JEL: C610, D210, G130, Q520

A. A. Krasovskii, N. V. Khabarov, M. Obersteiner

IMPACTS OF THE FAIRLY PRICED REDD-BASED CO_2 OFFSET OPTIONS ON THE ELECTRICITY PRODUCERS AND CONSUMERS[1]

This paper deals with the modeling of two sectors of a regional economy: electricity and forestry. We show that CO_2 price will impact not only the profits of the CO_2 emitting electricity producer (decrease), but also the electricity prices for the consumer (increase), and, hence, some financial instruments might be implemented today in order to be prepared for the uncertain CO_2 prices in the future. We elaborate financial instrument based on the Reduced Emissions from Deforestation and Degradation (REDD+) mechanism. We model optimal behavior of forest owner and electricity producer under uncertainty and determine equilibrium fair prices of REDD-based-options.

Keywords: CO_2, REDD+, Option Pricing, Optimization, Firm Behavior, Cost Minimizing, Uncertaint

Introduction

This research is focused on developing financial instruments supporting activities within the framework of the Reducing Emissions from Deforestation and Forest Degradation Plus (REDD+) program. The basic idea of the program is that REDD+ would provide payments to jurisdictions (countries, states, or provinces) that reduce forest emissions below agreed-upon benchmark levels[2]. In a recent review [1] authors discuss the potential of REDD+ and show that there are many research needs and opportunities for analyzing REDD+ policy designs at the global, national, and subnational levels including examining land use planning and other applications for ongoing REDD+ policy processes. The economic modeling tools provided in the literature reflect various REDD+ applications, and model the impacts of REDD+ at various scales and dimensions for scenarios of future CO_2 prices. The fixed market models are site-specific and mostly estimate the benefits of REDD+ for forests [2]. The partial equilibrium models are sector specific (forest, agriculture) and focus on particular regions, e.g. [3], in long-term perspective 50–100 years. The general equilibrium models are economy-wide and nearer-term (e. g., 20 years) [4]. There are also integrated assessment models which link global economy and biophysical systems at a very long-run

[2] United Nations Framework Convention on Climate Change [UNFCCC] 2010, https://unfccc.int/.

(e.g., at least 100 years) [5]. The variety of models demonstrates the importance of the problem and necessity of developing tools which could allow implementing REDD+ in reality (REDD+ is further referred to as REDD for the sake of a simplified notation).

In our study, we investigate the problem on the firm level and consider a microeconomic setup with interaction of three players: forest owner, electricity producer, and electricity consumer. In the model, the regional electricity producer provides electricity to consumers by running its power plants which vary in the employed technology and costs. The company has market power, i.e. the ability to profitably shift prices above competitive levels by demanding a higher price than marginal cost, and sets the price for electricity according to the demand function of the consumers. The economic models of market power applied to the electricity markets are presented in part 4 of the book [6]. The reasons for market power in the electricity sector, as well as examples for several regions, are discussed in the international review of wholesale electricity markets and generator's incentives in [7]. In our study we model market power in order to link CO_2 prices with electricity prices, and, hence, CO_2 prices also impact the consumer. The electricity sector is implemented in various macroeconomic energy models which take into account the impact of CO_2 prices as well (see a recent review [8]).

An important feature of our study is the short-term analysis meaning that the electricity producer is restricted in his adaptation to uncertain CO_2 prices: the only options are to modify the production process using installed capacities, or raise electricity prices and use REDD certificates to offset emissions. This creates an incentive to buy REDD options to hedge now against uncertain CO_2 prices in the near future. We assume that the REDD mechanism supporting such activities exists [9]. On the supply side of the REDD market, we model the forest owner who decided to preserve the forest and sell respectively generated REDD offsets. Our study contributes to research on the potential of using REDD options in the energy sector (see for example [10], where the real options framework is applied). The focus of our analysis is on how forest owner and electricity producer choose their fair prices for different amounts of REDD options. The fair REDD option price in the paper is understood in the sense of parties' indifference to whether engage in contracting a given amount of REDD options or not. The fair price of electricity producer (forest owner) means that for higher (lower) price the electricity producer (forest owner) will not want to engage in the contract. The idea of fair price is natural for the option trading. For example in Chapter 2 in [11] the author writes that "fair" (in the context of fair option price) means that the expected profit for both sides of the option contract is 0. Similar idea of fair price (rational cost) of options is developed in the study, toward the theory of pricing of options [12].

The construction of fair prices in the model is based on the transparency of information concerning the emissions generated by the electricity producer under different CO_2 price scenarios and the technological process used in the production. We link decision-making of the electricity producer and the forest owner, and, hence, construct a supply-demand model for the REDD: fair prices for every amount of traded REDD options. Under assumption of perfect information, we prove the existence of the equilibrium amount of options for which the fair prices coincide.

The structure of the paper is the following. In the first part of the paper, we describe the basic model and solve it for the equilibrium electricity price in the region by cost-benefit analysis of the electricity generation in the absence of emission fee — zero CO_2 price. The analysis consists of optimizing a technological portfolio and choosing the aggregate production output in order to satisfy the hourly average demand profile, and to maximize aggregate profit. Technically, we formulate a nonlinear optimization problem and approximate it by the appropriate numerical algorithm making use of linear programming.

In the second part, we analyze the impacts of CO_2 prices on decision-making of the electricity producer who will modify technological mixes depending on the emission factors of technologies and the value of CO_2 price. We consider a short-term period in which the electricity producer does not build new power plants and does not install abatement technologies such as carbon capture and storage (CCS) modules. The producer optimizes the technology mix in the production process and sets electricity prices for the consumers. Along these lines we show the impact of growing CO_2 prices on profits of the electricity producer, electricity prices for the consumer and emission levels. Thus, rather myopic behavior of a business sector is analyzed. Nevertheless, this is a reasonable approximation of reality where investments into power generation are costly and long-term, hence very inflexible[1].

The third part of the paper is devoted to the analysis of financial instruments based on REDD+

[1] e. g. http://www.iiasa.ac.at/web/home/about/news/20140331-Coal-Johnson.html.

offsets which can be used for hedging in the electricity sector. We model negotiations of the forest owner and electricity producer who choose the size of the option and the corresponding price under CO_2 price uncertainty. The forest owner keeps the forest and is paid for it through the REDD mechanism. The electricity producer is interested in buying REDD certificates to offset his emissions in the future when CO_2 prices are introduced. Thus, it is assumed that through the REDD mechanism the electricity producer can transparently choose the amount of certificates they want to trade today. For simplicity we do not consider transfer costs and reduce the problem to two groups, assuming that on the market they are the same on both sides. The problem is divided into two stages: at the first stage they fix an amount of options and the price, in the second they optimally use REDD options in the presence of uncertain CO_2 prices. The above formulation can be applied to a two-stage stochastic programming problem with recourse, pioneered by Dantzig [13]. We provide an analysis of several instruments based on REDD offsets, and construct supply and demand curves for REDD. In the calculation of the expected payoffs needed for determining the fair prices, we assume that the forest owner knows that the electricity producer will maximize the expected profits with REDD options and can solve the same problem in order to calculate his expected payoff. As the fair price is defined based on expected profit value only and does not take into account e.g. a distribution tail, we implicitly assume that both electricity producer and forest owner are risk-neutral. We also do not include additional factors to the utility of the forest owner such as opportunity costs of the forest, etc., so that his payoff is only the income from REDD offsets. In this modeling framework we show that in the case when electricity producer and forest owner possess equal information about the CO_2 price distribution, the equilibrium quantity of REDD options exists and equals the minimum amount of emissions corresponding to the maximum CO_2 price in the given interval of the bounded discrete distribution. We show that larger amounts of options provide an increase in emissions, as well as decrease in the electricity prices, but in this case the fair price of the forest owner is higher than the price of electricity producer calling for the necessity of exogenous financial support to obtain those benefits for both electricity producer and consumer. Throughout the paper, we provide numerical results applied to the case study for the model of a region based on realistic data.

1. Model Setup

The model analyzes the decision-making of an electricity producer under constraints on the available technological capacities and the electricity demand of the consumers. The electricity producer has perfect information concerning the costs of his production technologies and the consumers' demand function. We consider the short-term period when the capacity for each technology is fixed, i.e. the electricity producer operates his power plants and does not change their installed capacities. Variable costs of the electricity production are constant as we do not focus on feedbacks between electricity and fuel prices, i.e. spark spreads [14].

The decision-making of the electricity producer consists of the following steps:

1. Choosing the load factors of his power plants in a way which minimizes the costs given an hourly electricity demand profile and installed technological capacities (lookup table).
2. Choosing an electricity price to maximize the profit based on the demand function indicating consumer's sensitivity to electricity prices.
3. Modeling with CO_2 prices.
4. Modeling with buying options on REDD offsets.

