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Abstract

We conceptualize and model the decision-making problem of an industrial investor having the choice to adopt either some cogeneration or some heat-only generating technology, or a combination of the two. The deterministic model suggested is specified in continuous time, takes a lifetime perspective, and explicitly accounts for the impact of technical change and variations in other parameters on the optimal timing to adopt a cogeneration system and the optimal capacity choice/mix. The firm is flexible in postponing the investment decision. Uncertainty is incorporated by varying energy prices and base load duration. In a sensitivity analysis we show that the optimal capacity decision can change discontinuously due to regime shifts caused by changes in key variables, making investment decisions risky (risk of a suboptimal capacity choice) and optimal policy design very challenging. In numerical simulations, we provide evidence that technical progress and other changes in other important parameters can affect the optimal timing of adoption and the optimal capacity mix in important ways. Hence, if adopters are heterogeneous, this also has important implications on the optimal diffusion path of CHP technology. At the energy policy level, our findings of discrete jumps in the optimal cogeneration capacity level call for tailored cogeneration policies according to the specific characteristics of the firms, or industrial branches. At the more general level, the model could be useful for any kind of co-production where by-products can either be sold in the market or, alternatively, used as an input in some other production process of the firm concerned.
Keywords: Cogeneration; CHP; Technology adoption; Technical change

JEL Classification: D24; D81; L11; L21; O33; Q41

1 Introduction

Combined-heat-and-power production (cogeneration, CHP) is an energy conversion technology that exploits waste heat which is otherwise released unused to the environment. Compared to the separate generation of heat and power, it allows for overall energy efficiencies of up to 90% and fuel and CO_2 emission savings in the range of 10-40%, depending on the technology used and the system replaced (for a recent survey on the various CHP technologies and their main characteristics see, e.g. Madlener and Schmid, 2003b). Therefore, CHP is considered to be a key technology for a more rational utilization of energy resources, and thus for contributing to climate change mitigation and a sustainable energy development (Metz et al., 2001; UNDP/UNDESA/WEC, 2000). Furthermore, depending on the economics of combined versus separate generation of heat and power, it may help firms to save costs and thus to improve their relative competitiveness.

Decisions on CHP investment comprise a multitude of technical and economic factors that have to be taken into account, including technical change. In liberalized energy markets in particular, risks and uncertainties concerning a number of additional, mainly market-related variables become important for the profitability of such systems, which tend to make the decision-making (adoption) process much more complex and challenging than in monopolistic markets. Nevertheless, market liberalization also tends to increase possibilities for distributed CHP generation, since grid access is facilitated and abuse of market power avenged. Other factors, particularly the heterogeneity of the firms concerned and the net benefits these firms expect to reap from adopting the technology, lead to varying degrees of delay in the adoption process, i.e. the tracing of a diffusion path over time.

Adoption and diffusion of innovative technologies has attracted the attention of economists at least since the seminal studies by Griliches (1957) on hybrid corn and Mansfield (1961) on process technologies in the manufacturing sector, respectively. Despite of this long tradition in the literature on the economics of technical change, studies on the economics of adoption and diffusion of CHP and on related regulatory and pricing issues are still rare. In this article, based on micro-economic theoretical reasoning, we analyze and model the adoption decision problem for CHP technology in continuous time, using a dynamic deterministic model set-up. We explicitly take into account technical change and

other parameters influencing the decision-making process and the optimal timing of adoption, respectively. The original contribution of this paper is essentially threefold: (1) we model the decision-maker's problem of adopting a CHP system from a lifetime perspective and in continuous time; and (2) we study the influence of technical progress on the optimal timing of adoption; we provide a model formulation that can be adopted for any kind of co-production where some by-products are involved (in our case electricity, as a by-product of useful heat) that can be either used in-house in another production process of the firm, or sold in the market.

The remainder of this article is organized as follows: Section 2 provides a review of the literature on the economics of cogeneration. In section 3, we introduce a deterministic micro-economic model of CHP adoption in continuous time, and discuss optimal operation and the choice of optimal capacity. Section 4 addresses the role of uncertainty in prices and base load duration, and section 5 the role of technical change. In section 6 we then provide some numerical simulations based on realistic parameter values, showing the sensitivity of the results with respect to variations in selected parameters. Section 7 concludes.

2 Literature review

Before turning to our own investigation and its merits and limitations, we present an overview of other work that has been done in the field of (applied) economic research on cogeneration, also illustrating the main issues addressed so far and the countries and sectors studied. For a summary of the review with further details see Table 2.

Dobbs (1983), in the context of the U.K. electricity sector, develops an early model for studying peak-load pricing and capacity planning for CHP installations facing different market structures, and for analyzing the implications of the different market structures for electricity and heat pricing.

Joskow and Jones (1983) study optimal decision making of a representative cost-minimizing industrial firm that wants to invest in CHP technology. They develop a series of simple to more complicated CHP adoption models, aiming to identify the interactions among incremental investment costs, fuel and electricity prices, steam load characteristics, and plant scale. All of the mentioned variables not only affect the decision to cogenerate,

but also the level of CHP capacity a firm would consider economical to install. In Joskow (1984) the author builds upon his earlier work and empirically studies the situation for the pulp and paper industry in several U.S. states.

Anandalingam (1985) introduces a dynamic partial equilibrium model that includes peak-load pricing and social welfare impacts, and then applies it to selected industries of the U.S. economy. The model is used to study investment behavior and investment policy impacts (tax credits) as well as to undertake policy simulations.

In contrast, Zweifel and Beck (1987) deal with the pricing behavior of utilities for electricity fed into the grid by cogenerators, studying the Averch-Johnson effect of over-capitalization. In the given context this effect implies that capital invested by independent power producers detracts from the allowable base of rate-of-return regulated utilities. The authors further address regulatory issues arising in the context of the U.S. 1978 Public Utility Regulatory Policies Act (PURPA).

Woo (1988) also tackle the rate design problem of cogenerated electricity fed into the grid. In particular, the author studies the inefficiency of avoided cost pricing rules for cogenerated power in the context of PURPA, by undertaking a social welfare analysis based on the three components consumer surplus, cogenerator profit, and utility profit.

Fox-Penner (1990) investigates the implications of PURPA, state-level regulation, and state average fuel and electricity prices on the overall investment in CHP technology by independent power producers. For the analysis the author uses a probabilistic cost-minimizing CHP investment model, which – due to a lack of firm-level data – he applies at the state level.

Kwun and Baughman (1991) study the joint planning (optimal capacity expansion and operation) of industrial CHP and electricity production by utilities with a set of dynamic optimization (cost-minimization) models. In particular, the authors investigate the impact of six different levels of buy-back rate on the optimal level of self-generation.

Rose and McDonald (1991) develop a structural micro-econometric model for analyzing the influence of various economic and engineering variables on the CHP adoption behavior in the U.S. chemical and pulp industries. Their main focus is on the derived demand for electricity, price of purchased electricity, and marginal cost of self-generation.

Dismukes and Kleit (1999) focus on the modeling of the determinants of CHP utilization by commercial generators and self-generators in one of the U.S. states (Louisiana) under conditions of electricity market restructuring. In particular, they use an econometric electricity demand model and two discrete choice models to determine the impact of a number of technical and economic variables on the decision to install a CHP system.

Strachan and Dowlatabadi, in a series of papers, look at various aspects related to the adoption of engine-CHP systems in the U.K. (Strachan and Dowlatabadi, 1999a,b, 2002, the latter also covers the situation in the Netherlands). They use engineering-economic analysis and simple net present value models to study barriers and technology supplier strategies, profitability of CHP investments by size of installation, and financing aspects.

Bonilla et al. (2002, 2003) study the determinants of CHP adoption in the manufacturing industry. In their first study, the authors introduce an econometric model specification for CHP adoption in the context of deregulation of the Japanese power market and base their analysis on time series cross-section panel data for seven sectors of the manufacturing industry in Japan. In contrast, in a second study, the authors use survey-derived plant level data for descriptive diffusion analysis and undertake some econometric estimation with selected binary choice model formulations.

Kwon and Yun (2003), with the help of a non-parametric linear programming model, empirically estimate the existence and level of economies of scope of CHP systems, as compared to separate heat and power production. Their analysis is focused on urban CHP systems in Korea (Seoul metropolitan area) and includes annual expenditures on the input cost variables capital, labor, and fuel.

Madlener and Schmid (2003a) investigate the adoption and diffusion of engine-CHP systems in Germany. In particular, based on a rich micro-data set for Germany for the period 1960-1998, they introduce parametric, semi-parametric, and non-parametric hazard rate model formulations for CHP adoption and diffusion. Moreover, the authors undertake comparative (standard) NPV calculations for small and large engine-CHP systems and provide a thorough descriptive data analysis.

