Implications of Diverging Social and Private Discount Rates for Investments in the German Power Industry. A New Case for Nuclear Energy?

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Abstract: For power-plant investments, utilities rely after liberalisation on private financial markets, which are in general distorted. The (related) split of social and private time-preference rates provides another reason for a welfare-enhancing policy intervention, complementary to environmental policy (Heinzel and Winkler 2007). This paper quantifies it and studies its relevance for the German power industry around 2015. The distortions remain moderate as compared to other investment subsidies. However, in contrast to environmental policy alone, its additional implementation makes nuclear power the first option even in the nuclear high-cost scenario. Both policies enhance ecological structural change, which end-of-pipe abatement delays.

Keywords: distorted time preferences, energy industry, environmental and technology policy, conventional energy technologies, CCS technologies

JEL classification: D92, H23, H43, Q48

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1 Introduction

In liberalised energy markets, private utilities rely on private financial markets to finance power-plant investments. However, as is well recognised in economics and finance, financial markets in real world are systematically distorted. The distortion derives in general from different sources. They include, e.g., distortionary taxation, distortionary public investment, imperfect competition, production externalities, adverse-selection problems, or uninsurable long-run risks (e.g. Gollier 2002, Grant and Quiggin 2003, Hubbard 1998, Lind 1982, Mehra and Prescott 2003). The (related) split of social and private time-preference rates induces, in addition to that from the emission externality, a further distortion in the investment conditions for new technologies (Heinzel and Winkler 2007). It provides a new reason to complement environmental policy by another policy, such as technology policy, in the transition to a low-emission energy industry. The purpose of this paper is to quantify and to study the relevance of the welfare implications of diverging social and private discount rates for the German electricity industry around 2015. In Germany, by 2020 40 GWe or about one third of the net installed capacity is to be replaced as a part of usual reinvestment cycles. To this by about 2022 another 20 GWe add due to the political decision to phase out nuclear energy.

The analysis focuses on the threefold investment-related trade-off of a single cost-minimising utility under environmental policy. Disposing over an established polluting power plant with finite lifetime, it has, eventually, not only to decide (i) which new technology to introduce and (ii) when, but also (iii) whether first, or never, to gradually refine its existing plant, e.g., by enactment of an end-of-pipe abatement technology. The analysis proceeds in two steps. First, its choice among three new generation technologies (hard coal, gas, nuclear) is investigated, then its choice of the optimal moment of transition from the established polluting to a new less polluting plant. For the second step the investment conditions are projected on a temporal scale. Seven scenarios are considered. Apart from the no-policy benchmark the cases of environmental policy and varying levels of the social imputed interest rate (r_s) as distinct from the private (r_p) are analysed, first separately, then combined, for the cases of both the absence and the presence of an end-of-pipe abatement option. The focus is on conventional technologies for baseload electricity generation, as they will still play the major role in upcoming reinvestment cycles and are likely to be the most affected by the interest-rate distortion. The unit costs of electricity (UC_{el}) are calculated using the levelised-cost-of-electricity (LCOE) methodology. Technical and economic parameters and sensitivity ranges of the policy parameters are derived from scientific and public studies as cited below.

The paper exceeds previous studies, such as BEI (2004), Enquetekommission (2002), EWI and Prognos (2005), and IEA and NEA (2005), in five particular ways. First, while the importance of the discount rate is well recognised and results are often considered for different levels, the impact of correcting optimal policy interventions as induced by deviations from its socially optimal level has not yet been analysed. Second, the study of their effect against the background of varying CO_2-price levels also provides a detailed analysis of the impact of environmental policy on the ranking of the considered technologies. Third, the projection of the investment conditions on a temporal scale allows to explicitly account for effects on the timing of structural change in the energy industry. Fourth, by taking into account nuclear power, notably in two different cost scenarios, some clarification is added to the relative prospects of this technology in the future German generation mix. Finally, treating emission and abatement costs as separate categories in the financial model, necessary levels of abatement unit costs (AUC) and CO_2 prices are determined for a new end-of-pipe abatement option, such as carbon-capture-and-storage (CCS) technologies, to be relevant.

The paper is structured as follows. Section 2 introduces analytical setting and financial model. Section 3 specifies and discusses the technological and economic parameters. Section 4 analyses the utility's technology choice, section 5 the optimal moments of transition to the new technologies under the seven mentioned scenarios. Section 6 summarises and discusses the results. Section 7 concludes.

2 Analytical setting and financial model

Consider a single cost-minimising utility which runs a coal-fired power plant (T_1) commissioned in 1990, and disposes at its hand over three types of new specific technologies (T_2), a new coal-fired, a gas-fired, and a nuclear power plant available for commercial operation by

2015.[1] In contrast to the fossil technologies, nuclear power is clean in terms of CO_2 emissions.[2] For emission abatement, a CCS technology may be enacted. In accord with the ideal of, in particular, liberalised energy markets perfect competition is assumed for all markets such that the utility acts as a price taker. Electricity is homogeneous. The construction of a new power plant constitutes a small private investment project and does, thus uncorrelated with GDP, not affect the social rate of return, i_s.

The analysis focuses on the influence of two market failures on the utility's optimal decisions, the one stemming from the (negatively valued) CO_2 emissions, the other one associated with the split of social and private rates of time preference. Given a polluting production system, the two externalities become apparent considering a representative private household's (p) and the social (s) welfare functions,

$$W_i = \sum_{t=1}^{T} U[c(t), e(t)](1 + \rho_i)^{-(t-1)} , \qquad (1)$$

with $i = p, s$.[3] Both are assumed to derive instantaneous utility from energy consumption, c, and disutility from net emissions, e, i.e. $\frac{\partial U}{\partial c} > 0$, $\frac{\partial U}{\partial e} < 0$. The emission externality induces environmental policy. As it does not matter whether the optimal CO_2-price level is implemented via an emission tax or an emission permit trading scheme, in the following only directly positive CO_2-price levels ($\tau_e > 0$) are considered. As an outcome of the economic discounting debate, the representative consumer is moreover generally recognised to apply in general a higher rate of time preference than socially optimal, i.e. $\rho_p > \rho_s$ (Heinzel and Winkler 2007). The split time-preference rates do not constitute a market failure in themselves. Their split rather occurs as an effect of some underlying distortion. It provides a general case for a welfare-enhancing policy intervention. In general it results from several different causes such that for the correction of the implied distortions a policy mix is necessary. Thus far, there has been no systematic research with respect to the causes of, as well as their quantitative contribution

[1] Lignite, though the most important domestic energy carrier, is not considered as there is no actual market for it. Due to its persistently low price it is expected to keep its share in the German generation mix in the period under consideration despite a cost-intensive rise in net thermal efficiency from 43 to 48% and its higher emission factor of 0.396 t CO_2/MWh (BEI 2004, EWI and Prognos 2005).

[2] Life cycle assessments show for nuclear power similarly low greenhouse-gas emissions as for renewable energies. For coal they are about 30, for gas about 13 times higher (Owen 2004, Fritsche et al. 2007).

[3] See Heinzel and Winkler (2007) for an encompassing welfare analysis in a general equilibrium model.

to the split. Therefore, in this paper the *bundle* of policy measures necessary to correct the split and resulting distortions is summarised by the term technology policy. For the investing utility the diverging time-preference rates materialise in a distorted financial market. Thus, the (private) imputed interest rate, based on its market observations, exceeds the socially optimal, i.e. $r_p > r_s$.

The unit costs of electricity are determined based on the LCOE methodology. The particular financial model, adapted from Bejan et al. (1996: ch. 7), is introduced in appendix A.1. This methodology has been criticised for not sufficiently accounting for the increased uncertainty of power-plant investments after liberalisation (e.g. IEA and NEA 2005, MIT 2003). Instead, especially real-option approaches have been used (Epaulard and Gallon 2001, Gollier et al. 2005, Roques et al. 2006, Rothwell 2006). However, for the sake of comparability with previous studies and as there is thus far no alternative analytical scheme established, this paper stays with the conventional approach.

3 Data and parameter specification

The data at the basis of the analysis in sections 4 and 5 refer as far as possible to the situation in Germany around 2015. The parameters are summarised in appendix A.3.

3.1 Technical parameters

The technical and economic estimates for the reference power plants refer in the case of coal to plants operating on the basis of combustion of pulverised coal in conventional boilers, in the case of gas to a combined cycle gas turbine (CCGT). For nuclear power they refer to the European Pressurised Water Reactor (EPR), a large boiling- (i.e. light-) water reactor of generation III+ of nuclear power stations, designed to meet German and French safety standards. It is currently the most seriously discussed build for new deployment in Europe. Oriented towards the prospected size of the EPR, a net installed capacity to be replaced of 1,500 MWe is considered. The plants are supposed to operate with a capacity factor 85%. Generally accurate for coal, this figure is relatively high for gas and rather low for nuclear. As regards the technical parameters of the coal-fired reference power plants, net thermal efficiencies of 45 and

51%, respectively, a construction period of 4 and an economic lifetime of 40 years are assumed, for the gas-fired power plant 60%, 2 and 25 years, for the nuclear power plant 38%, 5 and 40 years, respectively.