In this section, we sequentially formulate and solve two optimization problems arising in the steps 1-2. Throughout the paper, we provide numerical results for a case-study in order to illustrate the model. The case-study does not describe a real region of the world, but simulates an artificial region having realistic features in the framework of the model assumptions.

1.1. Optimal Mix of Technologies

A simple model of a power plant categorizes all costs into two components: fixed costs and variable costs [15]. Fixed costs include capital costs, taxes, insurance, and any fixed operations and maintenance costs that will be incurred even when the plant is not operated. Variable costs are the added costs associated with running the plant including fuel plus operations and maintenance costs. Technically, it means that the cost function for each technology in the model is linear with respect to the amount of generated electricity.

The technologies used by the regional electricity producer and their costs are taken from the book [15]. We choose technologies based on coal and gas (which generate CO_2 emissions) in order to provide an incentive for the producer to hedge against uncertain CO_2 prices [16]. In our example the regional electricity producer has power plants with the following technologies: coal (pulverized coal steam), combustion turbine (natural-gas–

Table 1

Technological data for the case-study, based on [15, 24]

Index of technology, i	Technology	Annual fixed cost, thousands USD / MWy	Variable cost, USD per MWh	Installed Capacity, In MW	Emission factors, tons CO_2/MWh
1	Coal-fired steam cycle	224	18.9	3800	1.02
2	Natural gas-fired combustion turbine	64	55.6	1900	0.3
3	Natural-gas–fired combined cycle	96	39	2200	0.514

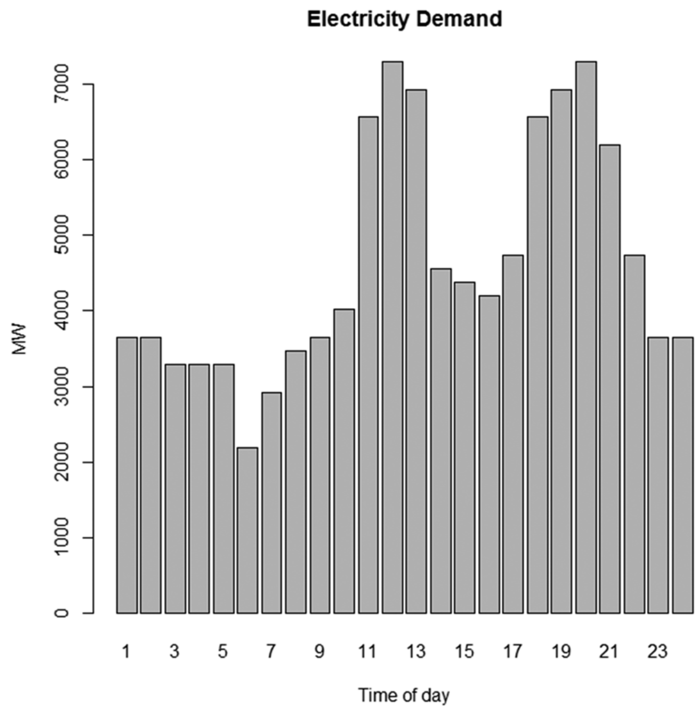

Fig. 1. *Hourly average demand profile*

fired) and combined cycle (CCGT). The corresponding fixed and variable costs, as well as the installed capacities, (in MW) for the case-study are presented in Table 1. The total installed capacity is the maximum of electricity that the electricity producer can generate using his power plants with given technologies. The size of installed capacities is chosen to illustrate a model at a regional scale.

To construct an economically efficient production plan the electricity producer has to decide what combination of technologies to use during the day in order to satisfy the hourly demand profile. A demand profile for an average day of the year is depicted on Fig. 1 and illustrates the electricity consumption during each hour of the day. It is chosen to be consistent with the regional profiles provided in the literature [17–19]. The values are consistent with the installed capacities of the electricity producer. The hourly demand usually has peaks during the average day, which lead to a problem of choosing a rational combination of technologies in the production process. To simplify the case-study we take the hourly average demand as a fixed time slice and keep it the same for each day of the longer period, e.g. one year. This simplification allows us to link the hourly profile with aggregate demand, and to assume that the change in aggregate demand leads to the proportional shifts in every hour of the profile for an average day. This assumption seems to be a reasonable simplification in the short-term dynamics of the electricity production considered in the paper.

Let us denote the installed capacities by a_i, $i = 1, \ldots, N,$ where is the index of the technology, is the number of technologies, by the corresponding variable costs, and by d_j, $j = 1, \ldots, T,$ where index stands for the hour of the day, $T = 24$, the hourly demand profile. The fixed costs cannot be changed and we aggregate them in one variable summarizing all technologies denoted by TFC. Total fixed cost is used to calculate profits. The first optimization problem for the electricity producer is formulated as follows.

Problem 1a. Find hourly capacity factors x_{ij} satisfying the daily demand d_j with minimum production cost:

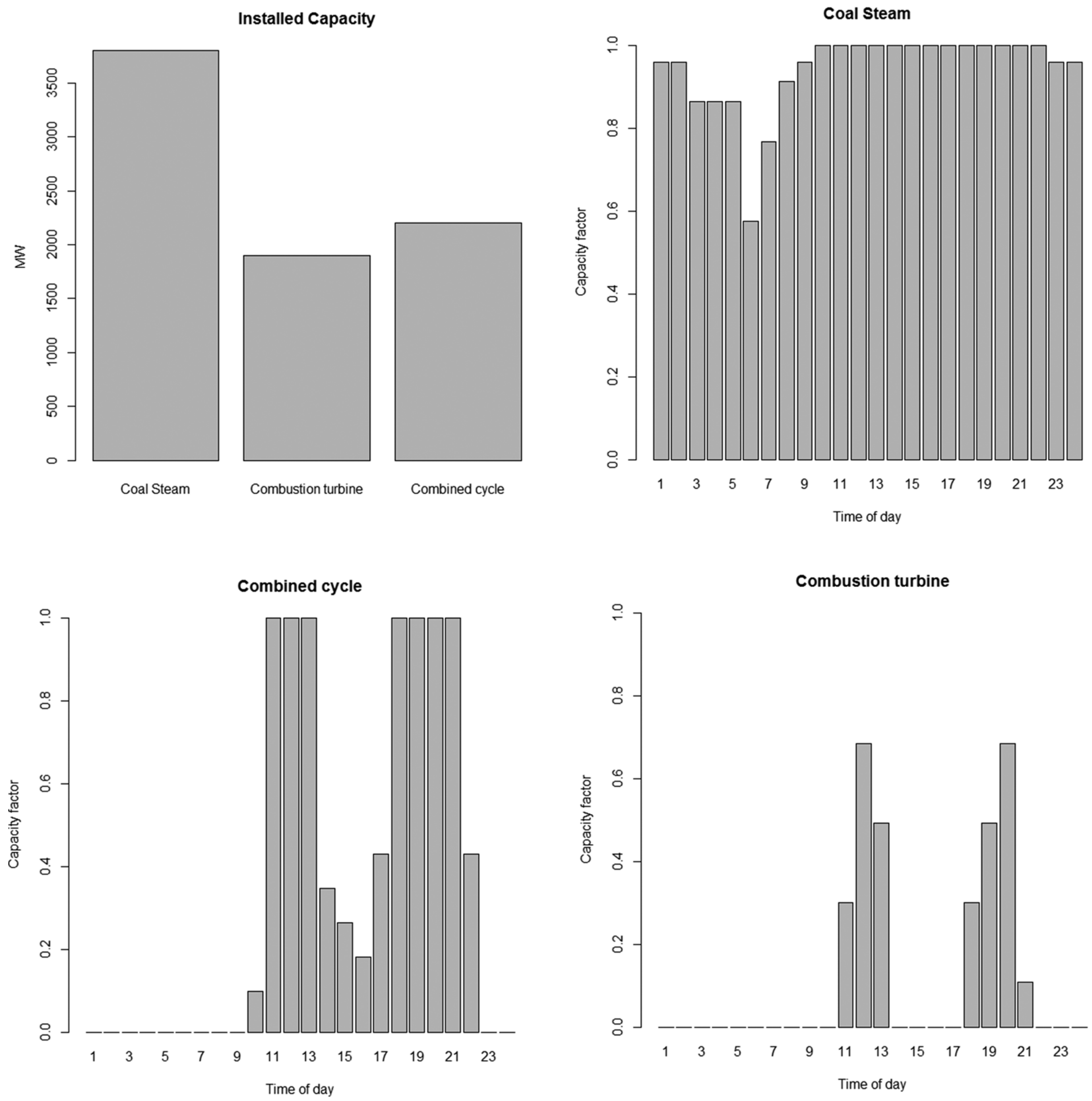

Fig. 2. *Optimal capacity factors in the absence of CO_2 price*

$$\sum_{i=1}^{N} v_i a_i \sum_{j=1}^{T} x_{ij} \underset{x_{ij}}{\rightarrow} \min, \qquad (1)$$

subject to constraints:

$$\sum_{i=1}^{N} a_i x_{ij} \geq d_j,\ 0 \leq x_{ij} \leq 1. \qquad (2)$$

Hourly capacity factors are the control variables in this problem. The solution to this linear programming problem for our case-study, $N = 3$, is presented on Fig. 2. The plots indicate hourly capacity factors for each technology on an average day. Coal-fired plants are expensive to build, but relatively cheap to operate, so they should be run more or less continuously as base load plants. Single-cycle gas turbines are relatively inexpensive to build but expensive to operate. They are mostly used at peaking power plants, turned on only during periods of high demand. Combined cycle turbine has characteristics in between, and is used to cover the intermediate load.