Finally, Wickart and Madlener (2007) model industrial CHP adoption under uncertainty, applying real options theory and a dynamic stochastic model. The authors study

the decision between an irreversible investment in a CHP system and the alternative of investing in a conventional heat-only generation system (and obtaining all electricity from the grid). In a numerical example the model is applied to stylized data, using realistic cost values. The stochastic model formulation adopted contrasts with the deterministic set-up in the present paper, and illustrates nicely the trade-offs and limits involved in both approaches.

None of the above-mentioned studies has aimed at simultaneously modeling the adoption of CHP in sufficient techno-economic detail and at the same time safeguarding an analytical solution of the model in continuous time. Moreover, as far as we are aware of, none of these studies has studied the intertemporal choice between a traditional and a new technology, or a combination of the two, in a deterministic setting.

Outside the energy economics domain, intertemporal technology adoption models have typically focused on vintage human and/or physical capital (e.g. Chari and Hopenhayn, 1991); learning effects on the supply side (e.g. Jovanovic and Lach, 1989), demand side (e.g. Stoneman and Ireland, 1983), or on both sides (e.g. Vettas, 1998); learning and obsolescence costs (Parente, 1994); and strategic interaction (e.g. Reinganum, 1981a,b). The arrival and adoption value of the new technology is either treated as certain or uncertain. The seminal paper on technology adoption timing under uncertainty is Jensen (1982). Balcer and Lippman (1984) and Weiss (1994) study uncertainty related to the date of market launch and value of a new technology, which can lead to delayed adoption of an already available technology.[1] Note that most of the models focusing on the optimal timing of technology adoption are theoretical and highly stylized (for a useful recent survey of the literature see Hoppe, 2002, among others).

[1]Real options (RO) models of irreversible technology adoption under uncertainty (e.g. Dixit and Pindyck, 1994) are stochastic models that account for the value of waiting accruing from the flexibility of postponing the investment. Examples of RO models applied to the adoption of new technology are Farzin et al. (1998); Doraszelski (2001, 2004)

Table 1: Summary of the economics cogeneration literature surveyed

Study	*Scope of research (Country)*	*Data*	*Type of model, research focus*
Dobbs (1983)	Generic CHP (U.K.)	-	Theoretical peak-load pricing model; pricing implications of different market structures
Joskow and Jones (1983)	Ind. CHP (U.S.)	Stylized	Cost minimization model; optimal decision-making of a representative industrial firm
Joskow (1984)	Ind. CHP (U.S. pulp & paper ind., sel. states)	1972, 1977, 1980	Cost minimization model; optimal decision-making of a representative industrial firm
Anandalingam (1985)	Ind. CHP (U.S., selected branches)	-	Dynamic partial equilibrium model; CHP investment policy (tax credits) impact simulations
Zweifel and Beck (1987)	Comm. CHP (U.S.)	-	Theoretical model; utilities' pricing behavior for CHP electricty fed into the grid, regulatory issues
Woo (1988)	Generic CHP (U.S.)	-	Theoretical model; efficient pricing, rate design
Fox-Penner (1990)	Generic CHP (U.S., state-level analysis)	1985 (49 obs.)	Econometric model; cost-minimizing investment decision, interstate regulatory differences
Kwun and Baughman (1991)	Ind. CHP	Stylized	OR model; impact of buy-back rate, joint planning of industrial CHP and electricity supply by utilities
Rose and McDonald (1991)	Ind. CHP (U.S. chemical and paper industries)	1985	Structural micro-econometric model; economic determinants of industrial CHP
Dismukes and Kleit (1999)	Ind. CHP(U.S., Louisiana)	1995 (260 obs.)	Econometric electricity demand and discrete choice models; determinants of CHP generation
Strachan and Dowlatabadi (1999b)	Engine-CHP (U.K.)	1992-97 (630 obs.)	NPV model; analysis of barriers and technology supplier strategies
Strachan and Dowlatabadi (1999a)	Engine-CHP (U.K.)	1992-97 (600 obs.)	NPV model; economics (profitability) of engine-CHP adoption
Strachan and Dowlatabadi (2002)	Engine-CHP (The Netherlands, U.K.)	1985-98	Engineering-economic analysis; cross-country comparison, adopter–utility partnerships, supplier strategies, institutional change
Bonilla et al. (2002)	Ind. CHP (Japan, 7 industries)	1985-98 (1'500 obs.), TS-CS[a] panel data	Log-linear and discrete choice model; determinants of CHP adoption, economies of scale
Bonilla et al. (2003)	Ind. CHP (Japan, manufacturing sector)	1980-2000, plant-level data	Econometric binary choice model; determinants of CHP adoption, technological substitution
Kwon and Yun (2003)	Generic CHP (Korea, Seoul metropolitan area)	1991-99 (39, 6 and 9 obs.)	Non-parametric LP[b] model; economies of scope
Madlener and Schmid (2003a)	Engine-CHP (Germany)	1960-98 (4'921 obs.)	NPV model, hazard rate models; determinants of CHP adoption, interstate differences in adoption patterns
Wickart and Madlener (2007)	Ind. CHP (Switzerland)	Stylized	Dynamic stochastic (real options) model; optimal technol. choice and investment timing
(this study)	Ind. CHP (Switzerland)	Stylized	Dynamic deterministic (NPV) model; optimal technol. choice and investment timing

[a] Time series-cross sectional.
[b] Linear programming.

3 A micro-economic model of cogeneration adoption

Our model is designed to analyze optimal CHP adoption given certain technological expectations. The choice of the optimal technology mix depends on its lifetime costs, which depend on the operation of the system. Therefore, we first have to specify the cost components and the optimal operation of a given energy system.

The analysis proceeds through two steps. First, we derive the instantaneous variable cost function for a given steam boiler and cogeneration capacity. This allows us to determine optimal dispatching that minimizes instantaneous variable costs. In a second step, we choose a simplified heat and electricity load demand profile. In order to get analytical results, we keep other parameters fixed. We can then integrate the instantaneous variable cost function under optimal dispatching over the whole lifetime of the plant, in order to derive the discounted total variable costs. The optimal capacity mix is given by minimizing total costs, consisting of fixed operating and maintenance (O&M) costs, investment costs and discounted total variable costs. Throughout the analysis, we assume that the firm must meet its heat demand at all times, and that it is not connected to a district heating network (i.e. there is no opportunity for external heat purchases or sales). Furthermore, in order to simplify the analysis further, we assume that thermal and electrical efficiencies are not affected by the current load of the system, and we disregard costs that accrue from stopping and (re-)starting the system.

For addressing the uncertainties inherent in the economic variables, such as energy prices, or uncertainties in operation, such as base load duration, we perform parameter variations and analyze the impact on the optimal capacity choice. Of course, a more sophisticated analysis of the impacts of underlying risks would require more extensive numerical simulation models. Based on numerical simulation, the model could also be embedded into a real options framework (cf. Wickart and Madlener, 2007).

Finally, we applied the model developed for analyzing optimal CHP adoption under different expectations of technological progress.

3.1 Instantaneous cost function and optimal operation

For fixed capacities, the firm minimizes its instantaneous variable costs: the cost of fuel as an input for the heat and electricity generation process, other variable operation and maintenance costs, and electricity costs. The fuel costs per heat unit produced for both subsystems $i = \{SB, CG\}$, c_F^i, are defined as

$$c_F^i = \frac{p_F}{\eta_H^i},$$

where p_F denotes current fuel price and η_H^i the thermal efficiency of system i. Since $\eta_H^{SB} > \eta_H^{CG}$ the fuel costs per unit of heat for a steam boiler are lower than those of a cogeneration system. For simplicity, we assume that the unit variable operation and maintenance costs, c_{OM}^i, are linear in heat production, i.e. $c_{OM}^i = \gamma^i$, where γ_i is constant for system i. Finally, the electricity costs depend on the level of self-generation of electricity and the firm's electricity needs. If the firm's electricity needs, L_E, are higher than the self-generated electricity, it has to buy electricity from the grid at rate p_E (the purchase price). On the other hand, the firm can sell excess electricity to the grid at the buy-back rate b. The electricity costs per heat unit are therefore defined as:

$$c_E^i(\theta^{CG}, \lambda) = \begin{cases} p_E(\lambda - \theta^{CG} s^{CG}) & \text{if } \lambda \geq \theta^{CG} s^{CG} \\ -b(\theta^{CG} s^{CG} - \lambda) & \text{if } \lambda < \theta^{CG} s^{CG} \end{cases},$$

where $\lambda \equiv \frac{L_H}{L_E}$ is the heat intensity of the firm, i.e. the ratio between the firm's heat demand and electricity demand, $s^i \equiv \frac{\eta_E^i}{\eta_H^i}$ is the electricity rate, defined as the ratio between electrical efficiency and thermal efficiency, and $\theta^{CG} = \frac{L_H^{CG}}{L_H}$ is the fraction of heat produced by cogeneration relative to total heat demand, which depends on the dispatching decision. Note that since $\eta_E^{SB} = 0$, the electricity rate of a steam boiler is equal to zero.