3.2 Cost parameters

Fossil technologies. Oriented towards BEI (2004) and IEA and NEA (2005: 120), for the old and the new coal-fired power plant, respectively, specific investment costs of 925 and 1,025, specific decommissioning costs of 34.5, fixed specific annual O&M costs of 40 and 36.6 T-€/MWe and variable specific O&M costs of 4.0 and 2.7 €/MWh are assumed. The respective figures for gas are 525, 15.8, 18.8 T-€/MWe and 1.6 €/MWh. Fuel prices are expected to develop differently among the energy carriers. For hard coal, in the considered period, i.e. 2015–55, reinforced by increasing oil prices for transport, moderately rising real prices are expected (EWI and Prognos 2005, 2006, IEA and NEA 2005). Real gas prices are supposed to increase more significantly due to worsening reservoirs and high transport costs, despite decreasing real costs for transport via pipeline or liquefied natural gas. For clarity of results, though clearly restrictive, the analysis focuses on one medium expected fuel-price level for each energy carrier considered. The consideration of different price scenarios would have neatly complicated the results without changing them in substance. The coal and gas price assumptions refer to the indications given in EWI and Prognos (2005: 296) for Germany and the escalation expressed in the older estimations cited in IEA and NEA (2005: 121). The projected prices are the prices at the power plant, i.e. including transport and processing (Table 1). They do not include the natural gas tax. For the old coal-fired reference power station, in this paper a constant mean coal price of 6.70 €/MWh is assumed, for the new one 7.05 €/MWh, for the CCGT reference power plant a constant mean gas price of 16.8 €/MWh. For later commissioning dates, the mean gas price is derived, equivalently, as the 40-years arithmetical mean based on the above indications.

Nuclear power. The expected costs and prospects of nuclear power after liberalisation are the object of an ongoing debate (e.g. Enquetekommission 2002, Epaulard and Gallon 2001, Gollier et al. 2005, IEA and NEA 2005, MIT 2003, NEA 2003, Roques et al. 2006, Rothwell

Year	Coal €/MWh	Gas €/MWh
2015	6.552	13.968
2020	6.552	14.580
2025	6.624	15.192
2030	6.696	16.020
2040	7.334	18.230
2050	7.972	20.163

Table 1: Real prices for hard coal and natural gas at the plant (€/MWh) (EWI and Prognos 2005: 296, IEA and NEA 2005: 121, own calculations).

2006, The University of Chicago 2004). As important factors the lack of recent construction experience, regulatory and political obstacles related to obtaining construction and operating licenses for new plants, and the long payback period associated with high capital costs and large plant size are mentioned. In addition to the direct costs, different aspects are often suggested to entail external costs. They include radioactivity releases in routine operation, radioactive waste disposal, future financial liabilities from decommissioning and dismantling, and severe accidents. Under current regulation, capital and operating costs and fuel-cycle facilities internalise most of the potential external costs. In particular, high level waste disposal costs, until final repositories are in operation, are treated as future financial liabilities and included in the fuel costs. With regard to effects of severe accidents the third-party liability system has been implemented as a special legal regime to provide insurance coverage for any potential damages. For the case of Germany, it is to be noted that the question of nuclear waste treatment and final disposal is, however, not yet fully decided on political level. Uncertainties are, moreover, still associated with the valuation of severe accidents. They are discussed in economics as a part of the more general debate on the valuation of low-probability high-consequence negative events (e.g. Eeckhoudt et al. 2000, Itaoko et al. 2006, Kunreuther et al. 2001, Schneider and Zweifel 2004). While these studies have considerably been refining the respective tools and considerations, still more research needs to be done, notably for Germany, in order to provide for a well-pondered basis for political decisions.

In view of the wide range of figures in the literature, two nuclear cost scenarios are considered. The *low-cost* scenario (N_l) assumes specific investment costs of 1,800 T-€/MWe, as a moderate lower bound oriented towards Enquetekommission (2002) and IEA and NEA (2005), the *high-cost* scenario (N_h) 2,600 T-€/MWe, as a moderate upper bound according to the more pessimistic Enquetekommission (2002) figures.[4] For both cases, the specific decommissioning costs are assumed to amount to 155 T-€/MWe, the fixed specific annual O&M costs to 30 T-€/MWe and the variable specific O&M costs to 3.6 €/MWh (IEA and NEA 2005: 120). Nuclear fuel costs, comprising front- and back-end costs, are expected to continue to stay constant in the next decades (The University of Chicago 2004). Following the indications in IEA and NEA (2005: 44) for Germany, the total nuclear fuel cycle unit costs are assumed to amount to 4.0 €/MWh.

Abatement costs. The pollution intensity of a technology depends on the emission factor of its fuel input and a plant's gross thermal efficiency. The emission factor is defined as the mean mass of pollutant per energy unit (calorific value) of the fuel input. For the subsequent analysis, CO_2 emission factors for coal and gas of 0.338 and 0.2 t CO_2/MWh input, respectively, are assumed (BEI 2004: A–9). In the given analytical setting the utility disposes over two abatement options. First, it can introduce a new less polluting technology. Second, it can enact an end-of-pipe abatement technology refining its existing and, if polluting, its new electric generation technology. Only in the second case particular abatement costs arise. The debate on end-of-pipe abatement has recently been revived by the development of CCS technologies as a major approach for the (quasi) complete abatement of carbon emissions of (large) power stations (EWI and Prognos 2005: 121–125, WI et al. 2007). In conventional processes, CO_2 is captured from the flue gases produced during combustion. Best known is chemical absorption via aqueous alkaline solvents such as monoethanolamine (MEA). It is expected to be among the first such technologies available by 2015. Thus far, only relatively broad cost estimates for CO_2 capture, transport and storage have been indicated. Following EWI and Prognos (2005: 125), specific CCS full cost ranges of 37–70 and 32–65 €/t CO_2 for coal and gas, respectively, are assumed. In the analysis below, AUC of 10–60 €/t are considered.

[4] Neither BEI (2004) nor EWI and Prognos (2005) particularly treat nuclear power.

3.3 Policy parameters

Environmental policy. For the utility, environmental policy becomes relevant in form of a positive emission price, τ_e. $\tau_e(t)$ indicates the constant mean real price per ton CO_2 for the period t under consideration. It directly imposes the emission costs to the polluting utility. The sensitivity range for τ_e in the analysis below is oriented towards the CO_2 prices which have been occurring under the EU emission trading scheme to which the EU Member States, including Germany, are subject since 2005. In its first phase 2005–2007 CO_2 prices have been ranging between 6 and 30 €/t, with a core range of about 15–25 €/t (e.g. Borak et al. 2006, ECX 2007, Sijm et al. 2005, 2006, Uhrig-Homburg and Wagner 2007).[5] In the second period the supply of EU allowances (EUA) will be reduced as compared to the first and later on generally continue to decrease, such that for an at best similarly decreasing demand, non-decreasing prices might be expected. However, notably in view of ongoing discussions concerning, e.g., the initial allowance allocation, the banking option, and polluter participation more generally, concrete projections for 2015 and later remain difficult. The penalty levels for illegal emissions, fined with 40 €/t in the first trading period and 100 €/t from the second period onwards, set a neat upper bound for the expected price development. For the environmental-policy parameter, τ_e, in this study a sensitivity range of 0–60 €/t is considered. The range of 5–30 €/t is taken as its relevant range in the period under consideration, i.e. the range in which CO_2 prices are expected to stay most likely.

Technology policy. A power-plant construction project should yield at least the return of an alternative investment on financial markets. This is generally equivalent to having a positive net present value. Decisive for its calculation is the real imputed interest rate. It derives as the mean of the (real) rates of return on equity and debt weighted with the fractions of equity and debt financing, respectively. To account for the distorted financial markets, the analysis below considers a private (benchmark) level of the real imputed interest rate (r_p) as deriving from the utility's market observations as against a range of socially optimal ones (r_s). For convenience and corresponding to the common practice in the literature, no distinction is made regarding

[5] At present, studies on the issue have not left the working-paper status. In this paper no distinction is made between spot and forward prices. Preliminary results indicate that the latter exceed the first and that forward markets lead the price discovery process.

the specific financing conditions of particular technologies. The welfare implications of the time-preference distortion are quantified at the deviation of the UC_{el} at the busbar from their socially optimal level.