Our model provides a higher level of abstraction than the unit commitment (UC) problem –an optimization problem used to determine the operation schedule of the generating units at every hour interval with varying loads under different constraints and environments [20]. Namely, we do not take into account such details as start-up and shut-down costs for individual units of the generator and additional constraints which lead to mixed-integer linear programming formulations. Also we simplify the model to the static case where the average daily demand is considered (not focusing on day-to-day market fluctuations).

1.2. Market Power of the Electricity Producer

We assume that the electricity producer has market power in the region. There is evidence of regional market power in the electricity sector discussed in papers [7, 21]. This means that the electricity producer has the possibility of setting a price for electricity above their marginal cost [6]. In the model, the consumers respond to the change in electricity prices according to an aggregate demand function:

$$Q = D(P^e) \tag{3}$$

here P^e denotes the electricity price, Q stands for aggregate electricity consumption, $D(P)$ is the demand function.

Further, we assume that the hourly average demand profile is proportional to the aggregate demand, i.e. when the aggregate demand shifts from Q to Q^*, the demand profile shifts accordingly for each hour:

$$d_j^* = \frac{d_j Q^*}{Q}, Q = Y_d \sum_{j=1}^{24} d_j, Q^* = Y_d \sum_{j=1}^{24} d_j^*, \tag{4}$$

where Y_d stands for the number of days in the aggregation interval, e.g. one year. As we take it as an average profile we put $Y_d = 1$ in the formulation of the optimization problems below. In order to find the optimal solution to the profit maximization problem, a monopolist first has to calculate his cost function, which is the minimum cost of producing every feasible output Q. The cost function $C(Q)$ is generated by optimal mixes of technologies (solution to (1)-(2)) for the hourly average profile (time slice) d_j corresponding to aggregate outputs Q (4). Given the cost function $C(Q)$ the electricity producer with market power solves the second optimization problem.

Problem 1b. Choose the optimal aggregate output and set corresponding price to maximize the profit:

$$\pi(Q) = QD^{-1}(Q) - C(Q) \underset{Q}{\rightarrow} \max, \tag{5}$$

D^{-1} denotes the inverse demand function.

The demand function in the form of:

$$P^e = D^{-1}(Q) = AQ^{\alpha}, \tag{6}$$

where A — positive constant, α — elasticity of demand, is used in the model. Thus, to calibrate the aggregate demand we apply the log-linear model that is most commonly employed in aggregate energy demand studies [22], i.e. we use a constant elasticity demand curve. According to Bohi [22] there is no obvious evidence that the more complex forms of demand are superior. The log-linear specifications are preferred in the literature, because they can be adapted to sufficiently well reflect the demand and are implemented in a wide range of models. The coefficients of the aggregate demand function in our model are calibrated in such a way that a realistic electricity price of Europe[1] is achieved in the solution to an optimization problem (5). For this purpose, one can apply the necessary condition for profit maximization: marginal cost equals marginal revenue [23]. On Fig. 3 the computed approximation of the marginal cost function for our case-study is presented, whose step-wise shape is generated by optimal technological mixes.

The parameters of the demand function (6), calibrated to achieve $P^e = 90.5$ USD/M. What profit's maximum are estimated on the following levels: $A = 104.8 \times 10^3$, $\alpha = -0.612$. The value of elasticity coefficient, $|\alpha| < 1$, indicates that the demand function is inelastic. The plot of the profit function is presented in Fig. 4 and shows that it is a concave function with one maximum. Let us denote by Q_0 the profit maximizing quantity and by d_j^0 the corresponding hourly profile. These values will provide the basis for the model development below and serve for comparison of outcomes. In our example the profit maximizing quantity is $Q_0 = 100.47$ GWh, and the corresponding profit is $\pi(Q_0) = 3.56$ mln USD. Further, we will show how the electricity producer adjusts his technological mixes and sets the electricity price with respect to CO_2 prices, and compare the outcomes for different CO_2 prices. For this purpose, in the following section we provide the formal profit-maximization problem, and later approximate it by two step optimization algorithm similar to what we did in this section by solving sequentially Problems 1a-1b.

2. Modeling with CO_2 Prices

In this section we show how the optimal technology mix and electricity price will change in the presence of CO_2 prices. In this paper we assume that the electricity producer is emitting CO_2 and only consider such producers, i.e. the modeling described here is not applicable to those who have only carbon neutral technologies, e.g. hydropower or nuclear. The electricity production process provides an externality in terms of CO_2 emissions generated by fuels used in the production. The emission factors used to calculate tons of CO_2 equivalent per MWh of electricity production by each technology are based on [24]. Obviously, there is a range of values for each technology. For presently operating, coal-fired power plants the cumulative

[1] See Quarterly Reports On European Electricity Markets http://ec.europa.eu/energy/observatory/electricity/electricity_en.htm.

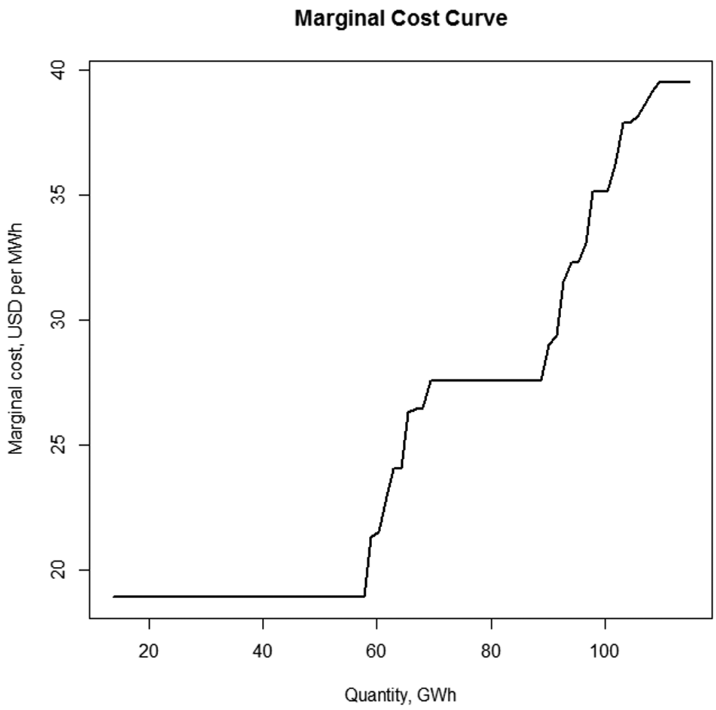

Fig. 3. *Marginal cost curve of the electricity producer as approximated by model runs and generated by optimal technological mixes satisfying the hourly demand*

emissions range between 950 and 1250 gCO_2 eq/kWh. The emissions from gas-fired power plants according to the literature range from 360 and 575 gCO_2 eq/kWh. In our study we take values from indicated intervals given in Table 1.

The impact of CO_2 prices on the electricity generation can be estimated by an increase in the variable cost of each technology. Additional variable costs increase the cost of the aggregate production and impact the profits. Thus, the electricity producer will modify his strategy, to find an optimal response to any CO_2 price. As the electricity producer will also try to compensate loses by increasing electricity prices, the consumers will react by reducing the consumption according to their demand function. Let us denote emissions factors by ϵ_i and CO_2 price by the symbol p^c. In Table 2 we present variables and notations for the model with CO_2 prices. For every CO_2 price one can formulate the following optimization problem.