Collecting all cost components gives the instantaneous unit variable heat costs:

$$c_H(\theta^{CG}, \theta^{SB}, \lambda) = c_E(\theta^{CG}, \lambda) + \sum_i \theta^i (c_F^i + c_{OM}^i).$$

Since we assume that heat supply always matches heat demand we have $\theta^{CG} + \theta^{SB} = 1$. Thus, we can rewrite the summation term on the right-hand side of the equation in terms of θ^{CG} and λ:

$$c_H(\theta^{CG}, \lambda) = c_E(\theta^{CG}, \lambda) + \theta^{CG}(c^{CG} - c^{SB}) + c^{SB}, \tag{1}$$

where $c^i \equiv c^i_F + c^i_{OM}$. Since Eq. (1) is linear in θ^{CG}, the minimal unit heat costs are a boundary solution. Differentiating the instantaneous unit heat cost function with respect to installed cogeneration capacity yields the marginal unit heat cost of cogeneration:

$$\frac{\partial c_H(\theta^{CG}, \lambda)}{\partial \theta^{CG}} = (c^{CG} - c^{SB}) + \frac{\partial c_E(\theta^{CG}, \lambda)}{\partial \theta^{CG}}. \tag{2}$$

The first term in brackets on the right-hand side in Eq. (2) denotes the additional variable unit costs induced by increasing the current load of cogeneration marginally, whereas the second term expresses the induced electricity cost savings. The marginal unit electricity costs of cogeneration are given as:

$$\frac{\partial c_E(\theta^{CG}, \lambda)}{\partial \theta^{CG}} = \begin{cases} -p_E s^{CG}, & \text{if } \lambda \geq \theta^{CG} s^{CG} \\ -b s^{CG}, & \text{if } \lambda < \theta^{CG} s^{CG} \end{cases}.$$

In the following we assume that the electricity price p_E is higher than the buy-back rate, since the electricity price also includes services provided by the grid operator. Of course, if policy-makers aim at fostering cogeneration by setting the buy-back rate sufficiently high, the inequality might reverse. In this case, optimal dispatching changes as well and, therefore, also lifetime variable costs, which will influence the optimal capacity choice.

The optimal dispatching of the cogeneration unit is restricted to the interval $\hat{\theta}^{CG} \in [0, \min\left\{1, \bar{\theta}^{CG}\right\}]$, where $\bar{\theta}^{CG} \equiv \frac{\bar{L}^{CG}_H}{L_H}$ is the ratio of installed cogeneration heat capacity relative to the current heat demand of the firm. If the marginal unit costs $(c^{CG} - c^{SB}) - p_E s^{CG}$ are positive, then the variable costs of cogeneration are higher than those of a steam boiler and buying electricity from the grid is preferable (if the marginal costs are zero, the firm is just indifferent). Since the investment is irreversible and the heat demand of the firm must be met, cogeneration is only operated if the firm's heat demand exceeds the installed capacity of the steam boiler. Therefore, the optimal dispatching $(\hat{\theta}^{CG}, \hat{\theta}^{SB})$ is equal to $(1 - \hat{\theta}^{SB}, \min\left\{1, \bar{\theta}^{SB}\right\})$ where $\bar{\theta}^{SB}$ is the ratio between installed steam boiler capacity and current heat demand.

On the other hand, if the marginal unit costs $(c^{CG} - c^{SB}) - p_E s^{CG}$ are below zero, then running the CHP system might contribute to the recovering of additional fixed and investment costs induced by cogeneration. We have to distinguish two cases: (i) the marginal unit costs of cogeneration of a net electricity supplier are less than or equal to

zero, i.e. $(c^{CG} - c^{SB}) - bs^{CG} \leq 0$ and (ii) the marginal unit costs of cogeneration of a net electricity supplier are greater than zero, i.e. $(c^{CG} - c^{SB}) - bs^{CG} > 0$. In the first case, and since we have assumed that $p_E \geq b$, it is always economical to operate the cogeneration system at its full capacity, if possible. Thus, the optimal dispatching $(\hat{\theta}^{CG}, \hat{\theta}^{SB})$ is equal to $(\min\left\{1, \bar{\theta}^{CG}\right\}, 1 - \hat{\theta}^{CG})$. In the second case, optimal dispatching depends on the size of the cogeneration system. If it is small enough such that electricity demand is always higher than self-generated electricity, it is also optimal to operate the CHP unit at full capacity, if possible. On the other hand, if the electric capacity of the CHP unit is greater than electricity demand, self-generated electricity is restricted to the firm's demand for electricity. Therefore, the optimal dispatching policy $(\hat{\theta}^{CG}, \hat{\theta}^{SB})$ is equal to $(\min\left\{1, \bar{\theta}^{CG}, \frac{\lambda}{s^{CG}}\right\}, 1 - \hat{\theta}^{CG})$. Table 2 provides an overview of the three possible cases and related optimal dispatching policies.

3.2 Variable cost function

Current energy prices and the heat and electricity loads determine the instantaneous cost function and therefore the optimal dispatching. In order to determine the optimal capacity of the CHP system, however, we must also derive the net present value of the variable costs during the whole lifetime of the system. Thus, we have to integrate the instantaneous cost function over time, using the time paths of fuel and electricity price, electricity buy-back rates, and heat and electricity demand. In order to get an analytical solution, we assume constant prices and buy-back rates. Under this assumption, if marginal unit heat costs of cogeneration are positive, the optimal capacity of cogeneration is equal to zero (see Eq. (2)). Thus, we only consider the case where marginal unit heat costs of cogeneration are below zero.

Heat and electricity demand over time is assumed to follow a periodic pattern. In each period of length T we have a base-load heat demand, $L_{H,B}$, of length $t_B \leq T$ and a peak-load heat demand, $L_{H,P} > L_{H,B}$:

$$L_H(t) = \begin{cases} L_{H,B}, & \text{if } t \leq t_B \\ L_{H,P}, & \text{if } t > t_B \end{cases} .$$

For simplicity we assume a constant electricity load demand, i.e. $L_E(t) = \bar{L}_E$, and that

Table 2: Optimal dispatching of the cogeneration unit

Case	*Optimal dispatching rule* $(\hat{\theta}^{CG}, \hat{\theta}^{SB})$	*Comments*
$(c^{CG} - c^{SB}) - p_E s^{CG} \geq 0$	$(1 - \hat{\theta}^{SB}, \min\left\{1, \bar{\theta}^{SB}\right\})$	Additional installation and fixed costs of CHP can not be recovered; CHP system operation only if needed to meet heat load
$(c^{CG} - c^{SB}) - p_E s^{CG} < 0$		CHP system operation contributes to recover additional installation and fixed costs
Subcase (i):		
$(c^{CG} - c^{SB}) - bs^{CG} \leq 0$	$(\min\left\{1, \bar{\theta}^{CG}\right\}, 1 - \hat{\theta}^{CG})$	Marginal costs of a net electricity supplier are non-positive; CHP system operation at full capacity since selling excess electricity is profitable
Subcase (ii):		
$(c^{CG} - c^{SB}) - bs^{CG} > 0$	$(\min\left\{1, \bar{\theta}^{CG}, \frac{\lambda}{s^{CG}}\right\}, 1 - \hat{\theta}^{CG})$	Marginal costs of a net electricity supplier is positive; optimal dispatching is size-dependent; if possible, only generate electricity in order to meet firm's electricity demand

there are no scheduled or unscheduled outages (i.e. the plant is in operation 8'760 hours a year).[2] The former implies a heat intensity, λ, of

$$\lambda(t) = \begin{cases} \lambda_B \equiv \frac{\bar{L}_E}{L_{H,B}}, & \text{if } t \leq t_B \\ \lambda_P \equiv \frac{\bar{L}_E}{L_{H,P}}, & \text{if } t > t_B \end{cases} .$$

We choose parameters such that $s^{CG} L_{H,P} \geq \bar{L}_E \geq s^{CG} L_{H,B}$. Hence, depending on the installed cogeneration capacity, the firm might become a net supplier of electricity.

The optimal dispatching depends on whether supplying excess electricity to the grid is profitable or not. We first derive the net present value of the total variable cost function for the case where supplying excess electricity to the grid is unprofitable.