In the cited studies the discounting issue has been treated in varying degrees of intensity. IEA and NEA (2005: 183) considers a 5% discount rate as approximately consistent with investments in the former regulated environment, and 10% as a proxy for power-plant investments in deregulated markets in the U.S. MIT (2003) and The University of Chicago (2004) calculate for upcoming US nuclear power investments with $r_p = 0.125$. For Germany, IEA and NEA (2005: 122f) adopts the general 5 and 10% rates, while BEI (2004: 8-2) uses an 8% imputed interest rate. Schneider (1998: 51) considers scenarios with real rates of 'low' 5.7, 'probable' 8.9, and 'high' 12.2%. EWI and Prognos (2005: 295) uses a 10% rate, referring to Enzensberger (2003) who found $r_p \in [0.08, 0.12]$ for respective investments in Germany.[6] Social discount rates, on the other hand, have thus far been determined in different ways. Germany has been applying a 3% rate for the evaluation of public projects based on the federal government's average real refinancing rate over the past five years, France an 8% real rate derived with respect to the marginal product of capital. In the UK, until 2003 a 6% rate was applied based on considerations of both capital costs and social time preferences. After re-basing it then entirely on social time preferences, it dropped to 3.5%. Evans and Sezer (2004, 2005) apply the latter approach to major EU and OECD countries, finding, e.g., for France a real rate of 3.2, for Germany 4.3, for Japan 5.0, for the UK 4.0, and for the U.S. 4.6%. Denmark and Ireland display the extrema with 2.4 and 6.8%, respectively. The variation between the rates is mainly due to differences in the national per capita growth rates in the considered years, 1970–2001. Given the current state of research, the above rates for power-plant financing and the social discount rates are derived with respect to both different models and data. Inhowfar the latter rates are actually consistent with those occurring on undistorted financial markets is an important matter for further investigation. Probably, the present figures rather describe a lower bound for the socially optimal discounting of private investments. This paper assumes $r_p = 0.1$. For the social level a sensitivity range of $r_s \in [0.02, 0.08]$ is considered.

[6] Enquetekommission (2002) does not contain a treatment of the discounting issue.

4 Technology choice under environmental and technology policies

This section studies based on the above assumptions the single and combined influences of environmental and technology policies on the utility's choice of a new electric generation technology, first in the absence, then the presence of a CO_2 abatement technology.

4.1 Technology choice without abatement technology

In the no-policy benchmark, the new hard-coal power plant displays the lowest unit costs of electricity (UC_{T_2}), before gas, nuclear in the N_l and N_h scenarios (Table 2).

	UC_{T_2}			
r_p	C	G	N_l	N_h
0.1	37.12	40.33	46.05	58.16

Table 2: Unit costs of electricity at busbar of new plant alternatives in no-policy benchmark (€/MWh) (own calculations).

To understand the following results it is useful to know the UC_{T_2} contributions of the single cost components distinguished in appendix A.1 (Table 3). Striking are the high CC and low FC shares in the cases of nuclear, and the high FC and low CC shares in the case of gas. The DC share amounts in any case to less than 1%.

	Shares in UC_{T_2}			
	C	G	N_l	N_h
CC	41.6	18.8	59.2	67.7
OMC	20.5	10.2	16.5	13.1
FC	37.7	70.9	23.5	18.6
DC	0.2	0.1	0.8	0.6

Table 3: Shares of capital investment, O&M, fuel, and decommissioning costs in unit costs of electricity of new plant alternatives in no-policy benchmark, discounted to year of commissioning (percent) (own calculations).

4.1.1 Sensitivity under environmental policy

The UC_{T_2} behavior of the reference power plants if an emission price τ_e as described in section 3.3 is implemented is displayed in Figure 1. Hard coal remains the first alternative as long as $\tau_e \leq 9.75$ €/t. For $\tau_e \in (9.75, 17.0(53.5)]$ €/t gas dominates in the N_l (N_h) scenario. For

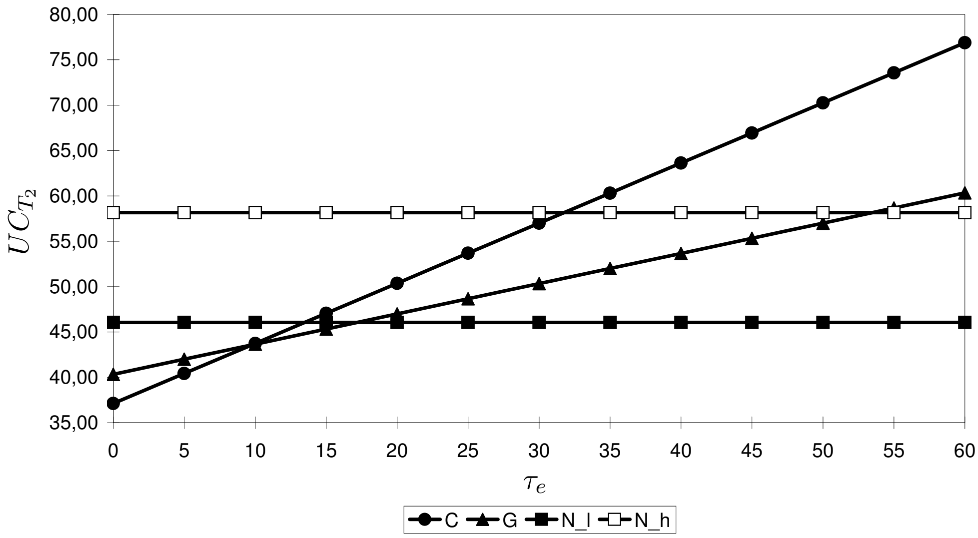

Figure 1: Unit costs of electricity of new plant alternatives for varying CO_2-price levels (€/t) under $r_p = 0.1$ (€/MWh) (own calculations).

$\tau_e > 17.0$ (53.5) €/t nuclear is the first option. The varied UC_{T_2} impact of environmental policy reflects the different emission factors and efficiencies among the technologies. Accordingly, gas becomes, despite its high FC share, dominant over coal for lower τ_e within the relevant range. For nuclear power there is a certain τ_e at which its ecological advantage also turns into an economic.

4.1.2 Sensitivity under technology policy

Figure 2 shows the UC_{T_2} behavior of the new plant alternatives if the socially optimal level of the imputed interest rates is implemented as described in section 3.3. Apart from the reversal between gas and nuclear in the N_l scenario as second cheapest technology for $r_s < 0.054$, the technology ranking remains unaltered over the considered r_s range as compared to the no-policy benchmark. The varied UC_{T_2} impact of the r_s implementation among the technologies depends on their different CC shares, clearly dominating a slight counteracting DC impact. It is, accordingly, the strongest in the case of nuclear in the N_h scenario, before nuclear in the N_l scenario, coal and gas. The UC_{T_2} distortion can be calculated as the difference between

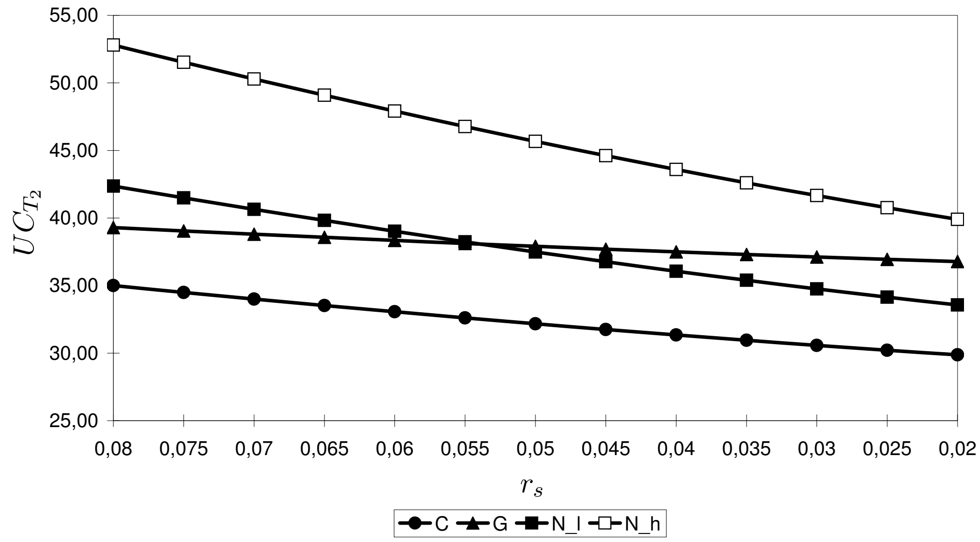

Figure 2: Unit costs of electricity of new plant alternatives for varying levels of social imputed interest rate (€/MWh) (own calculations).

their levels evaluated at r_p and r_s. For $r_s \in [0.02, 0.08]$, for coal, gas, and nuclear in the N_l (N_h) scenario the respective distortions range between 2.12–7.24, 1.04–3.55, and 3.68–12.48 (5.36–18.25) €/MWh, or 5.7–19.5, 2.6–8.8, and 8.0–27.1 (9.2–31.4)% of the distorted UC_{T_2}, respectively.

4.1.3 Sensitivity under environmental and technology policies combined

The combined influence of environmental and technology policies in the N_l and the N_h scenario, respectively, over the τ_e range considered for $r_p = 0.1$ and exemplary r_s of 0.08 and 0.02 can be seen from the strong UC_{T_2} lines and their parallels in Figures 3 and 4 below. In the N_l scenario, for $r_s \in [0.02, 0.08]$ coal remains the first option until $\tau_e \in [5.5, 11.0]$ €/t. Above $\tau_e \in [5.5, 11.0]$ €/t, nuclear directly follows coal as most economic option. In the N_h scenario, for $r_s \in [0.04, 0.08]$ coal remains the least-cost option until $\tau_e \in [13.0, 18.5]$ €/t, for $r_s \in [0.02, 0.04)$ until $\tau_e \in [15.0, 18.5)$ €/t. For $r_s \in [0.04, 0.08]$ gas is the first option for τ_e in intervals of (13.0,40.5]–18.5 €/t, but vanishes as such for $r_s < 0.04$ irrespective of τ_e. For $r_s \in [0.04, 0.08]$ nuclear follows gas as the most economic option above $\tau_e \in [18.5, 40.5]$

€/t, for $r_s \in [0.02, 0.04)$ directly coal above $\tau_e \in [15.0, 18.5)$ €/t. The impact of the additional technology-policy enactment to environmental policy reflects its effect in the case of technology policy alone. Coal tends to be favored, though less than nuclear. Gas persists as least-cost option only in the N$_h$ scenario, for more moderate levels of technology policy. Also there it is, however, succeeded by nuclear for $r_s \in [0.04, 0.0625)$ already within the relevant τ_e range.

