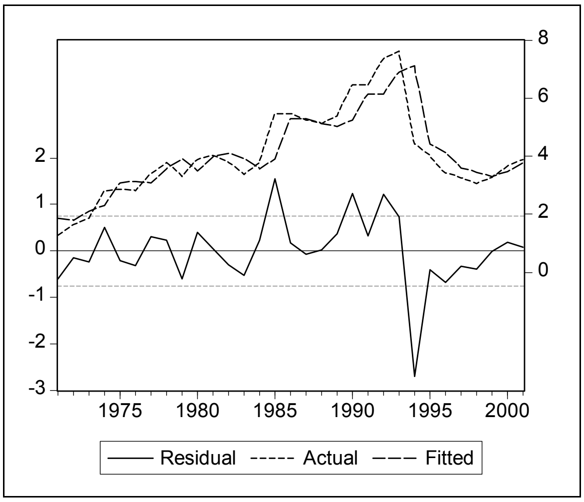
[9] The 0.1% renewable share includes geothermal and wind energy. Hydroelectric energy has a 41% share (11,175 MW) in the total installed capacity for the year 2000.

energy at 22.4 TWh/year. Further discussions on the renewable energy potential and utilisation in Turkey can be found in Ediger and Kentel (1999) and Kaygusuz and Sarı (2003), among others.

5.2 Model Results

In the empirical model application we explore investment decisions for the period 1970-2000, differentiating between various types of thermal power plants (i.e. fired by hard coal, lignite, natural gas, and oil) and hydro and geothermal power technologies, that might be installed at any vintage in the analysis period.

As a first step we have estimated the parameters of the stochastic processes as introduced in section 4 for electricity price, variable cost and peak load (using the econometrics software package Eviews 4.0). Given the small number of observations available and the parsimonious model specification, the fit of all three models is satisfactory and all coefficients are statistically significant. Figure 5 illustrates the uncertainty in electricity prices.



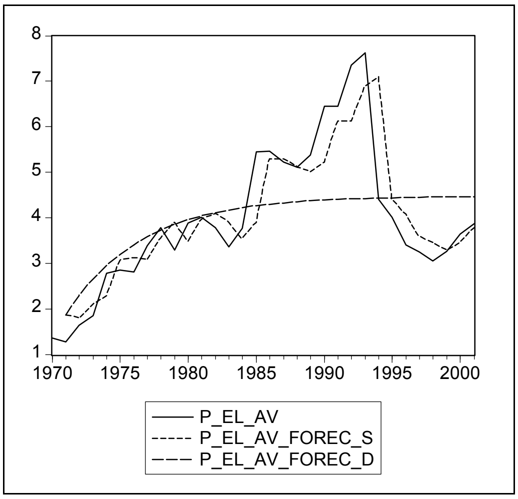


Figure 5. Electricity prices (cent/kWh). Actual, fitted and residuals (left plot) and comparison between actuals and static 1-step ahead and dynamic multi-step-ahead forecast (right plot), within-sample forecasting model for electricity price

The model has been programmed in GAMS and results have been obtained with the solver MINOS. Load factors, annual durations and other reference parameters required for calibration are essentially based on TEAŞ (2001).[10]

The results yield technology selections that differ significantly from the actual choices made by policy-makers and/or investors. This can be observed from Figure 6, which presents the percentage deviation between model-determined and actual total installed capacity levels for thermal and hydro power. As opposed to actual investment expenditures, the NPV-maximizing behaviour of the model prefers to allocate more resources for the construction of hydro power plants than for thermal power plants in the seventies and early eighties, but predicts the take-up of installation of large thermal power plants thereafter. Investments in hydro power rise in the nineties and the model-determined and actual installed capacities become almost equal in 2000, but the share of hydro electricity in total electric energy declines slightly due to the dominating increase in investments into thermal power generating technologies. A closer look into the composition of thermal power, especially the development of natural-gas- and lignite-fired technologies, provides interesting findings. Contrary to the recent development with huge investments into natural-gas-fired technologies, the model prefers to utilise lignite-fired technologies as illustrated in Figure 7. It should be underlined that a possible main reason for this deviation is uncertainty. Natural gas is an imported energy source for Turkey, whereas lignites are domestic. Limited foreign exchange availability and economic instability, from time to time, lead to considerable fluctuations in natural gas prices. Hence the model prefers to invest in a domestic fuel-fired technology whose operation costs are more stable.