Problem 2. Maximize the profit by choosing technological mix x_{ij}:

$$\sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij} \times D^{-1}\left(\sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij}\right) - \\ -\sum_{i=1}^{N} (v_i + p^c \epsilon_i) a_i \sum_{j=1}^{24} x_{ij} \underset{x_{ij}}{\rightarrow} \max, \quad (7)$$

subject to constraints:

$$\sum_{i=1}^{N} a_i x_{ij} \geq \frac{d_j^0 Q(x_{ij})}{Q^0}, \; 0 \leq x_{ij} \leq 1. \quad (8)$$

Here Q^0 is the optimal aggregate production in the absence of CO_2 price, and d_j^0 is corresponding hourly profile (solution to Problems 1a-1b), i.e. they are solutions to Problem 2 when $p^c = 0$. In this way we guarantee the consistency between Problems 1a-1b and 2.

Problem 2 is nonlinear due to the possibility of varying the production output in the inverse demand function $D^{-1}(Q(x_{ij}))$ (6). In the next section a description of the numerical algorithm is provided. The algorithm allows us to solve numerically optimization problems arising further in the paper using the linear programming technique.

2.1. The Profit Maximization Algorithm

Let the feasible aggregate production outputs be given by K discrete value $Q_k, k = 1,..,K$. The profit maximization problem for any fixed CO_2 price p^c is solved in following steps:

1. Find the optimal mix of technologies and corresponding cost $C_k = C(Q_k)$;
2. Calculate electricity prices $P_k^e = D^{-1}(Q_k)$ and corresponding revenues $R_k = Q_k P_k^e$;
3. Calculate profits $\pi_k = R_k - C_k$;
4. Find maximum profit $\hat{\pi} = \max_k \pi_k$, and hence corresponding quantity $\hat{Q}$, emissions $\hat{E}$ and electricity price $\hat{P}^e$.

The algorithm is implemented in R, the software environment for statistical computing and graphics[1], using the "linprog" package[2]. In Fig. 5

[1] http://www.r-project.org/

[2] http://linprog.r-forge.r-project.org/

Table 2

Formulas used in the model

Notation	Variable, units
$E = \sum_{i=1}^{N} \epsilon_i a_i \sum_{j=1}^{24} x_{ij}$	Emissions, tons CO_2
$V = \sum_{i=1}^{N} (v_i + p^c \epsilon_i) a_i \sum_{j=1}^{24} x_{ij}$	Variable cost in the presence of CO_2 price
$Q = \sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij}$	Quantity producedMWh
$R = Q \times D(Q) = \sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij} \times D^{-1}\left(\sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij} \right)$	Revenue, USD
$C(Q) = FC + V(Q)$	Cost function, USD
$\pi_0(Q) = \sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij} \times D^{-1}\left(\sum_{i=1}^{N} a_i \sum_{j=1}^{24} x_{ij} \right) - \sum_{i=1}^{N} v_i a_i \sum_{j=1}^{24} x_{ij} - FC$	Profit without emission fee, USD
$\pi(Q) = R(Q) - C(Q) = \pi_0(Q) - p^c E(Q)$	Profit function, USD

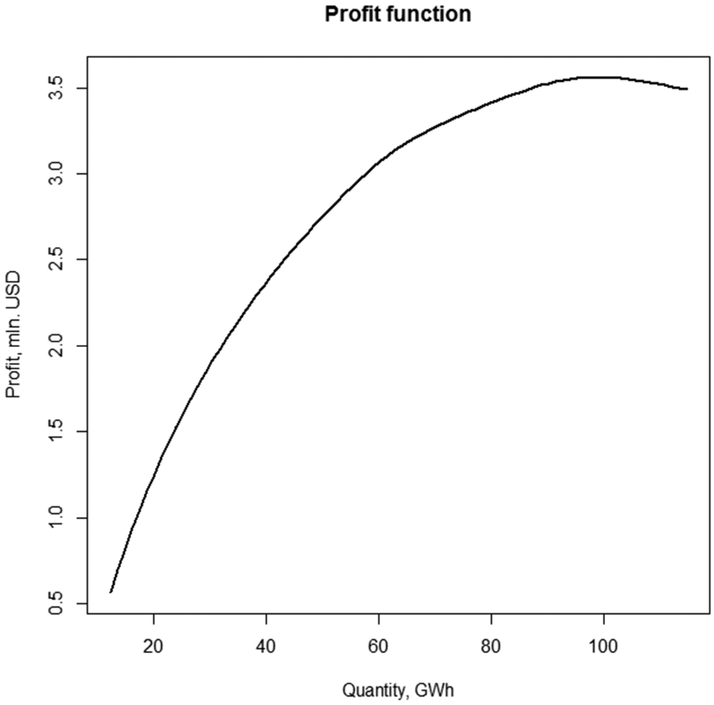

Fig. 4. *Profit function in the model*

one can see how the optimal technological mixes change with the increase of the CO_2 price. The technologies are switching as their variable costs increase with higher CO_2 prices.

For every price p^c, we find the maximum profit $\hat{\pi}(p^c)$ and corresponding optimal emissions $\hat{E}(p^c)$. Results of modeling are given on Fig. 6 for nine discrete values of CO_2 prices from 0 to 80 USD per ton CO_2. Obviously, the highest profit $\hat{\pi}(0) = \hat{\pi}(p^c = 0) = 3.56$ mln USD and emissions level $\hat{E}(0) = 93$ Mt CO_2 are achieved in the absence of CO_2 price. These values as well as production output decrease with respect to growing CO_2 prices. One can see that the electricity producer will transfer some of his loses from the CO_2 prices on customers — electricity price is growing from $\hat{P}^e(0) = 90.5$ USD/MWh to $\hat{P}^e(80) = 204$ USD/MWh. The minimum profit, production and emission levels are achieved at the maximum CO_2 price in the interval: $\hat{\pi}(80) = 0.07$ mln USD, $\hat{Q}(80) = 26.66$ GWh and $\hat{E}(80) = 8$ Mt CO_2.The nonlinearities of the optimal functions with respect to CO_2 prices

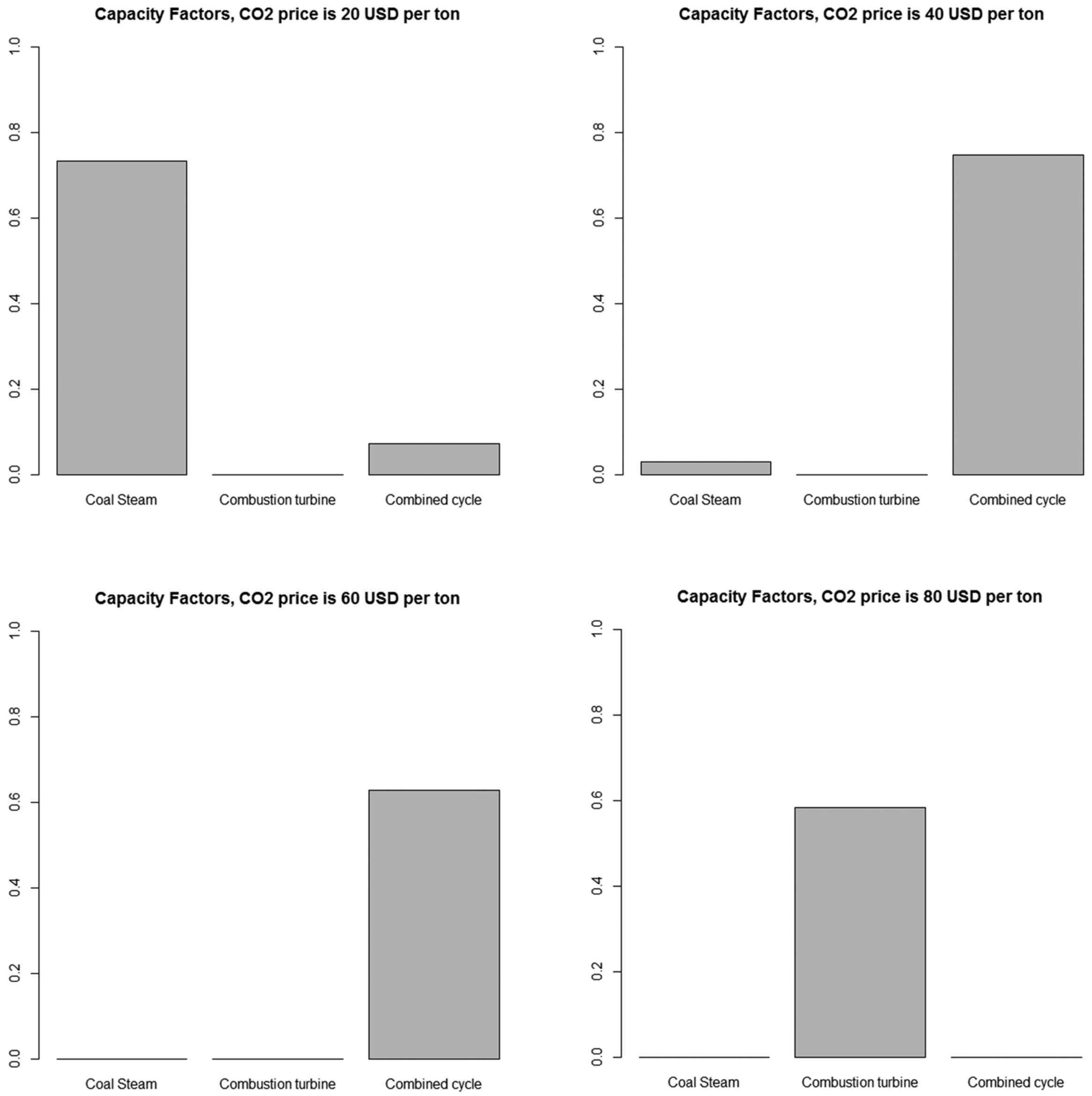

Fig. 5. *Technology mixes with respect to CO_2 price*

are explained by the possibilities of switching between technologies which results in a nonlinear shape of the marginal cost function which is constructed for each CO_2 price.