4.2 Technology choice with abatement technology

End-of-pipe abatement with fixed AUC may constitute a relevant option only under environmental policy. It fixes the UC_{T_2} for any $\tau_e \geq AUC$ at their level for the given AUC. Under environmental policy alone, in both scenarios thus coal remains the least-cost option until $\tau_e \leq 9.75$ €/t irrespective of the AUC level. For $\tau_e \in (9.75, 17.0(53.5)]$ €/t gas is the first option in the N$_l$ (N$_h$) scenario irrespective of the AUC level, and for $AUC \in [10.0, 17.0(53.5)]$ €/t and $\tau_e > 9.75$ €/t, nuclear power for $\tau_e, AUC > 17.0$ (53.5) €/t.

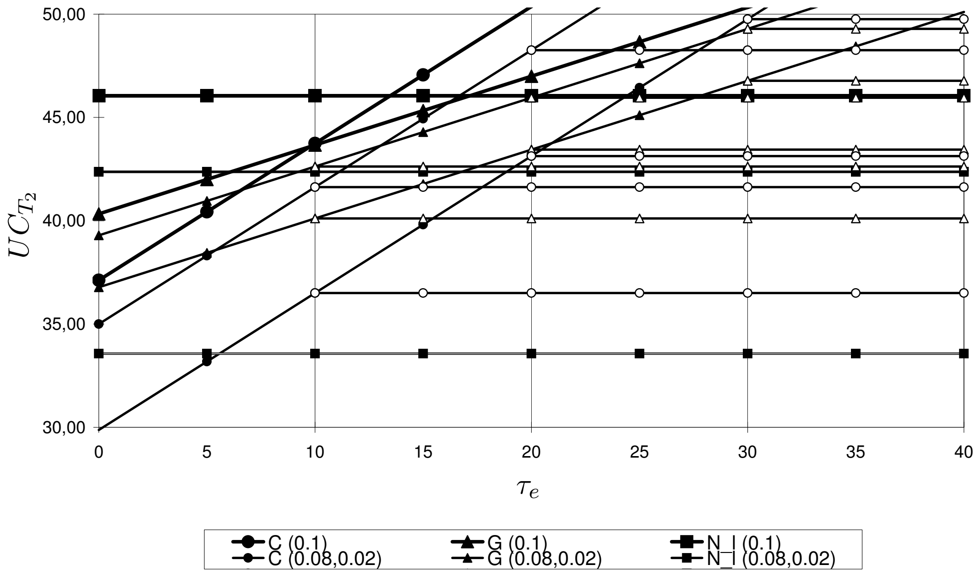

Figure 3: Unit costs of electricity for varying CO$_2$-price levels and abatement unit cost levels between 10 and 60 €/t in steps of 10 € under $r_p = 0.1$ and social imputed interest rates of 0.08, 0.02 in N$_l$ scenario (€/MWh) (own calculations).

Figures 3 and 4 display for the N$_l$ and the N$_h$ scenario, respectively, the UC_{T_2} under environmental and technology policies combined. In the N_l scenario, for $r_s \in [0.07, 0.08]$ coal remains the least-cost option until $AUC \in [10.0, 11.0]$ €/t irrespective of τ_e, as until $\tau_e \in [10.0, 11.0]$ €/t irrespective of the AUC. For $r_s \in [0.02, 0.07)$ it is the least-cost option until $\tau_e \in [5.5, 10.0)$ €/t, irrespective of the abatement option. Nuclear dominates for $r_s \in [0.07, 0.08]$ above $\tau_e, AUC \in [10.0, 11.0]$ €/t, for $r_s \in [0.02, 0.07)$ above $\tau_e \in [5.5, 10.0)$ €/t. In the N_h scenario,

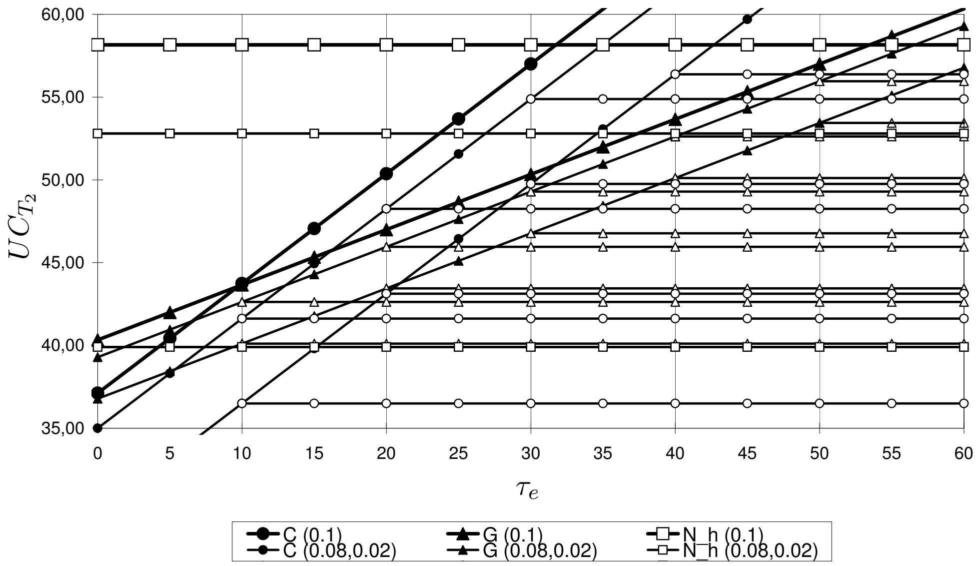

Figure 4: Unit costs of electricity for varying CO_2-price levels and abatement unit cost levels between 10 and 60 €/t in steps of 10 € under $r_p = 0.1$ and social imputed interest rates of 0.08, 0.02 in N_h scenario (€/MWh) (own calculations).

for $r_s \in [0.04, 0.08]$ coal remains the least-cost option until $AUC \in [13.0, 18.5)$ €/t irrespective of τ_e, as until $\tau_e \in [13.0, 18.5)$ €/t irrespective of the AUC. For $r_s \in [0.02, 0.04)$ it is the first option until $AUC \in [15.0, 18.5)$ €/t irrespective of τ_e, as until $\tau_e \in [15.0, 18.5)$ €/t irrespective of the AUC. For $r_s \in [0.04, 0.08]$ gas is the first option for AUC in intervals of [13.0,40.5]–18.5 €/t and above $\tau_e \in [13.0, 18.5]$ €/t, as for τ_e in intervals of [13.0,40.5]–18.5 €/t and above $AUC \in [13.0, 18.5]$ €/t. For $r_s \in [0.02, 0.04)$ it vanishes as first option irrespective of the τ_e and AUC levels. For $r_s \in [0.04, 0.08]$ nuclear dominates above $\tau_e, AUC \in [18.5, 40.5]$ €/t following gas, for $r_s \in [0.02, 0.04)$ above $\tau_e, AUC \in [15.0, 18.5)$ €/t following coal. The additional technology-policy enactment to environmental policy thus expands the scope of relevance of the abatement option, though only for very low AUC, also to coal. It restricts it moreover for gas to only higher r_s in the N_h scenario for less high AUC. As compared to the case without abatement technology the availability of the abatement option fixes, as coal for very low AUC in both scenarios, gas in the N_h scenario as first option even until relatively high AUC for all τ_e above relatively low. The scope of nuclear as least-cost option is, accordingly, restricted by these cases in the two scenarios.

5 Replacement times under environmental and technology policies

In an environment of comparatively rapid technological change, the policy impact on the timing of structural change constitutes an important aspect. Beginning in 2015 the utility has at any moment the choice between continuing to use its established technology and switching to one of the new less polluting. The period of analysis extends from $t_1 = 0$ (2015), where $UC_{T_2} > UC_{T_1}$ for all new technologies, until t_n, the moment of transition to the highest-cost alternative, both in the no-policy benchmark.

Definition 1 (Optimal moment of transition)
Given strictly monotonously rising $UC_{T_1}(t)$ and monotonous and less steep $UC_{T_2}(t)$ than $UC_{T_1}(t)$ in $[t_1, t_n]$, the optimal moment of transition from production with technology T_1 to technology T_2, t_{opt}, is the moment $t \in [t_1, t_n]$ from which $UC_{T_1}(t) \geq UC_{T_2}(t)$.

The conditions of Definition 1 are sufficient for t_{opt} to exist and be unique. The UC_{T_1} are calculated following the indications in appendix A.2 and section 3.2. For their derivation an $OMC_{fix}(14) = 80.0$ T-€/MWe is considered. For the new plants, for convenience, the technologies, and thus CC, DC, OMC, are assumed to stay constant over time, while fuel prices follow their real expected development (Figure 5). In the following, again first the case without, then with CO_2 abatement technology is studied.