[10] Essential base case assumptions are as follows:
- the maximum plant size (electric capacity) that can be constructed per year is 1500 MW for any technology.
- natural gas and geothermal have been restricted such that they cannot be utilized until 1985 and 1984. respectively, when the necessary infrastructure has been available.
- the deviation of aggregate total annual demand from actual values is subject to a tolerance level of +/-20%.
- real interest rate = 8%, reserve margin = 10%, availability factor = 90% (uniform for all technologies).
- CO_2 emission factors are taken as 96.1 kg/GJ for hard-coal-, 108.4 kg/GJ for lignite-, 50.92 kg/GJ for natural gas-fired technologies and 73.74 kg/GJ for oil-fired technologies (factors based on TEK 1994).

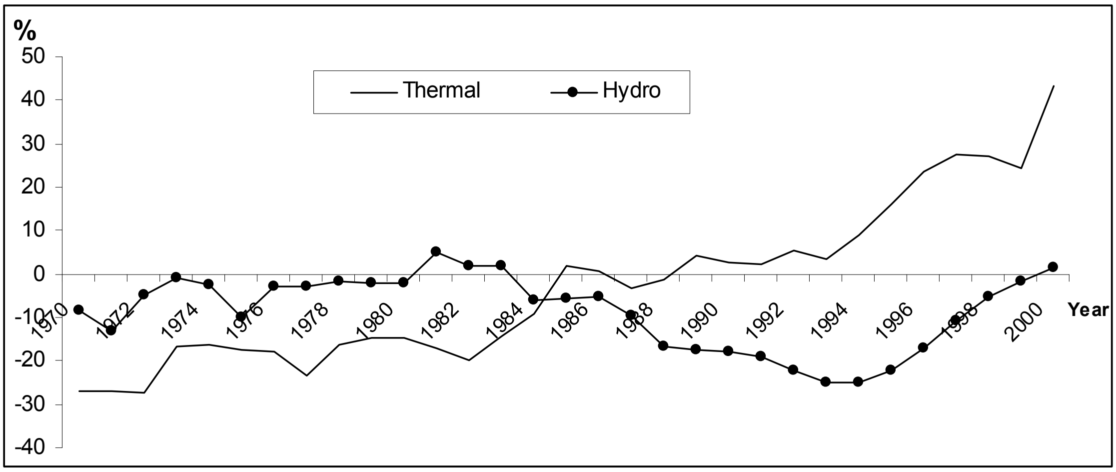


Figure 6. Percentage deviation of NPV-maximizing investments from actual ones

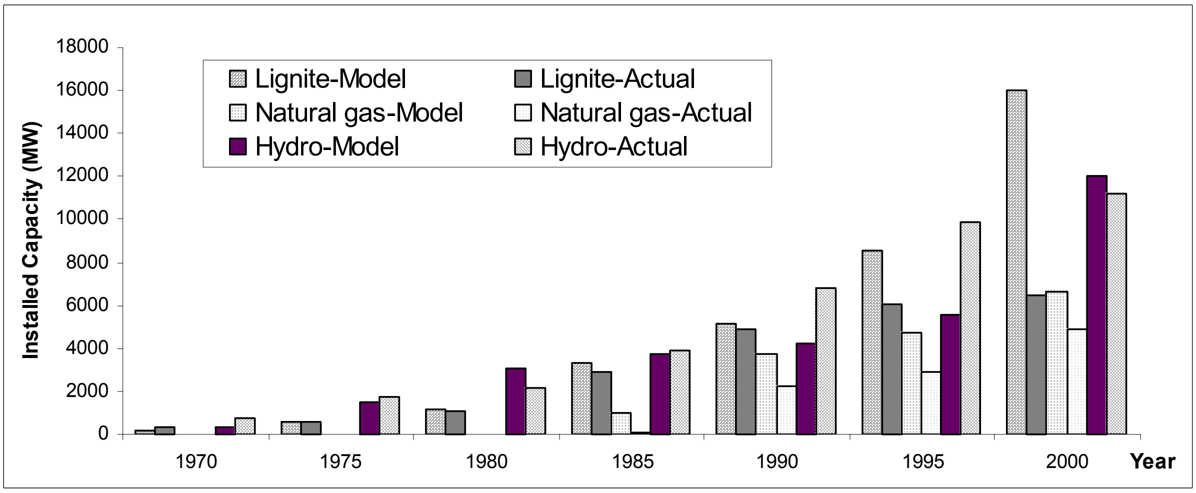


Figure 7. Installed capacities of natural-gas- and lignite-fired technologies

Model-based and actual investments in hydroelectric power plants are quite close in year 2000 (model-based investments accumulate to an installed capacity level that exceeds the actual capacity level by 6%), although there are some deviations in the timing of capacity additions. It should be noted that 97.3% of the total actual hydropower capacity in the year 2000 is based on storage plants (with a dam), 2.3% on run-of-river plants, and 0.4% on natural storage plants (without a dam).

The actual investment behaviour of policy-makers, i.e. to prefer natural-gas-fired power plants, has been more environment-friendly than NPV-maximising investment decisions predicted by the model, as the development of CO_2 SO_2, NO_x and particulate emissions depicted in Figure 8 show. It seems that, although Turkey has not signed the Kyoto

Protocol on Climate Change, she has chosen an ecologically more sustainable path with a slowed-down greenhouse gas emission growth path. It should be noted, however, that pollutant emissions may have been a stronger driver. Especially in the early eighties winter months in major Turkish cities, especially in Istanbul and Ankara, have been characterised by heavy air pollution. This certainly was a main motivation for policy-makers when substituting natural gas as a relatively clean fuel for low-quality domestic coal used in heating systems. Together with the booming investments in gas-fired power generation technologies, Turkey has managed to slow down the growth in pollutant emissions. However, this path has increased the import dependence of the country, which possesses limited foreign exchange availability and relies on heavy foreign exchange inflows to finance her outstanding external debt that has reached some US$ 114 billion (about 78% of GDP) in 2001. Obviously, the utilisation of domestic energy sources would lead to an economically more sustainable development as NPV-maximization under uncertainty suggests.