3. Instruments Supporting REDD

In this section, we model the fair prices of REDD options chosen by the forest owner and electricity producer. The fair REDD option price in the paper is understood in the sense of parties' indifference to whether engage in contracting a given amount of REDD options or not. Such notion of fair or rational price is similar to the one used in the theory of options trading [11, 12]. We assume that in the case of CO_2 prices appearing in the future the electricity producer may let the REDD offsets option contracts with forest owner. These REDD offsets are accepted in and, hence, are part of a bigger CO_2 market influenced by other players — on the demand (emitters) side — industries including steel, transportation, construction — and on the supply side — policymakers providing emission permits. In this wider market, those emitters who are able to efficiently reduce their emissions might sell some of their permits on the market. The simplifying assumption we make is that the REDD options contracts do not impact the «bigger» market, or their potential impact is included in the uncertain future CO_2 price.

3.1. Modeling of REDD Options under Uncertainty

In our model, the electricity producer and forest owner are both risk neutral — they do not have any risk preferences in terms of their utility functions, and thus we deal only with expected payoffs for each player. The future values of CO_2 prices are uncertain, and for the simplified modeling we assume that the CO_2 price at the second stage is a random variable with the discrete distribution $\{p_l^c, w_i\}, l = 1, \dots, M, \sum_{l=1}^{M} w_l = 1,$ where $w_l \in [0,1]$ stands for the probability of the CO_2 price p_l^c.

The interaction between the electricity producer and forest owner is split into two stages:

1) at the first stage the forest owner and electricity producer choose for any amount E^0 of REDD options the price of these options under CO_2 price uncertainty;

2) at the second stage they face a realization p^c of previously unknown CO_2 market price and calculate their payoffs. The electricity producer can optimize their production and use the amount of options, they bought in the first period, to offset what they will emit, the rest must be returned to the forest owner at the negotiated price $p^\delta = \delta p^c, 0 \le \delta \le 1,$ which is the discounted market price.

In fact, electricity producer and forest owner get shares of the market price i.e. δ and (1 – δ) respectively, so that:

— If δ = 1, the electricity producer has a right to sell the option in the second period at the market price.

— If δ = 0, the electricity producer can only use REDD credits to offset the factual amount of their emissions and the unused credits are returned(without compensation) back to the forest owner i.e. no resale by electricity producer is possible on the market (as $p^\delta = 0$).

— If 0 < δ < 1 the electricity producer faces a trade-off between emitting more and hence using more of the contracted REDD options for offsetting their emissions versus sharing the profit with the forest owner from selling the offsets at the market price.

By definition, for any amount E^0 of REDD options, the corresponding fair price of the electricity producer (or forest owner) should provide the same expected profit for electricity producer (or forest owner) as it would be without engaging into the REDD options contract, i.e. if forest owner were selling offsets on the market and if electricity producer were buying offsets on the market.

The modeled financial instrument has common traits with both traditional options and forwards, but is distinctive. It is an «option» in the sense that an emitter has the right (but not obligation) to use any amount of offsets not exceeding the contracted volume. It is a «forward» in the sense that there is no payment required upfront (only in the future) — so no price for the «option» as such. It has also the benefit sharing mechanism for not consumed offsets between the buyer and the seller, which does not directly relate to «option» nor «forward».

The existence of REDD options at the second stage of the model leads to modifications in the optimization of production costs (see the original formula in Table 2). Namely, the variable cost function changes in the following way:

$$V_R = \sum_{i=1}^{N} v_i a_i \sum_{j=1}^{24} x_{ij} + p^c \left[\sum_{i=1}^{N} \varepsilon_i a_j \sum_{j=1}^{24} x_{ij} - E^0 \right]_+ - \delta p^c \left[E^0 - \sum_{i=1}^{N} \varepsilon_i a_j \sum_{j=1}^{24} x_{ij} \right]_+ \xrightarrow[x_{ij}]{} \min, \quad (9)$$

where $[x]_+ = \max\{x, 0\},$ meaning that the electricity producer can offset their emissions up to the amount E^0 by using REDD+ options, and the rest is sold to the forest owner at the price p^δ.

Hence, decision-making with REDD options consists in choosing between two alternative cost-minimization problems.

Problem 3.1. Minimize cost when emissions are higher than option E^0:

$$V_1 = \sum_{i=1}^{N} v_i a_i \sum_{j=1}^{24} x_{ij} + p^c \left(\sum_{i=1}^{N} \varepsilon_i a_j \sum_{j=1}^{24} x_{ij} - E^0 \right) = \sum_{i=1}^{N} \left(v_i + p^c \varepsilon_i \right) a_i \sum_{j=1}^{24} x_{ij} - p^c E^0 \xrightarrow[x_{ij}]{} \min, \quad (10)$$

subject to constraints:

$$\sum_{i=1}^{N} a_i x_{ij} \ge \frac{d_j^0 Q(x_{ij})}{Q^0}, \; 0 \le x_{ij} \le 1, \quad (11)$$

$$\sum_{i=1}^{N} \varepsilon_i a_i \sum_{j=1}^{24} x_{ij} \ge E^0. \quad (12)$$

Problem 3.2. Minimize cost when emissions are less than option E^0:

$$V_2 = \sum_{i=1}^{N} v_i a_i \sum_{j=1}^{24} x_{ij} - \delta p^c \left(E^0 - \sum_{i=1}^{N} \varepsilon_i a_j \sum_{j=1}^{24} x_{ij} \right) = \sum_{i=1}^{N} \left(v_i + \delta p^c \varepsilon_i \right) a_i \sum_{j=1}^{24} x_{ij} - \delta p^c E^0 \xrightarrow[x_{ij}]{} \min, \quad (13)$$

subject to constraints:

$$\sum_{i=1}^{N} a_i x_{ij} \ge \frac{d_j^0 Q(x_{ij})}{Q^0}, \; 0 \le x_{ij} \le 1, \quad (14)$$

$$\sum_{i=1}^{N} \varepsilon_i a_i \sum_{j=1}^{24} x_{ij} < E^0. \quad (15)$$

Problems 3.1–3.2 present two option sat the second stage: to emit more than E^0 (the amount contracted via REDD options at the first stage) and then pay the market price for the excess of emissions, or to emit less than E^0 and receive the discounted price for the saved emissions. In the first case the forest owner does not receive any part of the REDD offsets back, in the second case the forest owner receives a part of the offsets and resells them at the market price. In other words, the electricity producer and forest owner share the income from unused options and their shares are determined by parameter δ.

For any fixed value of E^0, the Problem 3.1 always has a feasible solution, while problem 3.2 could be unsolvable for some values E^0 due to conflicting constraints on minimum production (14) and maximum emission (15). In this case solution to Problem 3.1 is taken as the cost-minimizing solution. In the case when both problems have feasible solutions we choose the solution providing minimum cost:

$$V^0 = \min\{V_1, V_2\}, \qquad (16)$$

by choosing between V_1 (10) and V_2 (13), and take the corresponding control variable (technological mix) as the optimal at the second stage.

After constructing the modified costs V^0 at the second stage for a fixed value of E^0, the electricity producer solves profit-maximizing problem following steps 2-5 in the algorithm described in section 2.1.

3.2. The Fair Prices of REDD Options

In this section, we provide a formal definition of the fair prices of REDD options which are determined by the expected payoffs of the electricity producer and forest owner. We assume that they both have perfect information about the technological capacities and costs, i.e. the forest owner knows that the electricity producer will solve the optimization problem discussed in the previous section and possesses the data to solve the same problem. Given that the electricity producer and forest owner face the same distribution of the CO_2 price at the second stage, they solve the same optimization problem, but with different focuses. While the electricity producer is interested in the expected profit, the payoff of the forest owner is based on the expected emissions returned by the electricity producer at the second stage. Let us note that we are not taking into account additional factors in the payoff of the forest owner, e.g. opportunity costs from the cutting and selling the forest, etc. It could be the case that those costs are not comparable with the benefits from REDD or the forest owner decided to keep the forest exclusively for the REDD offsets. The described framework allows us to construct the demand and supply curves for REDD options: fair prices for each amount of options, and find the equilibrium quantity where the curves intersect.