The optimal dispatching depends on the installed cogeneration capacity, $\bar{L}_H^{CG}$. If the installed cogeneration capacity is less than the base load, then the cogeneration system is operated at full capacity (since we assume that $\bar{L}_E \leq s^{CG} L_{H,B}$), i.e.

$$\hat{\theta}^{CG} = \begin{cases} \frac{\bar{L}_H^{CG}}{L_{H,B}}, & \text{if } t \leq t_B \\ \frac{\bar{L}_H^{CG}}{L_{H,P}}, & \text{if } t > t_B \end{cases} .$$

If the installed cogeneration capacity is higher than the base load, $\bar{L}_H^{CG} > L_{H,B}$, but the amount of self-generated electricity is still lower than electricity demand, $s^{CG} \bar{L}_H^{CG} \leq \bar{L}_E$, then the cogeneration system is still operated at full capacity, if possible, i.e.:

$$\hat{\theta}^{CG} = \begin{cases} 1, & \text{if } t \leq t_B \\ \frac{\bar{L}_H^{CG}}{L_{H,P}}, & \text{if } t > t_B \end{cases} .$$

Finally, if installed cogeneration capacity enables the firm to produce excess electricity during peak-load heat demand periods, then the optimal dispatching of the CHP system is restricted such that the firm does not become a net supplier of electricity:

$$\hat{\theta}^{CG} = \begin{cases} 1, & \text{if } t \leq t_B \\ \frac{\lambda_P}{s^{CG}}, & \text{if } t > t_B \end{cases} .$$

[2] In real life applications typical operating hours of industrial CHP units may be up to 8'200 hours. The nature of the results are not expected to change significantly by adding the complications of either outages or ramp-up and shut-down times. Our main focus here, however, is more on the optimal adoption of a new technology, rather than optimal dispatching.

Plugging the optimal dispatching policy rules into the instantenous unit variable cost function and multiplying with the current heat demand yields the instantaneous total variable cost function, which can be integrated over time (see Appendix). Using a discount rate r, this yields the net present value of the variable costs during the full lifetime of the system, the latter of which is assumed to be infinite in order to simplify the analysis. The net present value of the total variable costs depends on the installed cogeneration capacity. It can be shown that the net present value of total variable costs is continuous and piecewise differentiable. The derivative is given by

$$\frac{dC(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} = \begin{cases} \frac{c^{CG}-c^{SB}-p_E s^{CG}}{r}, & \text{if } \bar{L}_H^{CG} \leq L_{H,B} \\ \frac{e^{-rt_B}-e^{-rT}}{r(1-e^{-rT})}(c^{CG}-c^{SB}-p_E s^{CG}), & \text{if } \bar{L}_H^{CG} > L_{H,B},\ s^{CG}\bar{L}_H^{CG} \leq \bar{L}_E \\ 0, & \text{if } s^{CG}\bar{L}_H^{CG} > \bar{L}_E \end{cases} \tag{3}$$

If the cogeneration capacity is less than or equal to base load, then we have a constant stream of cost savings, $c^{CG}-c^{SB}-p_E s^{CG}$, for recovering the additional fixed operating and investment costs incurred by the CHP system. If the cogeneration system cannot always be operated at full capacity but no excess electricity is produced when operated at full capacity, then the contribution is decreased since for $t_B > 0$, $\frac{e^{-rt_B}-e^{-rT}}{r(1-e^{-rT})} < \frac{1}{r}$. Finally, if the cogeneration capacity is such that the firm produces excess electricity at full capacity operation, then there is no contribution to recovering fixed operating and investment costs, since it is not profitable to sell electricity to the grid.

If it becomes profitable to sell excess electricity to the grid, then the optimal dispatching policy changes if cogeneration capacity is sufficiently high, i.e. $s^{CG}\bar{L}_H^{CG} > \bar{L}_E$. In this case it is optimal to operate the cogeneration system always at full capacity, i.e.

$$\hat{\theta}^{CG} = \begin{cases} 1, & \text{if } t \leq t_B \\ \frac{\bar{L}_H^{CG}}{\bar{L}_{H,P}}, & \text{if } t > t_B \end{cases} .$$

Going through the same steps as above we obtain the derivative of the discounted total variable costs with respect to installed cogeneration capacity,

$$\frac{dC(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} = \begin{cases} \frac{c^{CG}-c^{SB}-p_E s^{CG}}{r}, & \text{if } \bar{L}_H^{CG} \leq L_{H,B} \\ \frac{e^{-rt_B}-e^{-rT}}{r(1-e^{-rT})}(c^{CG}-c^{SB}-p_E s^{CG}), & \text{if } \bar{L}_H^{CG} > L_{H,B},\ s^{CG}\bar{L}_H^{CG} \leq \bar{L}_E \\ \frac{e^{-rt_B}-e^{-rT}}{r(1-e^{-rT})}(c^{CG}-c^{SB}-bs^{CG}), & \text{if } s^{CG}\bar{L}_H^{CG} > \bar{L}_E \end{cases} . \tag{4}$$

Since net supply of electricity is profitable, the firm can contribute to fixed operating and investment costs by supplying electricity to the grid during peak load heat periods.

3.3 Choice of optimal capacity combination

The firm has to determine the optimal combination between cogeneration and steam boiler capacity. The optimal cogeneration capacity is determined by the cost minimizing capacity mix. Total costs include the lifetime variable costs, fixed operating and maintenance costs, and investment costs. We assume that fixed O&M costs and investment costs are concave in capacity due to economies of scale. The optimal capacity of cogeneration is determined by solving the cost minimization problem

$$\begin{aligned} \min_{\bar{L}_H^{CG},\bar{L}_H^{SB}} \quad & C(\bar{L}_H^{CG}) + \sum_i \bar{C}_{OM}^i(\bar{L}_H^i) + I^i(\bar{L}_H^i) \\ \text{s.t.} \quad & \sum_i \bar{L}_H^i = L_{H,P} \\ & \bar{L}_H^i \geq 0, \end{aligned}$$

where $\bar{C}_{OM}^i$ are fixed O&M costs and I^i the investment costs of system i. Substituting for the restriction in the objective function yields:

$$\begin{aligned} F(\bar{L}_H^{CG}) &= C(\bar{L}_H^{CG}) + \bar{C}_{OM}^{SB}(L_{H,P} - \bar{L}_H^{CG}) + \bar{C}_{OM}^{CG}(\bar{L}_H^{CG}) \\ &\quad + I^{SB}(L_{H,P} - \bar{L}_H^{CG}) + I^{CG}(\bar{L}_H^{CG}) \end{aligned}$$

and the first derivative is given as

$$\begin{aligned} \frac{dF(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} &= \frac{dC(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} - \frac{\bar{C}_{OM}^{SB}(L_{H,P} - \bar{L}_H^{CG})}{\bar{L}_H^{CG}} + \frac{d\bar{C}_{OM}^{CG}(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} \\ &\quad - \frac{I^{SB}(L_{H,P} - \bar{L}_H^{CG})}{d\bar{L}_H^{CG}} + \frac{I^{CG}(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}}. \end{aligned} \tag{5}$$

Since the derivative of the lifetime total variable costs is discontinuous, we have to check the boundaries and the points where the jumps in the derivative appear. Thus, possible

minima are given by the following conditions:

Lower boundary $\bar{L}_H^{CG} = 0$:	$\frac{dF(0)}{d\bar{L}_H^{CG}} \geq 0$
First inflection point $\bar{L}_H^{CG} = L_{H,B}$:	$\lim_{\bar{L}_H^{CG} \to L_H^{B-}} \frac{dF(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} \leq 0$ and
	$\lim_{\bar{L}_H^{CG} \to L_H^{B+}} \frac{dF(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} \geq 0$
Second inflection point $\bar{L}_H^{CG} = \frac{\bar{L}_E}{s^{CG}}$:	$\lim_{\bar{L}_H^{CG} \to \frac{\bar{L}_E}{s^{CG}}^-} \frac{dF(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} \leq 0$ and
	$\lim_{\bar{L}_H^{CG} \to \frac{\bar{L}_E}{s^{CG}}^+} \frac{dF(\bar{L}_H^{CG})}{d\bar{L}_H^{CG}} \geq 0$
Upper boundary $\bar{L}_H^{CG} = L_{H,P}$:	$\frac{dF(L_{H,P})}{d\bar{L}_H^{CG}} \leq 0$

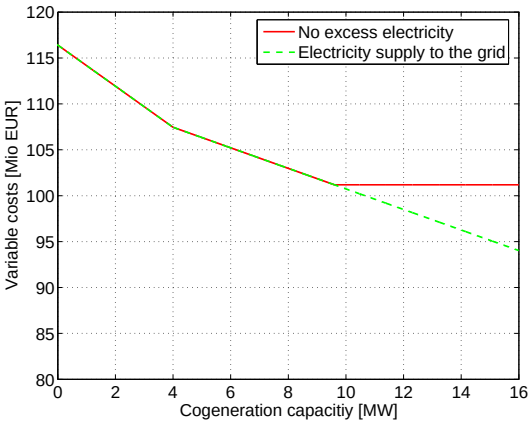
Before turning to the role of technical progress on the optimal capacity choice, we study first the impact of uncertainty in prices and base load duration by parameter variations, using a numerical example.