5.1 Replacement times without abatement technology

In the no-policy benchmark, the new coal-fired power plant succeeds its predecessor after 40 years of operation (Table 4). The other technologies would replace the existing plant, in case of their sole availability, only after the end of its expected economic life. For the given data

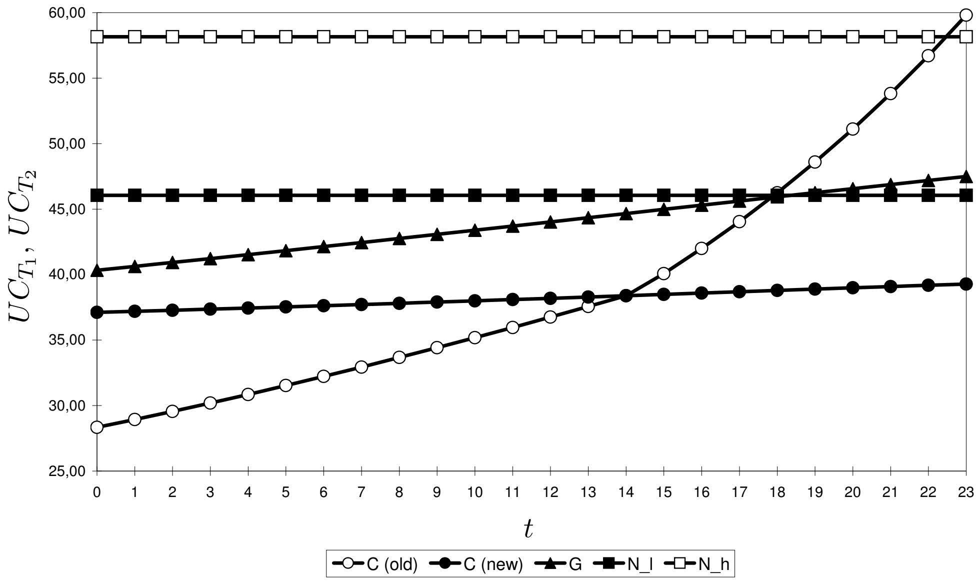

Figure 5: Unit costs of electricity of the established and new power plants under $r_p = 0.1$ in no-policy benchmark (€/MWh) (own calculations).

the technology ranking of section 4.1 immediately translates into the present replacement-time ranking.[7]

Optimal transition moment			
C	G	N_l	N_h
14.0	17.8	17.9	22.5

Table 4: Optimal moments of transition in cases of sole availability of any single new plant alternative, in years of operation of established plant from year in which analysis begins, i.e. 2015 (own calculations).

5.1.1 Sensitivity under environmental policy

Figure 6 shows the behavior of the optimal moments of transition for varying τ_e levels.

In the N_l scenario, the new coal-fired power plant remains the first option to replace the old until $\tau_e = 11.5$ €/t, with $t_{repl} \in [12.6, 14.0]$. For $\tau_e > 11.5$ €/t nuclear replaces it with $t_{repl} \in [0.0, 12.5]$, for $\tau_e \geq 23.5$ €/t immediately (i.e. in $t = 0$). Gas plays no role as first option. In the N_h scenario, the new coal-fired plant remains the first option until $\tau_e = 17.75$

[7] This is a particular case. For a different UC_{T_1} or UC_{T_2} behavior the ranking in general differs.

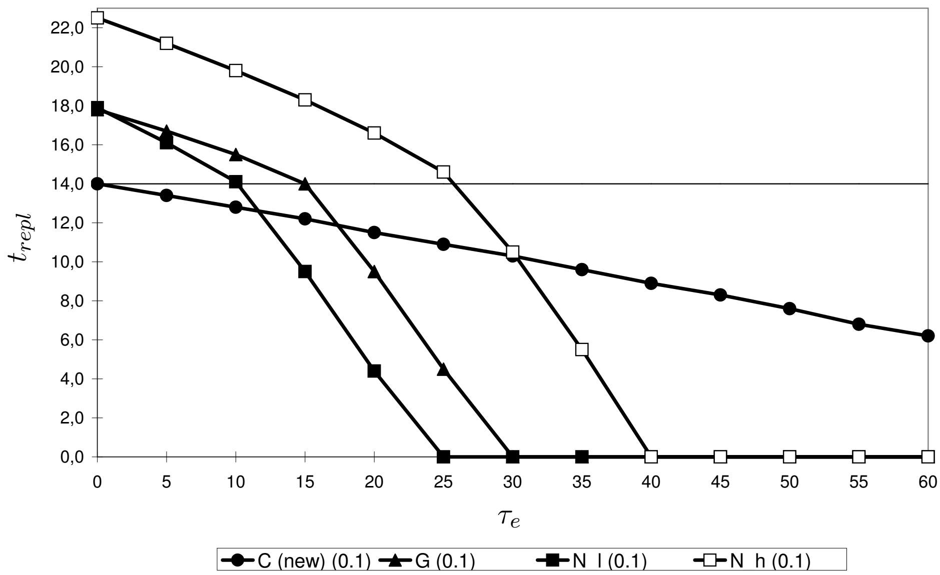

Figure 6: Optimal moments of transition to new plant alternatives for varying CO_2 prices (€/t) under $r_p = 0.1$ (own calculations).

€/t, with $t_{repl} \in [11.8, 14.0]$. For $\tau_e \in (17.75, 53.5]$ €/t gas replaces the established plant, with $t_{repl} \in [0, 11.8)$, immediately for $\tau_e \geq 28.75$ €/t. For $\tau_e > 53.5$ €/t nuclear is the first alternative, replacing the old plant immediately. The differences among the technologies mainly depend on the varied differences in emission factors and net thermal efficiencies between the established and the new technologies. Moreover, the t_{repl} shapes differ over the τ_e range, due to the particular UC_{T_1} shape over time, depending on whether the optimal moments of transition lie beyond or within the expected economic lifetime of the established plant.

5.1.2 Sensitivity under technology policy

With respect to the r_s implementation in this section two further assumption are met. It is, first, assumed to be newly introduced in $t = 0$ and, second, to apply only to the new technologies. The first assumption implies that it is not relevant for T_1 before $t = 0$, the second that it has also no direct relevance for it in $t = 0$ or later. (Its actual effect on UC_{T_1} is only marginal and therefore neglected.) Figure 7 shows the behavior of the optimal moments of transition for $r_s \in [0.02, 0.08]$. In both scenarios coal remains the first technology to replace the

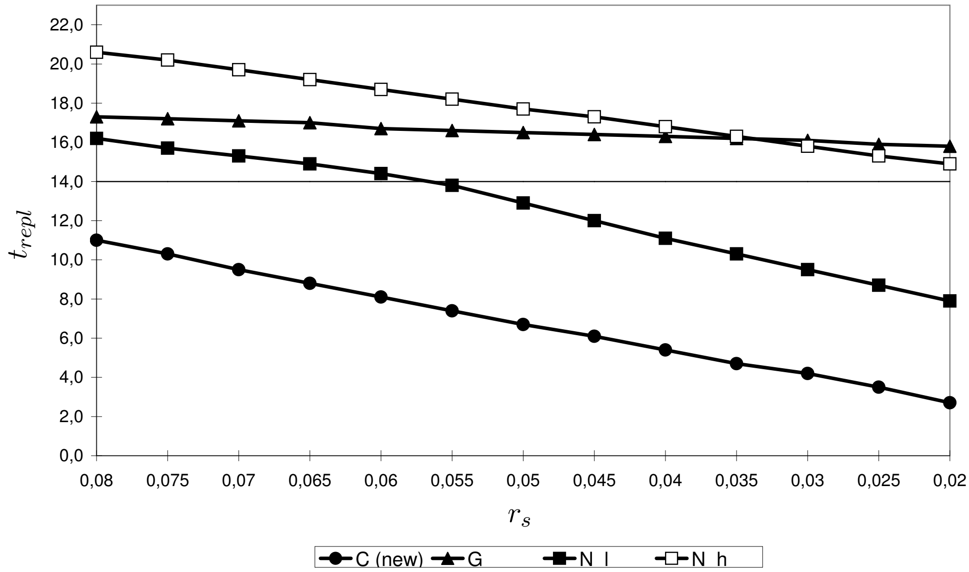

Figure 7: Optimal moments of transition to new plant alternatives for varying levels of social imputed interest rate (own calculations).

established over the whole r_s range considered, with $t_{repl} \in [2.7, 11.0]$. In the N_l scenario, the replacement-time ranking between gas and nuclear is reversed for $r_s \leq 0.08$, in the N_h scenario for $r_s < 0.034$. The varied effect of technology policy on the replacement times of the different technologies is a combined outcome of, first, its varied UC_{T_1} effect and, second, the particular shapes of the different UC_{el} curves, especially the UC_{T_1} curve. The negative UC_{T_2} impact of technology policy materialises here in the higher replacement-time reductions the flatter the UC_{T_1} curve at the place in question. For the r_s levels considered, the effect is accordingly, in general, the strongest for coal, before nuclear in the N_l scenario, nuclear in the N_h scenario, and gas. An exception to this rule is nuclear in the N_l scenario. For $r_s \in [0.02, 0.057]$, where its optimal moments of transition lie beyond the expected economic life of the established power plant, it is, in absolute terms, less strongly affected than in the N_h scenario. Moreover, for $r_s < 0.057$, where its optimal moments of transition lie within the expected economic life of the established power plant, it is, at the margin, in absolute terms, at least as strongly affected as coal, and usually more.