Table 3

List of expected values in the model of fair prices

Notation	Variable
$\bar{\pi} = \sum_{l=1}^{M} \hat{\pi}\left(p_l^c\right) w_l$	expected profit without REDD options
$\bar{\pi}_R = \sum_{l=1}^{M} \hat{\pi}_R\left(p_l^c\right) w_l$	expected profit with REDD options
$\bar{E}_t = \sum_{l=1}^{M} \hat{E}_t\left(p_l^c\right) w_l$	Expected amount of emissions returned to the forest owner
$\bar{p}^c = \sum_{i=1}^{M} p_l^c w_l$	Expected market price

For each CO_2 price p_i^c appearing at the second stage we introduce the following notations. We denote by $\hat{\pi}\left(p_l^c\right)$ the maximized profit without REDD ($E^0 = 0$) calculated as the solution to Problem 2. Let us denote by the symbol $\hat{\pi}_R\left(p_l^c\right)$ the maximized profit with REDD, and by the symbol $\hat{E}_t\left(p_l^c\right) = \left[E^0 - \hat{E}_R\left(x\right)\right]_+$ the corresponding optimal amount of emissions returned to the forest owner (solution to (9)). These values are calculated according to the algorithm described in the Section 2.1 with modifications in step 1 which should take into account the procedure of cost minimization with REDD options (16). In the Table 3 one can find formulas for the corresponding expected values which are used in the model with uncertainty.

The electricity producer wants his expected profit to stay the same no matter if he buys options or not. Denoting his desirable price by the symbol p_G, one gets the following equation:

$$\bar{\pi} = \bar{\pi}_R - p_G E^0. \qquad (17)$$

The forest owner has two alternatives:

1. do nothing in the first period and sell the amount E^0 in the second period at theexpected market price $\bar{p}^c$;

2. sell the amount E^0 at price p_F in the first period, buy the expected amount $\bar{E}_t$ at price δp^c and resell it at the market price in the second period.

Based on the desired equivalence of those two alternatives, the fair price for the forest owner p_F is determined by the equation:

$$E^0 \bar{p}^c = \bar{E}_t\left(\bar{p}^c - \delta \bar{p}^c\right) + p_F E^0. \qquad (18)$$

Based on the equations (17)–(18) one can formulate the definition for fair prices.

Definition. For a given discount $\delta, 0 \le \delta \le 1$, andamount of options E^0 the fair prices for the electricity producer p_G and forest owner p_F are calculated as follows:

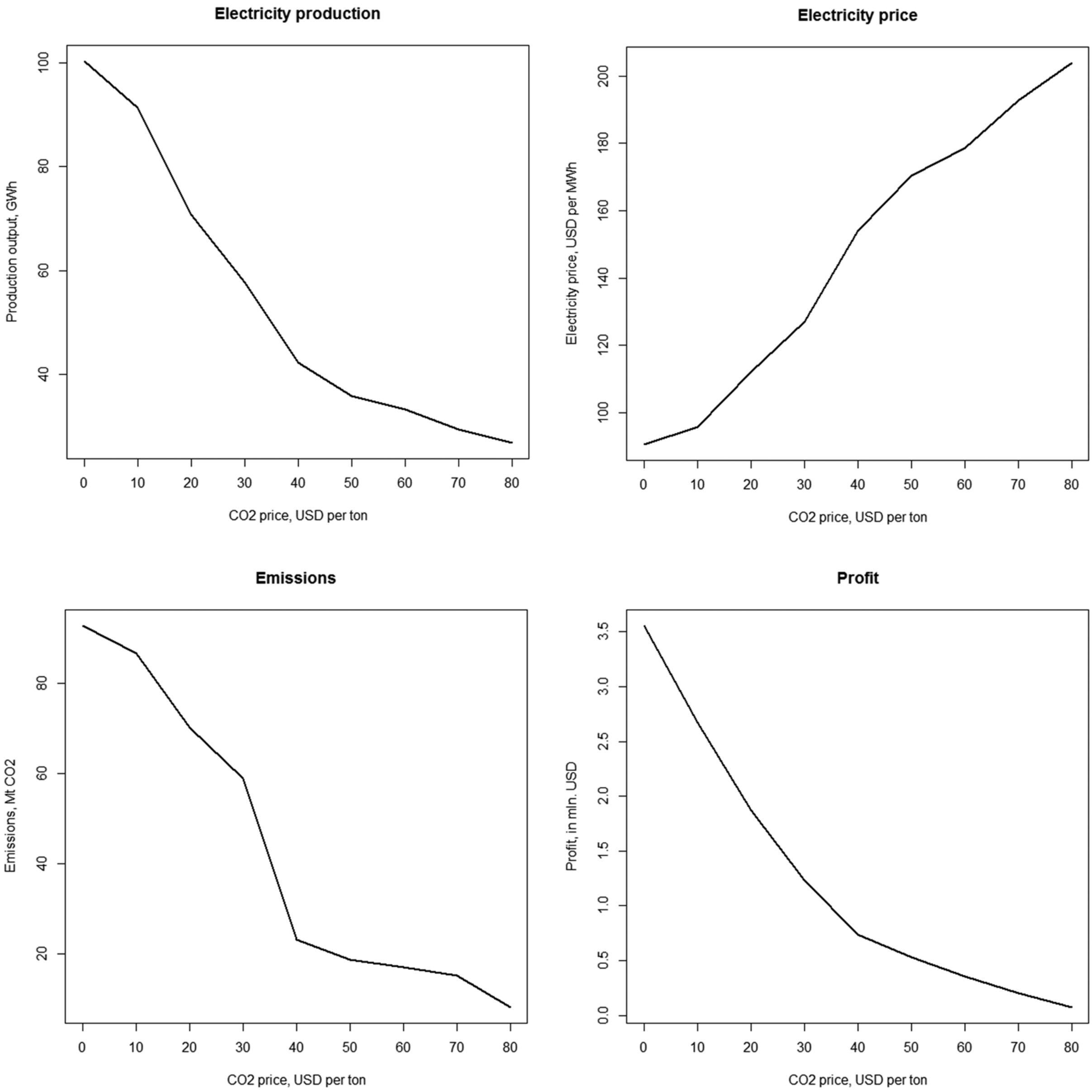

Fig. 6. *Optimal electricity production, electricity price, emissions, and profits with respect to CO_2 price*

$$p_G\left(E^0,\delta\right)=\frac{\overline{\pi}_R\left(E^0,\delta\right)-\pi}{E^0}, \tag{19}$$

$$p_F\left(E^0,\delta\right)=\overline{p}^c\left(1-\left(1-\delta\right)\frac{\overline{E}_t\left(E^0,\delta\right)}{E^0}\right). \tag{20}$$

One can see that fair prices are calculated differently: the electricity producer is interested in its expected profits while the forest owner takes care of the emissions expected to be returned back to them in the second period (as they determine their profits). An important parameter in the formulas is the amount of contracted options E^0, which determines the corresponding fair prices. Finally, for the fixed parameter δ, the equations (19)–(20) represent demand and supply curves for REDD options.

3.3. Modeling Results

Experiments are carried out for the discrete approximation of a uniform price distribution:

$$p_l^c=10\left(l-1\right), w_l=\frac{1}{M},\ l=1,..,M. \tag{21}$$

The range of prices, M = 9, is taken from modeling results in Section 2. Sizes of REDD-based option contracts used in the model are taken from the range determined by the optimal emissions generated by the electricity producer: from 8 Mt CO_2 to 83.5 Mt CO_2(see Fig. 6).Below we consider different values of parameter δ which determines the proportion ofsharing the CO_2 price.