4 Uncertainty in prices and base load duration

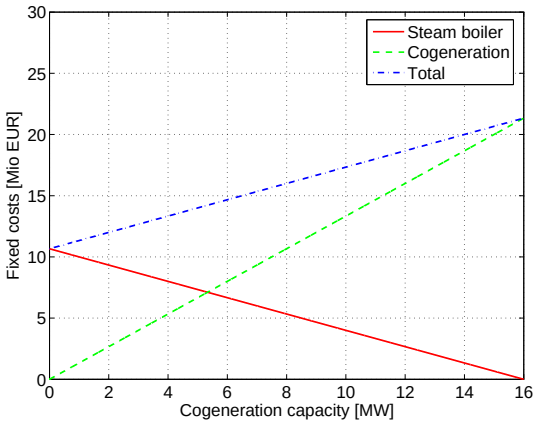
We investigate the optimal capacity and the total cost functions. Therefore, we also have to explicitly specify the fixed costs and investment costs functions. Using the parameter values reported in Table 3, the discounted variable costs turn out as shown in Figure 1(a) for alternative levels of the buy-back rate. If the buy-back rate is sufficiently high the variable costs decrease as cogeneration capacity increases. However, at lower buy-back rates excess electricity generation is not profitable and the variable cost curve levels off at a certain capacity level. In fact this has important policy implications: if energy policy aims to induce investors to install CHP capacity beyond the self-generation level, then policy makers have to ensure that the buy-back rate exceeds a critical threshold level. For the fixed costs we assume constant costs per installed unit of (thermal) capacity. Figure 1(b) shows the discounted fixed costs of the heat generation system with respect to the size of the installed cogeneration unit.

The investment costs in absolute terms are determined by the specific investment costs, which decline at a decreasing rate, as shown in Figure 2(a). Figure 2(b) shows the resulting total investment costs as a function of the capacity mix chosen.

We have shown above that the optimal CHP capacity depends on the time profile of the heat demand and the heat demand intensity. Next we analyze the sensitivity of the

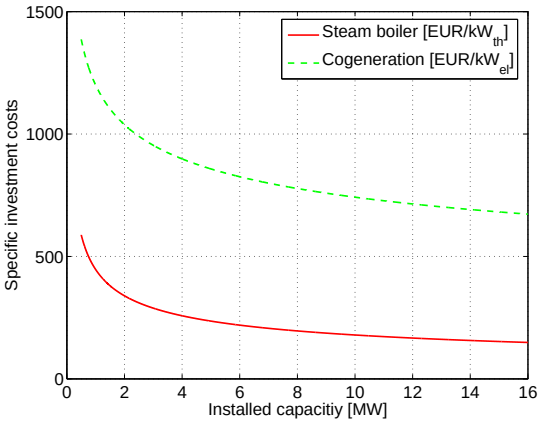


(a) Variable costs, high/low buy-back rates

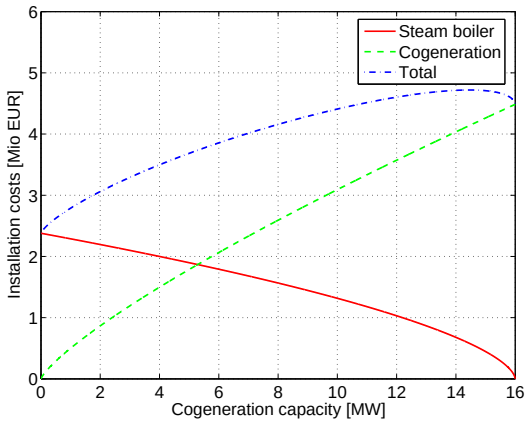


(b) Fixed O&M costs

Figure 1: Variable and fixed cost curves



(a) Specific investment costs



(b) Investment costs in absolute terms

Figure 2: Investment cost curves

optimal choice with respect to energy prices and base load duration. In order to economize the additional fixed and investment costs of CHP, the instantaneous variable costs of cogeneration must be lower than those of a steam boiler. Thus, in general, cogeneration becomes more attractive the higher electricity prices and the lower fuel prices are (i.e. the larger the so-called 'spark spread' is). Furthermore, if buy-back rates are too low, then it is not economical to deliver electricity to the grid. Figures 3 to 5 show the total cost functions and the optimal capacity choice for different levels of energy prices (p_F={15,25,35} and p_E={50,80,110} Euros per MWh, respectively) and buy-back rates (b={20,80} Euros per MWh).

Finally, the longer the cogeneration system can be operated at full capacity, the more economical cogeneration becomes. Figure 6 shows the total cost function and the optimal capacity for different levels of base load duration (t_b={4,20} hours per day).

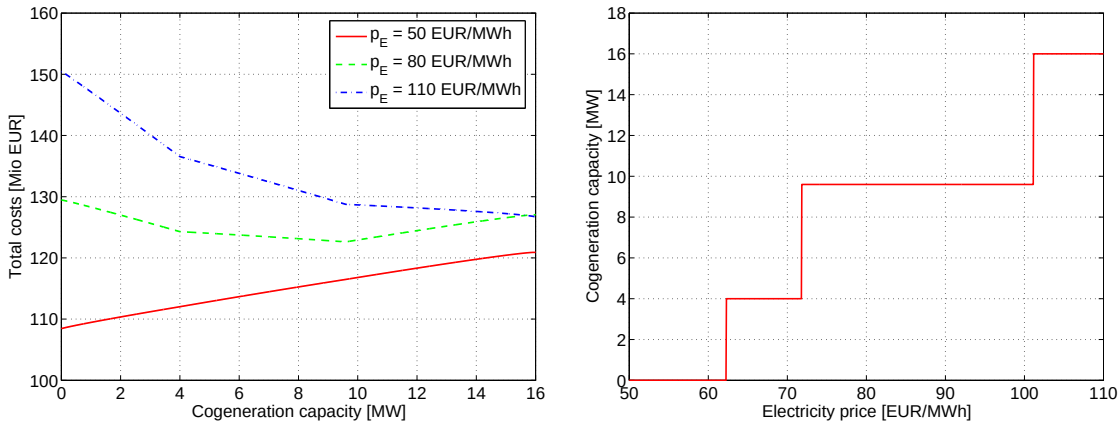
Summarizing, our sensitivity analysis shows that the optimal choice of cogeneration changes discretely. Thus, risks concerning cogeneration investments depend on the current values of key parameters, such as energy prices, buy-back rates and the characteristics of the firm's energy needs. If the parameter values are such that small changes induce a change in the optimal choice of cogeneration capacity, then the investment is risky in the sense that the firm might end up with a suboptimal mix of cogeneration and steam boiler capacity for minimizing its total energy costs.

5 Adoption and technical progress

The characteristics of technical progress are manifold. First, technical progress and learning effects lower specific investment costs. Furthermore, the technical efficiency of steam boilers and cogeneration systems improve over time.

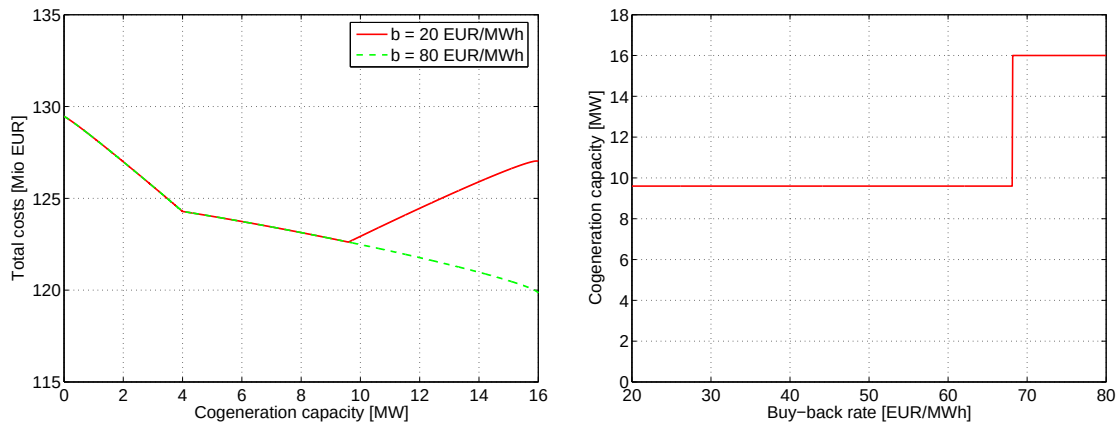
In order to analyze the optimal time of adoption and the optimal capacity choice we assume that the investor is not restricted in postponing the investment decision. We define the value of CHP adoption, V, that changes over time due to technical progress, as the difference in total costs between investing in the optimal CHP capacity and investing in a steam boiler only,

$$V(t) = F(0) - F(\tilde{L}_H^{CG}(t)), \tag{6}$$



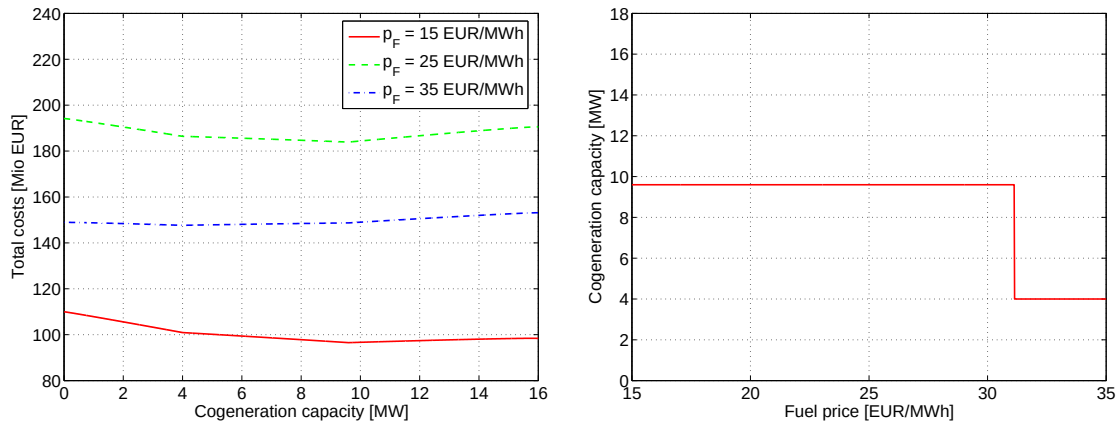
(a) Total costs (b) Optimal cogeneration capacity