5.1.3 Sensitivity under environmental and technology policies

The combined influence of environmental and technology policies on the behavior of the optimal moments of transition in the N_l and the N_h scenario, respectively, over the τ_e range considered for $r_p = 0.1$ and exemplary r_s of 0.08 and 0.02 can be seen from the strong UC_{T_2} lines and their parallels in Figures 8 and 9 below. In the N_l scenario, for $r_s \in [0.02, 0.08]$ coal remains the first option until $\tau_e \in [6.0, 9.75]$ €/t, with $t_{repl} \in [1.9, 11.0]$. Above $\tau_e \in [6.0, 9.75]$ €/t, nuclear is the first option, with $t_{repl} \in [0.0, 9.6]$. In the N_h scenario, for $r_s \in [0.05, 0.08]$ coal is the first option until $\tau_e \in [18.5, 20.0)$ €/t, with $t_{repl} \in [3.8, 11.0]$, for $r_s \in [0.02, 0.05)$ until $\tau_e \in [15.0, 20.0)$ €/t, with $t_{repl} \in [0.4, 3.7)$. For $r_s \in [0.05, 0.08]$, gas is the first option for τ_e in intervals of [18.5,40.5]–20.0 €/t, with $t_{repl} \in [3.6, 8.7]$. For $r_s < 0.05$, it vanishes as first option for any τ_e. For $r_s \in [0.05, 0.08]$ nuclear follows gas as first option above $\tau_e \in (20.0, 40.5]$ €/t, for $r_s \in [0.02, 0.05)$ directly coal for $\tau_e \in (15.0, 20.0]$ €/t and higher, with $t_{repl} \in [0.0, 3.6]$. The additional technology-policy impact to environmental policy reflects the combined effect at work in the case of its sole enactment, on the different UC_{T_2} and due to the particular shapes of the different UC_{el} curves. Accordingly, the least-cost range of coal is in the N_l scenario restricted in favor of nuclear, while expanding in the N_h scenario at the expense of gas. The least-cost range of gas, persisting as first option only for higher r_s levels in the N_h scenario, is restricted from above by nuclear, which succeeds it for $r_s \in [0.05, 0.0625)$ already within the relevant τ_e range.

5.2 Replacement times with abatement technology

The end-of-pipe abatement option now fixes both UC_{T_1} and UC_{T_2} for any $\tau_e \geq AUC$ at their level for the given AUC. Graphically, it curbs the with increasing τ_e falling replacement-time curves at their level for the given AUC. Under environmental policy alone, in the N_l scenario, coal remains the first option for $AUC \leq 11.5$ €/t irrespective of τ_e, as for $\tau_e \leq 11.5$ €/t irrespective of the AUC, with $t_{repl} \in [12.6, 14.0]$ in each case. For $\tau_e, AUC > 11.5$ €/t nuclear is the first alternative. In the N_h scenario, coal dominates for $AUC \leq 17.5$ €/t irrespective of τ_e, as for any $\tau_e \leq 17.5$ €/t irrespective of the AUC, with $t_{repl} \in [11.9, 14.0]$ in each case. For $AUC \in (17.5, 53.5]$ €/t gas is the first alternative for any $\tau_e > 17.5$ €/t, as for $\tau_e \in (17.5, 53.5]$

€/t if $AUC > 17.5$ €/t, with $t_{repl} \in [0.0, 11.9]$ in each case. Nuclear is the first option for $\tau_e, AUC > 53.5$ €/t.

Figures 8 and 9 show for the N_l and the N_h scenario, respectively, the behavior of the optimal moments of transition under environmental and technology policies combined.

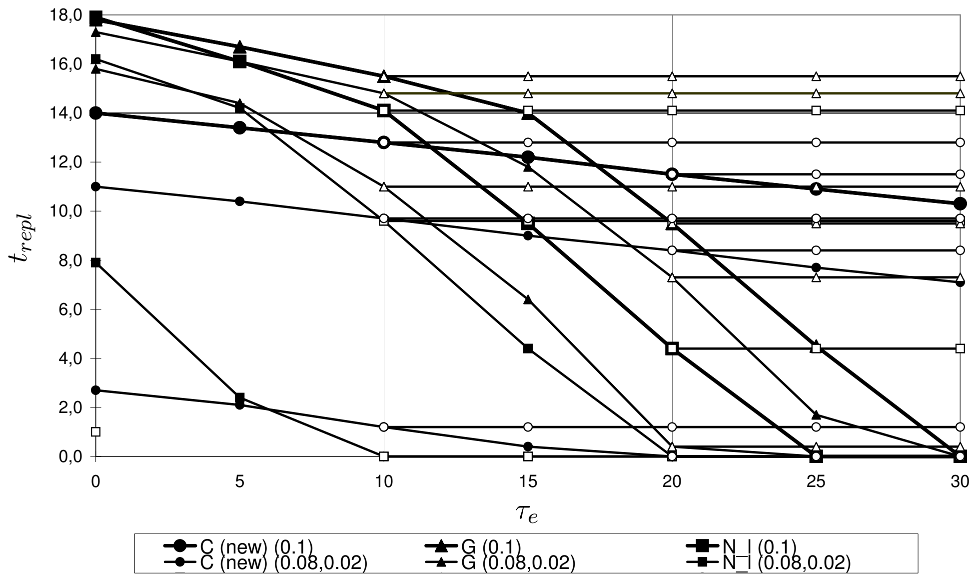

Figure 8: Optimal moments of transition to new plant alternatives for varying CO_2 prices and abatement unit cost levels between 10 and 30 €/t in steps of 10 € under $r_p = 0.1$ and social imputed interest rates of 0.08, 0.02 in N_l scenario (own calculations).

In the N_l scenario, for $r_s \in [0.02, 0.08]$ coal remains the first option until $\tau_e \in [6.0, 9.75]$ €/t, with $t_{repl} \in [1.9, 11.0]$. Above $\tau_e \in [6.0, 9.75]$ €/t, nuclear is the first option, with $t_{repl} \in [0.0, 9.6]$. Neither end-of-pipe abatement option nor CCGT technology influence the determination of the first option. In the N_h scenario, for $r_s \in [0.05, 0.08]$ coal is the first option until $AUC \in [18.5, 20.0)$ €/t irrespective of τ_e, as until $\tau_e \in [18.5, 20.0)$ €/t irrespective of the AUC, with $t_{repl} \in [3.8, 11.0]$. For $r_s \in [0.02, 0.05)$ it remains the first option until $AUC \in (15.0, 20.0]$ €/t irrespective of τ_e, as until $\tau_e \in (15.0, 20.0]$ €/t irrespective of the AUC, with $t_{repl} \in [0.4, 3.7]$. For $r_s \in [0.05, 0.08]$ gas is the first option for AUC in intervals of [18.5,40.5]–20.0 €/t and τ_e in intervals of [18.5,40.5]–20.0 €/t and higher, as for τ_e in intervals of [18.5,40.5]–20.0 €/t and AUC in intervals of [18.5,40.5]–20.0 €/t and higher, with $t_{repl} \in [3.6, 8.7]$. For $r_s < 0.05$ it vanishes as first option irrespective of τ_e and AUC. For

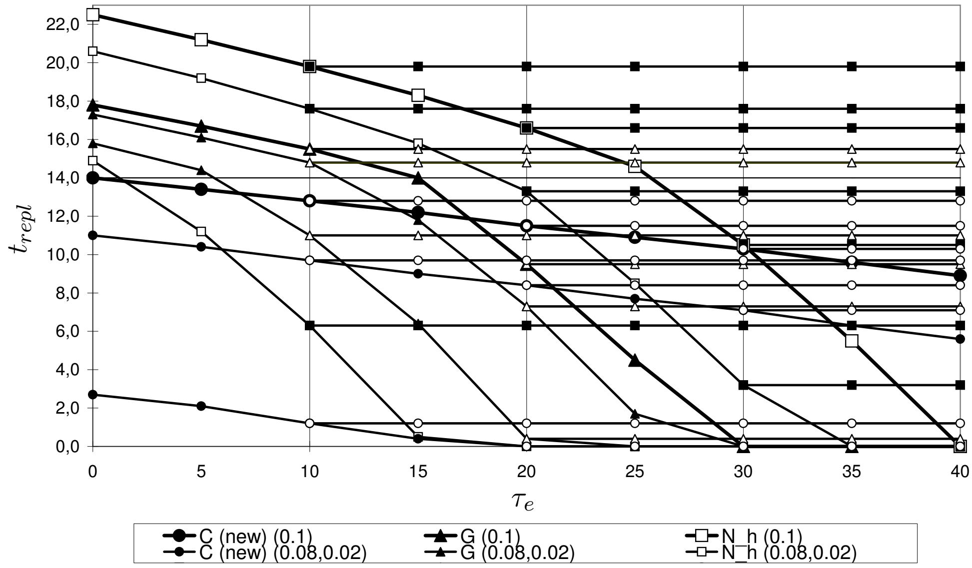

Figure 9: Optimal moments of transition to new plant alternatives for varying CO_2 prices and abatement unit cost levels between 10 and 40 €/t in steps of 10 € under $r_p = 0.1$ and social imputed interest rates of 0.08, 0.02 in N_h scenario (own calculations).