The supply-demand curves for REDD options are presented in Fig. 7. They show that if both electricity producers and forest owners have a

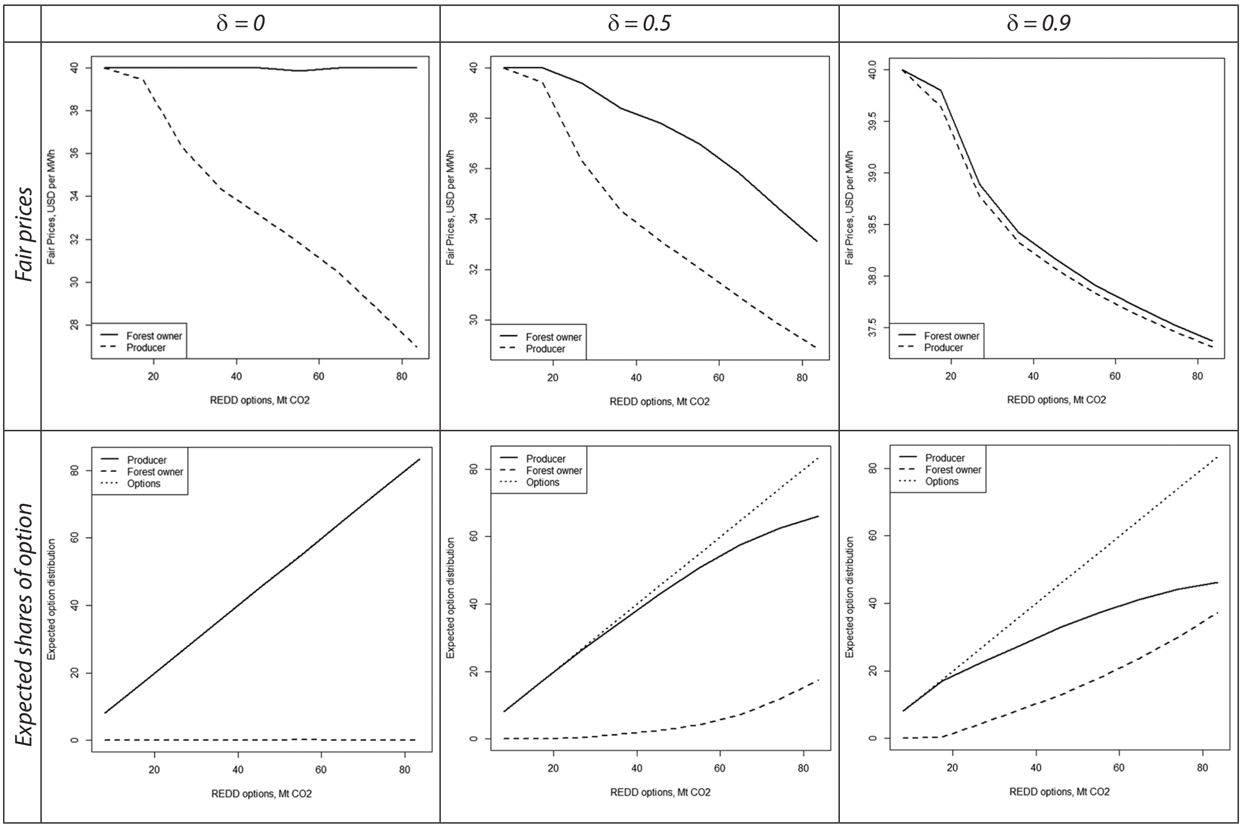

Fig. 7. *Upper panel: Fair prices of electricity producer and forest owner (y-axis) for a contracted amount of REDD offsets (x-axis) for a sample CO_2 price distribution. Lower panel: share of the REDD options used by the electricity producer and returned to the forest owner in the second stage of the model*

common view on the distributions of future CO_2 price, the equilibrium quantity exists, which corresponds to the minimum emissions of the electricity producer expected at the second stage. This amount corresponds to the maximum expected CO_2 price — the right-hand side boundary of the discrete CO_2 price interval $\hat{E}(p^c = 80) = 8$ Mt CO_2. The equilibrium fair price in this case is the mean expected market price $p_F = p_G = \overline{p}^c = 40$ USD/ton. For any amount of options larger than the minimum value, the fair price of the forest owner (20) is higher than the fair price of the electricity producer (19). The magnitude of the gap between fair prices depends on the value of the parameter δ: for larger δ the gap is smaller.

If $\delta = 1$, the forest owner and electricity producer will always negotiate the same price $p_F = p_G = \overline{p}^c$, as in this case it effectively implies the possibility to sell any amount of offsets at the market price at the second stage by any party. The equality also follows from the equations (19)–(20). This is a degenerate case in the sense that the technology mixis not affected as well as the electricity prices for the consumer.

On Fig. 7 (lower panel), we show the expected percentage of unused REDD offsets that are sold on the market by the electricity producer for selected values of δ when the producer initially purchases a certain amount at their respective fair price. The higher the share δ of the electricity producer in the profit from selling those offsets on the market is, the more he decides to not use them for his own emissions offsetting and sells them instead at the second stage. When parameter δ equals zero, the electricity producer does not return any of options to the forest owner.

In Fig. 8 and Fig. 9, one can see the impact of options on the expected electricity prices and emissions with respect to the amount of contracted REDD-based options for $\delta = 0.5$. Results show that in the case of larger amounts $E^0 > 8$ Mt CO_2 of REDD-based options the electricity producers will increase their expected emissions (keeping their expected profits on the same level), and by doing so will be able to reduce the electricity price. For example, if the electricity producer could buy REDD options of the volume 83.5 Mt CO_2 for his fair price $p_G = 28.87$ USD/ton (which is less than $p_F = 33.11$ USD/ton, see Fig. 7), then the expected emissions would be 67.56 Mt CO_2 instead of 43.38 Mt CO_2, (Fig. 9) and the expected electricity price would be 115.8 USD/MWh versus 147.3 USD/MWh (Fig. 8). Apparently, somebody would have to pay for this positive effect (for electricity consumer) as the fair prices of the forest owner are higher than what producer is willing to pay (see Fig. 7).

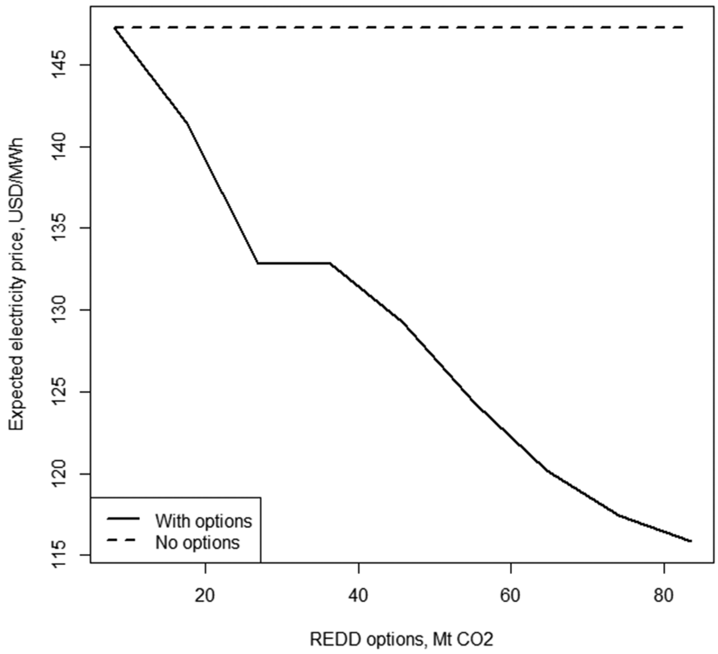

Fig. 8. *Expected electricity price with options bought by electricity producer at their «fair» price (δ = 0.5) vs. without*

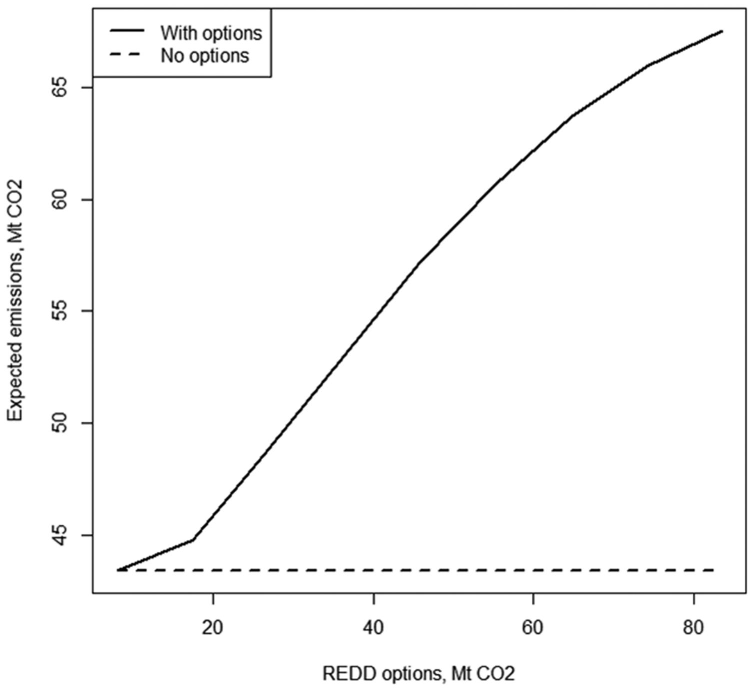

Fig. 9. *Expected emissions with options bought by electricity producer at their «fair» price (δ = 0.5) vs. without*