Figure 3: Total cost curves and optimal CHP capacity for different electricity price levels



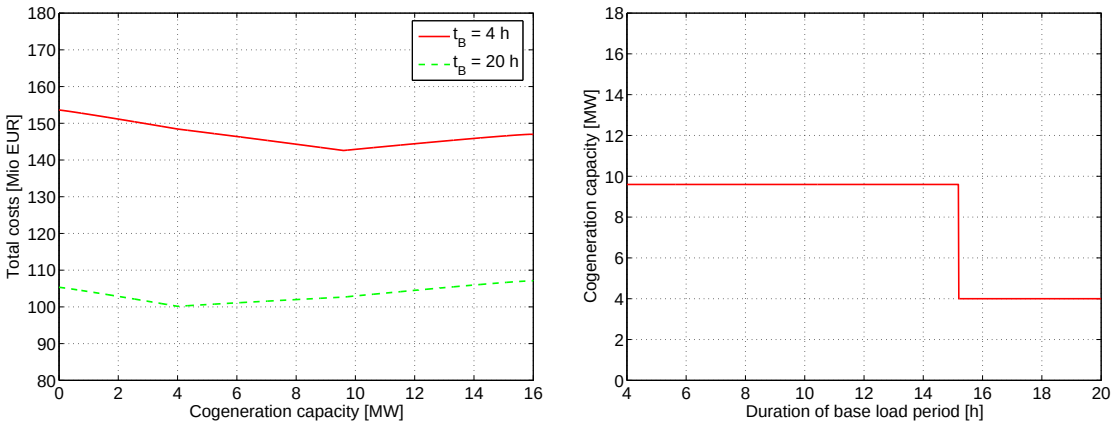
(a) Total costs (b) Optimal cogeneration capacity

Figure 4: Total cost curves and optimal CHP capacity for different buy-back rates



(a) Total costs (b) Optimal cogeneration capacity

Figure 5: Total cost curves and optimal CHP capacity for different fuel price levels



(a) Total costs

(b) Optimal cogeneration capacity

Figure 6: Total cost curves and optimal CHP capacity for different base load durations

where $\tilde{L}_H^{CG}$ is the optimal choice of cogeneration, which depends on technical progress. The net present value of adopting in time t, J, is given by

$$J[V(t)] = \mathrm{e}^{-rt}V(t) = \mathrm{e}^{-rt}\left[F(0) - F(\tilde{L}_H^{CG}(t))\right]. \tag{7}$$

Thus, the unknown optimal time of adoption, t^* (cf. Dixit and Pindyck, 1994, p.138 for a discussion within a stochastic framework), is given by the following first- and second-order conditions and the adoption condition:

$$\frac{V'(t^*)}{V(t^*)} = r, \qquad \frac{V''(t^*)}{V'(t^*)} \leq r, \qquad V(t^*) > 0 \tag{8}$$

The first-order condition for an optimum implies that the rate of change in the value to adopt, V, has to be equal to the discount rate, r. The second-order condition can be interpreted as a compound interest effect: at the optimal investment time the discount effect has to be stronger than the growth rate of the change in the value to adopt. Otherwise, it would be optimal to wait since the net present (i.e. discounted) value to adopt, $J[V(t)]$, still increases. The adoption condition is satisfied if the maximum value of adoption is positive.

In order to analyze the role of technical progress for the economics of CHP adoption we assume constant short-term energy needs (i.e. the time profile of energy demand is flat), constant energy prices and demand, and that the amount of the firm's self-generation of electricity is always lower than its electricity demand. Furthermore, we set the variable

O&M costs and fixed costs equal to zero. In this case the value of adoption can be written in terms of heat units, i.e. $v(t) = \frac{V(t)}{L_H}$, where L_H denotes (constant) heat demand,

$$v(t) = \Delta c(t) - \Delta i(t), \tag{9}$$

with

$$\begin{aligned} \Delta c(t) &= \frac{1}{r}\left[p_E s^{CG}(t) - \frac{p_F}{\eta_H^{CG}(t)}\left(\frac{\eta_H^{SB}(t) - \eta_H^{CG}(t)}{\eta_H^{SB}(t)}\right)\right], \\ \Delta i(t) &= I_s^{CG}(t) - I_s^{SB}(t). \end{aligned}$$

$\Delta c(t)$ represents the cost reduction that can be achieved per unit of heat produced with a cogeneration system, as compared to a steam boiler, whereas the first term between the brackets stands for the electricity purchases saved per unit of heat produced. The second term represents the additional fuel costs incurred for producing one unit of heat when using a cogeneration system instead of a steam boiler. Hence the cost reductions are positive if the saved electricity expenses per unit of heat produced exceed the additional fuel costs to produce one unit of heat in a cogeneration system, compared to a conventional steam boiler system. $\Delta i(t)$ indicates the heat-specific additional investment costs for cogeneration, where I_s^i denotes the heat-specific investment costs. In order to analyze the optimal time of adoption as a function of technical progress, we need to know the first derivatives of the heat-specific cost reduction function and the additional investment cost function (Eq. (9)):

$$\begin{aligned} \Delta \dot{c} &= \frac{1}{r}\left[p_E \frac{\eta_E^{CG}}{\eta_H^{CG}}\hat{\eta}_E^{CG} - \left(p_E \frac{\eta_E^{CG}}{\eta_H^{CG}} - \frac{p_F}{\eta_H^{CG}}\right)\hat{\eta}_H^{CG} - \frac{p_F}{\eta_H^{SB}}\hat{\eta}_H^{SB}\right], \\ \Delta \dot{i} &= \dot{I}_s^{CG} - \dot{I}_s^{SB}. \end{aligned}$$

Finally, according to Eq. (8) we have at the optimal time of adoption

$$r = \frac{\dot{v}(t^*)}{v(t^*)} \equiv \hat{v}(t^*), \qquad r \geq \frac{\ddot{v}(t^*)}{\dot{v}(t^*)} \equiv \hat{\dot{v}}(t^*), \qquad v(t^*) > 0. \tag{10}$$

Now we can identify the impact of technical progress on the specific value of adoption. First, an increase in the electrical efficiency raises the value of adoption, since saved electricity expenses increase. To show this consider the first order condition where only η_E^{CG} changes with time:

$$\frac{p_E s^{CG}(t^*)}{r v(t^*)}\hat{\eta}_E^{CG}(t^*) = r. \tag{11}$$

Due to the adoption condition, the denominator of the first-order condition has to be positive. The discounted value of the electricity expenses saved, $\frac{p_E s^{CG}(t^*)}{r}$, is part of the specific value of adoption, $v(t^*)$. Thus, Eq. (11) implies that at the optimal time of adoption, the rate of change in the electrical efficiency, $\hat{\eta}_E^{CG}(t^*)$, weighted by the share of saved electricity expenses in the total specific value of adoption, must equal the discount rate, r.

Next, if the thermal efficiency of the steam boiler improves (i.e. $\hat{\eta}^{SB}$ is positive), then one would expect that the value of adoption is ever decreasing. Inspection of the first-order condition

$$-\frac{\frac{p_F}{\eta_H^{SB}(t^*)}}{rv(t^*)}\hat{\eta}_H^{SB}(t^*) = r \tag{12}$$

reveals that the left-hand side of Eq. (12) is negative for positive $\hat{\eta}_H^{SB}$. Hence we can see that Eq. (12) only holds if the heat-specific value of adoption is negative, which clearly violates the adoption condition.