$r_s \in [0.05, 0.08]$ nuclear dominates above $\tau_e, AUC \in (20.0, 40.5]$ €/t, for $r_s \in [0.02, 0.05)$ above $\tau_e, AUC \in (15.0, 20.0]$ €/t, with $t_{repl} \in [0.0, 3.6]$. The additional technology-policy enactment to environmental policy restricts thus the scope of relevance of the abatement option to the N_h scenario, and there, while slightly expanding it for coal, further restricts it for gas to only higher r_s for less high AUC. As compared to the case without abatement technology, its availability fixes in the N_h scenario coal until low AUC and gas even until relatively high AUC for all τ_e above relatively low as first option. The scope of nuclear as first option is, accordingly, restricted only in the N_h scenario.

6 Summary and discussion of results

This section summarises and discusses the results of sections 4 and 5 in four points.

(1) Environmental policy alone raises the UC_{T_2}, the more the more polluting a technology, and reduces the replacement times, the more the cleaner the new technology as compared to the established. The technology and replacement-time rankings, of coal before gas and nuclear

in the no-policy benchmark, reverse for $\tau_e > 17.0$ (53.5) and $\tau_e > 17.5$ (53.5) €/t, respectively, in the N_l (N_h) scenario. While in the earlier studies BEI (2004) and IEA and NEA (2005) gas becomes profitable over hard coal from higher τ_e at lower r_p (30–35 €/t for $r = 0.08$, 30 €/t for $r = 0.05$, respectively), EWI and Prognos (2005) forecasts for a linearly rising τ_e until 15 €(2000)/t in 2030 a neat cut back of hard coal in favor of gas. For $\tau_e \leq 15$ €/t the latter projection occurs as roughly consistent with the present results for environmental policy alone, even including nuclear in the N_l scenario.

(2) Technology policy lowers the UC_{T_2}, the more the higher the technology-specific capital-investment costs. It also reduces the replacement times as compared to the no-policy benchmark. Due to the particular shapes of the UC_{el} curves, the latter impact is in general the strongest for coal before nuclear and gas. While coal keeps its no-policy status as first option in both the technology and the replacement-time ranking, in the former nuclear and gas reverse their order below higher r_s levels in the N_l scenario. In the latter, nuclear replaces gas as second option over the whole r_s range (below lower r_s levels) in the N_l (N_h) scenario. The distortion induced by the split imputed interest rates amounts for $r_s \in [0.02, 0.08]$ to about 1.0–12.5 (18.5) €/MWh or 2.5–27.0 (31.5)% of the distorted UC_{T_2} at the busbar in the N_l (N_h) scenario. It stays thus, e.g., neatly below the payments under the German “Erneuerbare-Energien-Gesetz” (EEG, Renewable Energy Sources Act), which prescribes feed-in tariffs for renewable energy technologies.[8] According to it, suppliers receive 457–624, 55–91, and 71.6–150 €/MWh for power from photovoltaics, wind energy, and geothermal energy, respectively.

(3) The additional enactment of technology policy to environmental policy generally favors coal, but less than nuclear. Gas is never the first option in the N_l scenario anymore. The technology and replacement-time rankings reverse, as compared to the no-policy benchmark, over the r_s range considered for $\tau_e \in [13.0, 21.0]$ ([15.0,40.5]) €/t and $\tau_e \in [18.75, 21.0]$ ([20.0,40.5]) €/t, respectively, and higher. Nuclear now competes in both rankings, for probable τ_e and r_s levels, also in the N_h scenario. This results derives departing from slightly higher CC than in IEA and NEA (2005) in the N_l, and slightly lower CC than in Enquetekommission

[8] The EEG was first enacted in April 2000, succeeding the 1991 “Stromeinspeisegesetz”, the first act to promote the introduction of renewable energies in Germany by subsidies. Its stated purpose is to increase the share of electricity from renewable energies to at least 12.5% in 2010 and 20% in 2020.

(2002) in the N_h scenario and contrasts notably to the latter study. It underlines the importance of the CC level which ultimately realises.

(4) The end-of-pipe abatement option fixes, for $\tau_e \geq AUC$, UC_{T_1} and UC_{T_2}, and with them also the replacement times, at their level for those AUC. For $\tau_e > AUC$, it thus extends the economic life of the established plant and delays the structural change. Under environmental policy, it does not affect the results for coal in the technology ranking. In the replacement-time ranking it affects them only for very low AUC. Gas is fixed as first option for sufficiently low AUC levels, of 10.0–17.0 (53.5) €/t in the N_l (N_h) scenario in the former ranking and $AUC \in (17.5, 53.5]$ €/t in the N_h scenario in the latter, for any τ_e within these ranges and higher. The additional enactment of technology policy restricts its scope of relevance in any case. Nuclear is excluded as first option for any τ_e, where the abatement option is relevant for coal or gas. The derived AUC ranges to fix a technology as first option for respective τ_e coincide only for gas in the N_h scenario with parts of its expected AUC range (section 3.2), also for technology policy. Otherwise, they stay below the relevant ranges, for coal neatly. These results confirm other studies, such as EWI and Prognos (2005), WI et al. (2007), projecting as yet only a minor role for CCS technologies in the period under consideration.

7 Conclusion

This paper studies the welfare implications of diverging social and private discount rates for investments in the German power industry around 2015 against the standard background of environmental policy. Several results of interest derive. Whether environmental policy alone induces the reversal of the no-policy technology ranking (coal before gas and nuclear) in the middle of, or well beyond the expected CO_2-price range depends on whether the low or the high nuclear cost scenario is considered. Under the hypothetic sole implementation of the social imputed interest rate coal remains the first option over the whole r_s parameter range considered. The order of gas and nuclear may reverse. The distortions implied by the diverging imputed interest rates remain moderate as compared, e.g., to the payments under the German 2000 Renewable Energy Sources Act. The additional implementation of the social imputed interest rate to environmental policy makes nuclear the first option also in the high-cost scenario for probable τ_e and r_s levels. A new end-of-pipe abatement option delays for sufficiently high τ_e the introduction of new cleaner technologies. However, according to the derived AUC ranges to fix a technology as first option only a minor role for CCS technologies is to be expected in the period under consideration.

The paper points to different issues for further research. Especially, there is thus far no systematic literature treating the causes of the split of social and private interest rates and respective policy implications. To more accurately quantify the discount-rate distortion technology-specific financing conditions should moreover be taken into account. As regards particular technologies, despite advancing research the nuclear option is to be further investigated for Germany. For a more complete comparison among relevant technological options the extension of the present analysis to renewable energy sources is desirable. Interesting differentiations to the present results could derive from the extension of the analysis in section 5 to real option values as associated with the waiting to invest in new technologies. The development of a financing model better accounting for the utilities' varied risk exposure after liberalisation remains a pending task.

Appendix

A.1 Financial model

A.1.1 Capital costs

The capital costs of a power plant comprise its capital-investment and decommissioning costs.[9] The two cost types occur before commissioning and after the end of a plant's operating life, respectively. They constitute one-time costs.

The *capital-investment costs*, CC, consist of the power plant's construction-investment costs and the imputed interest payment. The construction-investment costs, I_c, derive as the product of technology specific investment costs, I_{sp}, and net installed capacity IC_{net},

$$I_c = I_{sp} IC_{net} \ . \tag{A.1}$$

The CC are included in the annual cost analysis via the cost-accounting depreciation. Assuming straight-line depreciation, the annual amount of depreciation, $D(t)$, derives as the ${T_d}^{th}$ part of I_c, where T_d is the cost-accounting term of depreciation,

$$D(t) = \frac{I_c}{T_d} \ . \tag{A.2}$$

Economically, T_d coincides with a plant's (expected) economic life. In this paper, in accord with the applied literature, to account for the increased uncertainty after liberalisation, T_d is assumed not to exceed the planning horizon, T, of an investment project. For all technologies $T_d = 20$ is supposed.[10]

The annual imputed interest payment, $IIP(t)$, refers to the salvage value of I_c in t. Payments and depreciation are assumed to be made at the end of a period. In the first year of operation, the interest is thus paid on the full construction-investment costs. The imputed interest payment in period t is determined as

$$IIP(t) = \begin{cases} I_c(1 - \frac{t-1}{T_d})r & , \text{ if } \quad t \leq T_d \\ 0 & , \text{ if } \quad t > T_d \end{cases} , \tag{A.3}$$

where r is the real imputed interest rate, which is assumed to be constant.

The annual capital-investment costs of a power plant in period t of operation amount to

$$CC(t) = \begin{cases} \frac{I_c}{T_d}\Big(1 + (T_d - t + 1)r\Big) & , \text{ if } \quad t \leq T_d \\ 0 & , \text{ if } \quad t > T_d \end{cases} . \tag{A.4}$$

[9] In accord with the empirical data available, major refurbishment, as a type of capital cost occurring during operation, is included in the O&M costs (appendix A.1.2).