Conclusions

In this paper, we proposed a partial equilibrium microeconomic model of the interaction of the electricity producer, forest owner and electricity consumer. We illustrated how the optimal decision of the electricity producer changes in the short term when a CO_2 price for emissions is introduced. The electricity producer adjusts its capacity factors of technologies, reduces the production and partially delegates the CO_2 price to the consumer by charging a higher electricity price. Due to the nonlinearities in the marginal cost function constructed for each CO_2 price the dependencies of the optimal profits, emissions and electricity prices with respect to growing CO_2prices are nonlinear. In order to introduce the potential role of REDD as a hedging instrument we consider a two stage stochastic optimization model with uncertainty about future CO_2 prices. We analyze negotiations of the forest owner and electricity producer on the amount of REDD-based options and their fair prices under assumption of fully open information on profits/emissions of producer and a common view on a future CO_2 price distribution. To construct supply-demand curves for REDD options we employ a uniform distribution of the CO_2 price. We show that there is an equilibrium quantity for which fair prices coincide — the supply and demand curves intersect. For larger amounts of options higher emissions can be generated by the electricity producer leading to lower electricity prices for consumers. These positive impacts need additional money to fill in the gap between fair prices of forest owner and electricity producer.

Further possible developments of the study are connected with implementation of additional factors into the model. Namely, additional procedures can be implemented to calculate the costs of electricity production which are based on the fuel prices. The green energy companies as well as nuclear generators influencing the electricity price can also be implemented in the model. From the electricity demand side one can investigate the possibility of a dynamic hourly demand with the market power of the producer at particular hours in order to avoid the assumption of proportional changes. Also feedbacks on the consumer side can be analyzed, e.g. demand response to electric cars, green technologies, etc. The latter are connected with extending the model to a long-term analysis. One should also mention that the use of variable costs and emission factors in the study provides the flexibility for implementing various technologies into the model.

In the model of fair prices, and corresponding supply and demand curves for REDD options one could introduce a more sophisticated utility of the forest owner, e.g. including forest management costs, etc. Further model developments could be made by introducing heterogeneous forest owners and electricity producers. One could also perform the sensitivity analysis with respect to different distributions of CO_2 prices and consider the cases when the electricity producer and forest owner face different distributions. The model with two different electricity producers and forest owners could already lead to interesting problems of searching for the equilibrium fair prices.

Although the current mode is based on several simplified assumptions, from the methodological point of view it provides useful insights and creates the basis for future research. The results provided in the paper are consistent with the literature on modeling the electricity sector and REDD. They propose a relevant financial instrument contributing to the REDD mechanism. This instrument is flexible enough due to possibility of sensitivity analysis with respect to the parameter $\delta \in [0, 1]$. It supports REDD, and provides a potential for reducing risk — softens CO_2 price impacts on regional electricity producers and consumers.

This research has received funding from the project «Options Market and Risk-Reduction Tools for REDD+» funded by the Norwegian Agency for Development Cooperation under agreement number QZA-0464 QZA-13/0074. We are grateful to Dr. Wolf Heinrich Reuter for comments and discussions.

References

1. Lubowski, R. N. & Rose S. K. (2013). The Potential for REDD+: Key Economic Modeling Insights and Issues. *Review of Environmental Economics and Policy,* 7, 67–90.

2. Benítez, P. C. & Obersteiner M. (2006). Site identification for carbon sequestration in Latin America: A grid-based economic approach. *For Policy Econ* , 8, 636–651.

3. Busch, J, Lubowski, R. N., Godoy, F., Steininger, M., Yusuf, A.A., Austin, K., Hewson, J., Juhn, D., Farid, M. & Boltz, F. (2012). Structuring economic incentives to reduce emissions from deforestation within Indonesia. *Proceedings of the National Academy of Sciences* , 109, 1062–1067.

4. Golub, A., Hertel, T., Lee, H-L., Rose, S. & Sohngen, B. (2009). The opportunity cost of land use and the global potential for greenhouse gas mitigation in agriculture and forestry. *Resource and Energy Economics,* 31, 299–319.

5. Bosetti, V., Lubowski, R., Golub, A. & Markandya, A. (2011). Linking reduced deforestation and a global carbon market: implications for clean energy technology and policy flexibility. *Environment and Development Economics* , 16, 479–505.

6. Stoft, S. (2002). *Power System Economics: Designing Markets for Electricity.* Piscataway, NJ: New York: IEEE Press ; Wiley-Interscience, 468.

7. Hunt, L. C. & Evans, J. (2009). *International Handbook on the Economics of Energy.* Cheltenham, UK; Northampton, MA: Edward Elgar, 831.

8. Krey, V. (2014). Global energy-climate scenarios and models: a review: Global energy-climate scenarios and models. *Wiley Interdisciplinary Reviews: Energy and Environment,* 3, 363–383.

9. Obersteiner, M., Huettner, M., Kraxner, F., McCallum, I., Aoki, K., Böttcher, H., Fritz, S., Gusti, M., Havlik, P., Kindermann, G., Rametsteiner, E. & Reyers, B. (2009). On fair, effective and efficient REDD mechanism design. *Carbon Balance and Management* , 4, 1-11.

10. Fuss, S., Szolgayova, J., Golub, A. & Obersteiner, M. (2010). Options on low-cost abatement and investment in the energy sector: new perspectives on REDD. *Environment and Development Economics* , 16, 507–525.

11. Weert, F. de (2013). *An Introduction to Options Trading* . Hoboken, N. J.: Wiley, 176.

12. Shiryaev, A. N., Kabanov, Y. M., Kramkov, O. D., Melnikov, A. V. (1995). Toward the Theory of Pricing of Options of Both European and American Types. I. Discrete time. *Theory of Probability and Its Applications,* 39, 14–60.

13. Dantzig, G. B. (1955). Linear Programming under Uncertainty. *Management Science,* 1, 197–206.

14. Cassano, M. & Sick, G. (2013). Valuation of a spark spread: an LM6000 power plant. *European Journal of Finance,* 19, 689–714.

15. Masters, G. M. (2004). *Renewable and Efficient Electric Power Systems.* Wiley, 680.

16. Szolgayová, J., Fuss, S., Khabarov, N. & Obersteiner, M. (2011). Robust Energy Portfolios Under Climate Policy and Socioeconomic Uncertainty. *Environmental Modeling & Assessment,* 17, 39–49.

17. Andersen, F. M., Larsen, H. V. & Boomsma, T. K. (2013). Long-term forecasting of hourly electricity load: Identification of consumption profiles and segmentation of customers. *Energy Conversion and Management,* 68, 244–252.

18. Bigerna, S., BOLLINO, C. A. (2013). *Hourly Electricity Demand in Italian Market. Quaderni del Dipartimento di Economia, Finanza e Statistica.* Universita di Perugia, Dipartimento Economia, Finanza e Statistica, 24.

19. Stokes, M., Rylatt, M. & Lomas, K. (2004). A simple model of domestic lighting demand. *Energy Build* 36, 103–116.

20. Saravanan, B., Das, S., Sikri, S. & Kothari, D. P. (2013). A solution to the unit commitment problem—a review. *Front Energy,* 7, 223–236.

21. Janssen M, Wobben M: Electricity pricing and market power-evidence from Germany. *Eur Trans Electr Power* 2009, 19:591–611.

22. Bohi, D. R. (2013). *Analyzing Demand Behavior: A Study of Energy Elasticities.* Routledge, 177 .

23. Varian, H. R. (2009). *Intermediate Microeconomics: A Modern Approach.* New York: W.W. Norton & Co., 780.

24. Weisser, D. (2007). A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies. *Energy,* 32, 1543–1559.

Information about the authors

Krasovskii Andrey Andreyevich (Laxenburg, Austria) — PhD, Research Scholar of Ecosystems Services and Management Program (ESM), International Institute for Applied Systems Analysis (IIASA) (1, Schlossplatz, Laxenburg A-2361, Austria, e-mail: krasov@iiasa.ac.at).

Khabarov Nikolay Vasil'evich (Laxenburg, Austria) — PhD, Research Scholar of Ecosystems Services and Management Program (ESM), International Institute for Applied Systems Analysis (IIASA) (1, Schlossplatz, Laxenburg A-2361, Austria, e-mail: khabarov@iiasa.ac.at).

Obersteiner Michael (Laxenburg, Austria) — PhD, Program Director of Ecosystems Services and Management Program (ESM), International Institute for Applied Systems Analysis (IIASA) (1, Schlossplatz, Laxenburg A-2361, Austria, e-mail: oberstei@iiasa.ac.at).