If only the thermal efficiency of CHP increases, then the optimal time of adoption depends on the fuel costs of CHP and the saved electricity expenses due to the operation of cogeneration:

$$\frac{\frac{p_F}{\eta_H^{CG}(t^*)} - p_E s^{CG}(t^*)}{rv(t^*)}\hat{\eta}_H^{CG}(t^*) = r. \tag{13}$$

At the optimal time of adoption, the rate of change in the thermal efficiency of the cogeneration system, $\hat{\eta}_H^{CG}(t^*)$, weighted by the share of the discounted fuel costs net of saved electricity costs, $\frac{1}{r}\left(\frac{p_F}{\eta_H^{CG}(t^*)} - p_E s^{CG}(t^*)\right)$, on the specific value of adoption, $v(t^*)$, has to be equal to the discount rate.

However, in practice both electrical and thermal efficiency of CHP change over time. Usually, technical progress in cogeneration increases total efficiency and electrical efficiency, whereas the thermal efficiency of the cogeneration system falls. In other words $\hat{\eta}_H^{CG}$ is negative. If the electrical and the thermal efficiency of the cogeneration system change, then the first-order condition becomes

$$\frac{\frac{p_F}{\eta_H^{CG}(t^*)}\hat{\eta}_H^{CG}(t^*)}{rv(t^*)}\hat{\eta}_H^{CG}(t^*) + \frac{p_E s^{CG}(t^*)}{rv(t^*)}\hat{s}^{CG}(t^*) = r, \tag{14}$$

where $\hat{s}^{CG}$ denotes the relative change in the electricity rate of the cogeneration system. As Eq. (14) for an interior solution shows, the effect of additionally saved electricity costs

per heat unit due to an increase in the electricity rate, i.e. the first term in Eq. (14), has to outweigh the effect of additional fuel costs due to the falling thermal efficiency, given by the second term in Eq. (14).

Finally, a similar analysis can also be made for decreasing investment costs. The difference in the rate of change between the specific investment costs for the steam boiler and the cogeneration technology, weighted by its share in the specific value to adopt, must equal the discount rate, i.e.

$$\frac{I_s^{SB}(t^*)}{v(t^*)}\hat{I}_s^{SB}(t^*) - \frac{I_s^{CG}(t^*)}{v(t^*)}\hat{I}_s^{CG}(t^*) = r. \tag{15}$$

The above analysis also shows the importance of expectations in the context of technology diffusion (Rosenberg, 1976; Ireland and Stoneman, 1986) with respect to changes in two important technical parameters: electrical efficiency increases and (specific) investment cost decreases. Obviously, a broader analysis would have to incorporate all economic and technical parameters and variables considered important. In the next section we perform a numerical simulation analysis considering the case of technical progress in the electrical efficiency of cogeneration, based on the cost functions derived in section 3. Moreover, in order to explicitly include uncertainty in the analysis, this would call for the development of a stochastic CHP adoption model (like the one introduced in Wickart and Madlener (2007)). In such a stochastic model it would in principle also be possible to consider unforeseen changes in heat demand caused by radical technological innovation (like, for example, the switching from thermal to biochemical processes in the chemical industry).

6 Numerical simulations

In this section we illustrate the theoretical insights gained from our adoption model with the help of a numerical example. In particular, we determine the impact of technical progress on the optimal time of adoption for the case in which only the electrical efficiency of CHP increases. Thus, we investigate the optimal time of adoption as given in Eq. (11) applying the cost model developed in section 3. To calibrate the model, we use realistic parameter values derived from unpublished Swiss cogeneration plant data from the chemical industry sector, which are summarized in Table 3. For the investment and fixed costs we used the

Table 3: Parameterization of the numerical example

Parameter	*Symbol*	*Value*	*Unit*
Base heat load	$L_{H,B}$	4	MW
Peak heat load	$L_{H,P}$	16	MW
Electricity load	L_E	4	MW
Period length	T	24	hrs
Base load period length	t_B	12	hrs
Operation time		8'760	hrs/a
Discount rate	r	5%	p.a.
Fossil fuel price	p_F	25	Euro/MWh
Electricity price	p_E	65	Euro/MWh
Buy-back rate	b	57	Euro/MWh
Thermal efficiency of steam boiler	η^{SB}	0.9	
Thermal efficiency of CHP system	η_H^{CG}	0.6	
Electrical efficiency of CHP system	η_E^{CG}	0.25	

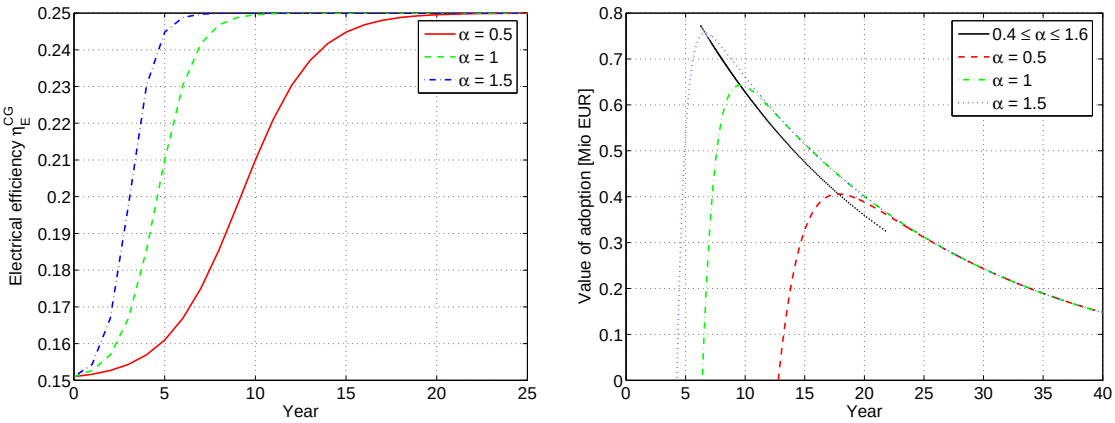
functions as shown in Figures 1(b) and 2.

We assume that the increase in electrical efficiency of the cogeneration system follows a logistic function of the form

$$\eta_E^{CG} = \underline{\eta}_E^{CG} + \frac{\overline{\eta}_E^{CG} - \underline{\eta}_E^{CG}}{1 + \mathrm{e}^{-\alpha(t-\beta)}},$$

where $\underline{\eta}_E^{CG}$ stands for the electrical efficiency of the cogeneration system, $\bar{\eta}_E^{CG}$ indicates the maximum achievable (i.e. state-of-the-art) electrical efficiency, and α and β are parameters to be determined. For the speed of technical progress, α, we choose values between 0.5 and 1.5. Parameter β is calibrated such that $\eta_E^{CG}(0) = 0.151$. Figure 7(a) depicts some sample paths, tracing the increase in electrical efficiency of the cogeneration system as a function of the optimal time to adopt, for different values of parameter α. It can be seen that the more slowly technical change progresses, the longer a potential CHP technology adopter should wait to invest.

It can be shown that with increasing speed of technical progress, α, the optimal time of adoption (i.e. the optimal duration of waiting to invest in CHP technology) decreases, while the optimal (i.e. maximum achievable) electrical efficiency increases. Note that both effects increase the optimal net present value of adoption: (1) the higher the electrical