[10] This facilitates the calculations, but constitutes a simplification. The reduced depreciation term provides, to some extent, for less favorable UC_{el}, the more the higher the CC. The appropriate T_d treatment constitutes a particular issue to be clarified with respect to the systematic consideration of the utilities' varied risk exposure.

A plant's *decommissioning costs*, DC, derive as the product of the specific decommissioning costs of the technology, DC_{sp}, and net installed capacity, IC_{net},

$$DC = DC_{sp} IC_{net} \ . \tag{A.5}$$

A.1.2 Costs during operation

As costs categories incurred during a plant's economic lifetime, in this paper (i) operation and maintenance (O&M), (ii) fuel, (iii) emission, and (iv) abatement costs are distinguished.

O&M costs, OMC, include all costs for plant operation and maintenance, apart from fuel, emission, and abatement costs. Fixed specific annual O&M costs, $OMC_{fix}(t)$, comprise labor, maintenance and insurance costs per unit of IC_{net} in t. Variable specific O&M costs, OMC_{var}, consist of the costs for operating supplies other than fuel and emission costs, per amount of output produced in t, $x(t)$. The latter derives as IC_{net} times hours of full-load operation, $h_{fl}(t)$,

$$x(t) = IC_{net} h_{fl}(t) \ . \tag{A.6}$$

The O&M costs in period t can thus be determined as

$$OMC(t) = OMC_{fix}(t) IC_{net} + OMC_{var} x(t) \ . \tag{A.7}$$

Fuel costs, FC, include the costs related to fuel supply at the plant, including commodity price and transport.[11] This paper refers to the estimated (mean) fuel price, p_{fuel}, during the remaining economic life of a power plant. The annual fuel costs are further determined by the annual fuel consumption, $FCs(t)$, deriving as $x(t)$ divided by the net thermal efficiency, η_{net},

$$FCs(t) = \frac{x(t)}{\eta_{net}} \ . \tag{A.8}$$

The annual fuel costs are calculated as

$$FC(t) = FCs(t) p_{fuel} \ . \tag{A.9}$$

Emission costs, EC, are calculated as the product of annual amount of emissions generated, $E(t)$, deriving as annual fuel consumption times technology specific emission factor, f_{em},

$$E(t) = FCs(t) f_{em} \ , \tag{A.10}$$

and the emission price, $\tau_e(t)$, which is assumed to be in real terms,

$$EC(t) = \tau_e(t) E(t) \ . \tag{A.11}$$

[11] In the case of nuclear power they include all costs related to the up-stream and down-stream steps of the fuel cycle as well as the costs of transportation between the steps.

Abatement costs, AC, are calculated as the product of the annual amount of emissions generated, $E(t)$, and specific abatement costs, $AC_{sp}(t)$, per mass unit of emission,[12]

$$AC(t) = AC_{sp}(t)E(t) \ . \tag{A.12}$$

A.1.3 Unit costs of electricity generation

To determine the UC_{el}, first, the real levelised costs of electricity generation, RLC, over T are calculated. Then, they are divided by the mean annual amount of electricity generated, $\overline{x}$.

The *real levelised costs*, RLC, indicate the mean annual costs of electricity generation by a power plant in a particular year of operation during T. In this paper, following the *co-termination* approach (Bejan et al. 1996: 386f), for all investment projects a common T is chosen, equal to the expected economic life of the shortest lived alternative. In this case for any longer lived alternative the salvage value at the end of T is added to the particular project's net present value discounted with the discount rate of the last year of T. To calculate the RLC, first, the present value of the costs incurred before decommissioning, $PV_{bd}(T)$, is determined:

$$PV_{bd}(T) = \sum_{t=1}^{T} \frac{CC(t) + OMC(t) + FC(t) + EC(t) + AC(t)}{(1+r)^t} \ . \tag{A.13}$$

The corresponding RLC part derives by multiplication with the capital-recovery factor, $\frac{r(1+r)^T}{(1+r)^T-1}$ (Bejan et al. 1996: 355–357). The DC are to be levelised using the uniform-series sinking fund factor, $\frac{r}{(1+r)^{T_d}-1}$. The RLC thus amount to

$$RLC = PV_{bd}(T)\frac{r(1+r)^T}{(1+r)^T-1} + DC\frac{r}{(1+r)^{T_d}-1} \ . \tag{A.14}$$

Finally the *unit costs of electricity* of a particular reference power plant derive as

$$UC_{el} = \frac{RLC}{\overline{x}} \ . \tag{A.15}$$

A.2 Unit costs of electricity of the established technology

In general, the UC_{T_1} are determined as indicated above. As T_1 enters the analysis at some time t_1 during its time of operation and for the analysis its unit costs in that period and the following years of operation are needed, their determination is subject to some particularities. t_1 is the first year in which the new power plants could be commissioned. t_n the moment of transition to the highest-cost alternative in the no-policy benchmark. By definition, for the end of the plant's expected economic

[12] Despite the capital-cost component of the end-of-pipe abatement facility, in accord with the empirical data, in this study abatement costs are only considered as proportional to current emissions.

lifetime $t_{end} \in [t_1, t_n]$ holds. By lack of reliable empirical data in the literature, in this paper the UC_{T_1} shape in the no-policy benchmark is callibrated with respect to the following stylised indications, ceteris paribus:

(1) In t_1, the established plant is fully depreciated and financial reserves are built up for decommissioning, such that all capital costs are sunk. Over the whole of the plant's time of operation, IC_{net}, x, and, with η_{net}, also $FCs(t)$ are fixed. The $UC_{T_1}(t)$ behavior, $t \in [t_1, t_n]$, is thus only determined by the development of p_{fuel}, OMC_{fix}, and OMC_{var}. While the p_{fuel} schedule is empirically given, for the OMC_k, $k \in \{fix, var\}$, only mean values over the plant's expected economic lifetime are available in the literature.

(2) In t_1, the OMC_k, $k \in \{fix, var\}$, meet their arithmetical mean over the plant's expected economic lifetime, $\overline{OMC}_k$.

(3) In t_{end}, the UC_{T_1} are equal to the UC_{T_2} of the least-cost alternative among the new technologies, such that for $t = t_{end}$ the following equation holds:

$$UC_{T_1}(t) = \frac{OMC_{fix}(t)\, IC_{net} + OMC_{var}(t)\, \overline{x} + p_{fuel}(t)\overline{FCs}}{\overline{x}} = UC_{T_2}(t)\ . \tag{A.16}$$

(4) For any $t \in \{t_1, t_2, ..., t_n\}$, the $OMC_k(t)$, $k \in \{fix, var\}$, are determined as

$$OMC_k(t) = \overline{OMC}_k \Big(\frac{OMC_k(t_{end})}{\overline{OMC}_k}\Big)^{\frac{t-1}{t_{end}-1}}\ , \tag{A.17}$$

such that

$$\frac{1}{T_L} \sum_{t=t_{com}}^{t_{end}} OMC_k(t) = \overline{OMC}_k\ , \tag{A.18}$$

where t_{com} is the plant's year of commissioning, T_L its expected economic lifetime.

(5) In any specific year $t \in \{t_1, t_2, ..., t_{end}\}$, the $UC_{T_1}(t)$ are determined like UC_{el} in equation (A.14), with $T = t_{end} - t + 1$. In each further period $t \in \{t_{end}+1, t_{end}+2, ..., t_n\}$, the new planning horizon $T = 1$, which comes to the same as to substitute in equation (A.14) for RLC the current costs, i.e. here $OMC(t) + FC(t)$.

Under environmental policy, the UC_{T_1} are further determined by EC as well as eventual AC.

A.3 Summary of technical, financing, and cost parameters

Parameters	Unit	C (old)	C (new)	G	N_l / N_h
Technical parameters					
Year of commissioning	-	1990	2015	2015	2015
Economic life	yrs	40	40	25	40
Net installed capacity	MWe	1,500	1,500	1,500	1,500
Net thermal efficiency	-	0.45	0.51	0.60	0.37
CO_2 emission factor	t/MWh	0.338	0.338	0.200	0.0
Capacity factor	-	0.85	0.85	0.85	0.85
Electricity generated in t	TWh	10.5	10.5	10.5	10.5
Annual fuel consumption	TWh	23.3	20.6	17.5	28.3
Financing parameters					
Cost accounting term of depreciation	yrs	20	20	20	20
Planning horizon	yrs	25	25	25	25
Private imputed interest rate	-	0.1	0.1	0.1	0.1
Cost parameters					
Specific investment costs	T-€/MWe	925	1,025	500	1,800/2,600
Specific decommissioning costs	T-€/MWe	34.5	34.5	15.8	155.0
Specific annual O&M costs (fix)	T-€/MWe	40.0	36.6	18.8	30.0
Specific O&M costs (var.)	€/MWh	4.0	2.7	1.6	3.6
Mean fuel price	€/MWh	6.55	7.13	17.16	4.00
Abatement unit costs	€/t	37–70	37–70	32–65	0

Table 5: Assumptions for technical, financing, and cost parameters in year of commissioning of established and first year of availability for operation of new reference power plants as explained in the text, prices of 2005 (various sources).

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