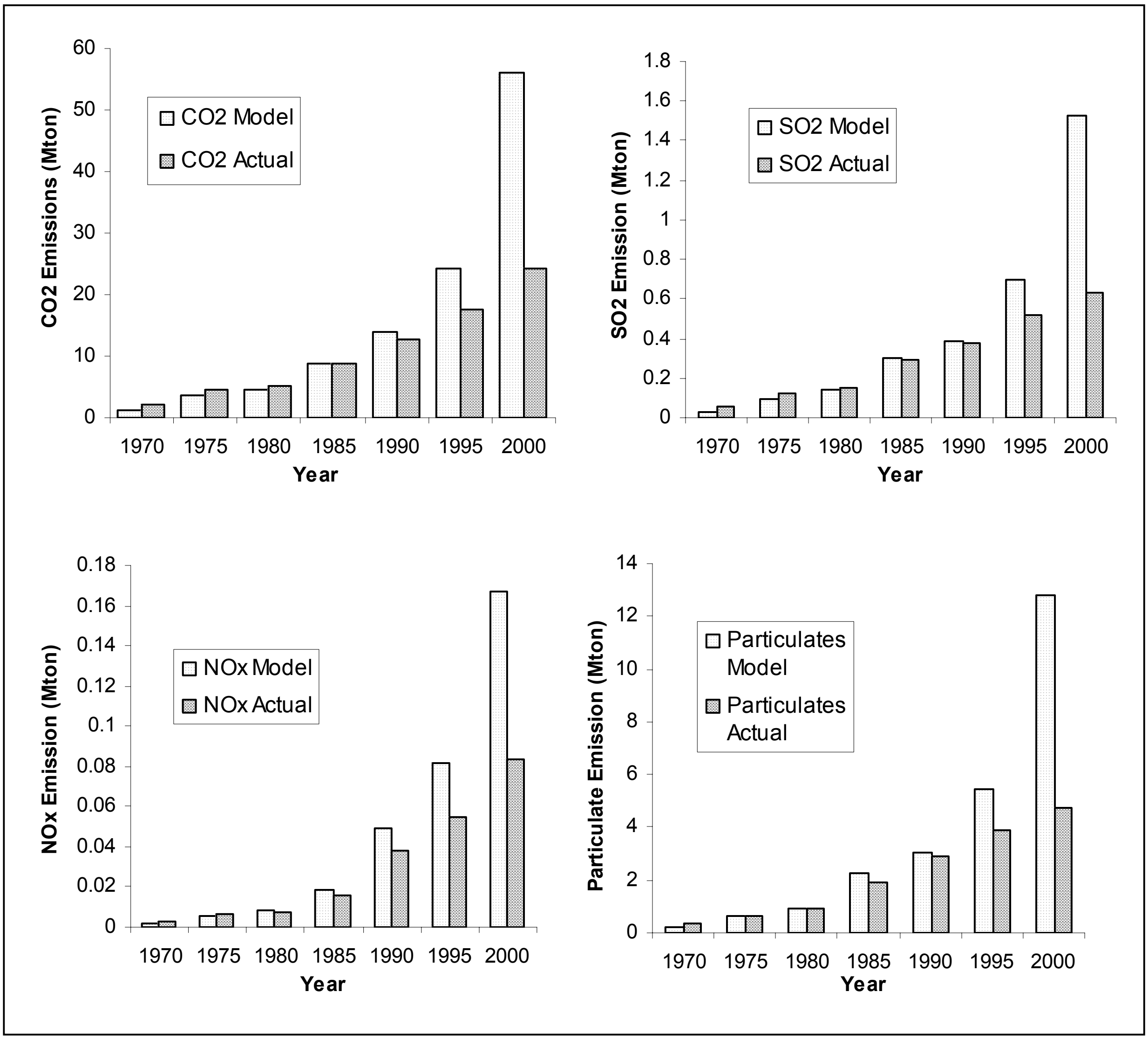


Figure 8. NPV-maximising and actual pollutant emissions

6 SUMMARY AND CONCLUSIONS

In this paper we have discussed the use of a dynamic programming approach for the modelling of irreversible adoptions of electricity generating technologies, taking into account uncertainty and life-cycle capital and operation costs. A particular focus of our investigation has been to study the consequences of electricity conversion technology choices on environmental sustainability.

In an empirical application of the model for Turkey, we find that historical investments strongly diverge from what the model predicts, indicating that the actual investment decisions are far off from what a net present value-based optimisation model would predict. We find further that the increased adoption of natural-gas-fired technologies for electricity generation in reality limits the increase in pollutant emissions, which would otherwise occur from the utilisation of domestic fossil fuel sources (in particular lignites, as is suggested by the model). We explain the dominating investments in lignite-fired power generating technologies with the lower volatility in lignite prices. The instability of natural gas prices, essentially due to economic instability and limited foreign exchange availability in Turkey, reduces the attractiveness of technologies using this fuel. We conclude that reducing the dependence on imported energy sources for electricity generation should be given high priority in policy planning.

The present application neglects the sometimes significant lead times required for the construction of power plants, i.e. an investment asset initiated today starts to generate electricity only some time in the future, sometimes after years. The inclusion of construction lead times, a more sophisticated modelling of uncertainty, and the conduct of sensitivity analyses, are possible avenues for further model improvement and testing.

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