(a) Electrical efficiency gains

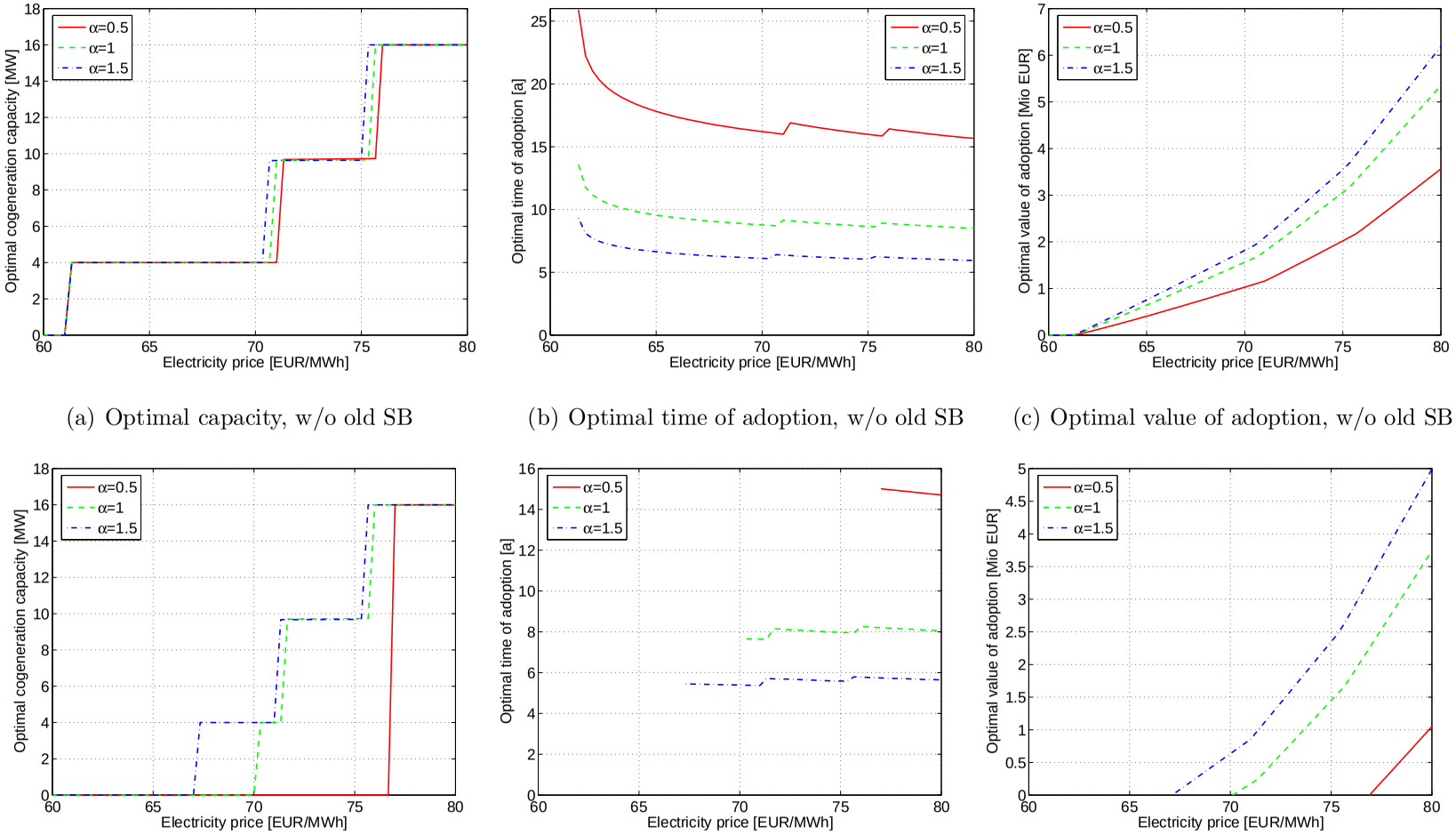
(b) Optimal NPV of adoption

Figure 7: Technical progress and its impact on the optimal net present value of adoption

efficiency, the higher is the value of adoption; (2) the shorter the optimal time of adoption, the lesser is the discounting effect.

Finally, the sensitivity of the net present value to changes in α can be seen from Figure 7(b), where we have plotted the development of the net present value for different technical progress rates (towards an optimal value NPV*) against the time of adoption, t. Linking all optimal net present values that accrue from varying α with each other creates the descending NPV curve shown in Figure 7(b).

Figures 8(a) to 8(c) show the optimal capacity choice, the optimal time and optimal value of adoption for different levels of the electricity price and technological progress if the firm is not restricted in postponing the investment decision. According to Figure 8(a), the impact of technical progress on the optimal capacity is small. However, if we take into account that the firm operates using an old steam boiler, then technological progresses affects the adoption of cogeneration and the optimal cogeneration capacity markedly (Figures 8(d) to 8(f)). The impact of technological progress on the optimal cogeneration capacity is higher for low electricity prices, i.e. if cogeneration is less attractive. Furthermore, the optimal cogeneration capacity exhibits discrete jumps as the electricity price varies. This is due to the discrete change in the optimal dispatching strategy as the electricity price changes. Note that our analysis also holds if we fixed the electricity price and varied the fuel price, since it is the spread between the electricity and the fuel price that matters for the attractiveness of cogeneration.



(a) Optimal capacity, w/o old SB

(b) Optimal time of adoption, w/o old SB

(c) Optimal value of adoption, w/o old SB

(d) Optimal capacity, with old SB

(e) Optimal time of adoption, with old SB

(f) Optimal value of adoption, with old SB

Figure 8: Optimality of selected parameters for different electricity price levels when the existing steam boiler is disregarded (plots a-c) and when it is taken into account (plots d-f)

7 Conclusions

In this paper we have discussed the decision-making problem of an industrial investor to either adopt cogeneration or heat-only generation technology. For determining the optimal time of adoption the industrial firm is assumed to be unrestricted in postponing the adoption decision. The deterministic CHP adoption model proposed is specified in continuous time and takes a lifetime perspective. We therefore distinguish between instantaneous costs for optimal operation at fixed capacity (optimal dispatching), discounted variable cost over the lifetime of the system, and optimal capacity choice/mix.

Uncertainty is included by assessing the impact of changes in energy prices and base load duration on the choice of optimal capacity and total cost. The results of our sensitivity analysis show that adoption of optimal cogeneration capacity changes in discrete steps. If small changes of the parameter values are able to trigger discrete changes in the optimal choice of cogeneration capacity, investment can be interpreted as being risky — i.e. measured by total energy costs, the firm is in danger of adopting a suboptimal heat and power generation mix.

In a numerical simulation with realistic parameter values we find that technical change affects the optimal timing of adoption. We show the importance of expectations regarding changes in key technical parameters (in our case electrical efficiency improvements over time). The higher speed of (expected) technical progress in electrical efficiency is, the higher is the value of adoption, and the shorter the optimal time until adoption, and therefore the lower is the relevance of the discounting effect. Furthermore, we show that the speed of technical progress affects the optimal CHP capacity choice over a range of alternative electricity prices in a discrete way.

Due to the existence of firm-specific discrete jumps, our analysis shows that the smaller the number of potential industrial cogeneration adopters is, the more difficult it is to design optimal CHP policy (for large numbers of potential adopters, firm-specific effects would average out). This calls for tailored policy actions at the firm level, provided this is feasible from an administrative point of view, e.g. regarding transaction costs or information asymmetries.

At the more general level, our investigation provides some interesting new insights in

situations of co-production with by-products that can either be sold in the market or used as an input in another production process of the firm. Specifically, the case is for alternative process technologies, which differ in the number of by-products produced, and where the investor is urged to choose the optimal technology mix. Finally, the model developed is designed to represent the technical peculiarities of cogeneration use in industries (time varying load profile, heat-electricity intensity) in a stylized way, but also allows for an analytical investigation of the economics of cogeneration adoption.

8 Acknowledgements

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Appendix

We show the derivation of the cost function if $\bar{L}_H^{CG} \leq L_{H,B}$. In this case the optimal policy is given by:

$$\hat{\theta}(t) = \begin{cases} \frac{\bar{L}_H^{CG}}{L_{H,B}} & \text{if} \quad t \leq t_B \\ \frac{\bar{L}_H^{CG}}{L_{H,P}} & \text{if} \quad t > t_B \end{cases}$$

Thus, the firm is never a net supplier of electricity and it has always to purchase some fraction of electricity from the grid. The instantaneous variable cost function is then given by:

$$\zeta(t) = \begin{cases} p_E[\bar{L}_E - \bar{L}_H^{CG} s^{CG}] + \bar{L}_H^{CG} c^{CG} + (L_{H,B} - \bar{L}_H^{CG}) c^{SB}, & \text{if} \quad t \leq t_B \\ p_E[\bar{L}_E - \bar{L}_H^{CG} s^{CG}] + \bar{L}_H^{CG} c^{CG} + (L_{H,P} - \bar{L}_H^{CG}) c^{SB} & \text{if} \quad t > t_B \end{cases}$$

If we define

$$\zeta_B(\bar{L}_H^{CG}) \equiv p_E \bar{L}_E + c^{SB} L_{H,B} + \bar{L}_H^{CG}(c^{CG} - c^{SB} - p_E s^{CG})$$

and

$$\zeta_P(\bar{L}_H^{CG}) \equiv p_E \bar{L}_E + c^{SB} L_{H,P} + \bar{L}_H^{CG}(c^{CG} - c^{SB} - p_E s^{CG})$$

then the discounted variable costs for a period with length T are given by:

$$\begin{aligned} \int_0^T \zeta(t)dt &= \int_0^{t_B} e^{-rt} \zeta_B(\bar{L}_H^{CG}) dt + \int_{t_B}^T e^{-rt} \zeta_P(\bar{L}_H^{CG}) dt \\ &= \frac{e^{-rt_B}(\zeta_P(\bar{L}_H^{CG}) - \zeta_B(\bar{L}_H^{CG})) + \zeta_B(\bar{L}_H^{CG}) - e^{-rT}\zeta_P(\bar{L}_H^{CG})}{r} \end{aligned}$$

Integrating the discounted variable cost function over the whole lifetime of the heat generation system yields the discounted variable costs function, i.e.

$$C(\bar{L}_H^{CG}) = \frac{e^{-rt_B}(\zeta_P(\bar{L}_H^{CG}) - \zeta_B(\bar{L}_H^{CG})) + \zeta_B(\bar{L}_H^{CG}) - e^{-rT}\zeta_P(\bar{L}_H^{CG})}{r - re^{-rT}}.$$

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