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Mathias Mier, Jacqueline Adelowo

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Poschingerstr. 5, 81679 Munich, Germany
Telephone +49(0)89 9224 0, Telefax +49(0)89 985369, email ifo@ifo.de
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Abstract

Energy system and power market models refrain from distinguishing between private and social discount rates. We devise a strategy to account for diverging private and social discount rates in intertemporal optimization frameworks, resulting in an optimal carbon tax above the marginal damage when private discount rates exceed the social one. We quantify results for the European power market until 2050. Not distinguishing between private and social discount rates yields carbon emissions of 0.83 Gt in 2050 with rising trend from 2020 onwards. Distinguishing between private and social discount rates achieves full decarbonization (–0.15 Gt in 2050) and avoids damages of 1,386 billion € until 2050. Results explain missing investments of firms and suggest that policymakers should announce high future carbon prices to incentivize sufficient investments into clean technologies.

JEL code: C61, H21, H23, H43, L94
Keywords: Carbon taxation, discounting, social cost, carbon emission, externality, intertemporal optimization, power market model, decarbonization

Mathias Mier*
ifo Institute – Leibniz Institute for Economic Research
at the University of Munich
Poschingerstr. 5
81679 Munich, Germany
mier@ifo.de

Jacqueline Adelowo
ifo Institute – Leibniz Institute for Economic Research
at the University of Munich
Poschingerstr. 5
81679 Munich, Germany
adelowo@ifo.de

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* Corresponding author.

1. Introduction

Climate change calls for prompt action by policymakers and firms. Policymakers need to price carbon emissions and firms need to steer investments accordingly. Policymakers apply social discount rates to calculate the social cost of carbon (SCC). Taxing carbon emissions at their marginal damages (i.e., specific SCC) is seen as the *efficient* way to limit the magnitude of climate change. However, firms' investment decisions are subject to their private discount rates, which are in general higher than social ones. Consequently, firms discount future tax payments to a larger extent than a social planner intends. This leads to an incomplete internalization of damages, which diminishes investments into cleaner technologies. This is particularly important considering that investment decisions take place at least a decade before infrastructure such as power plants become operative. We account for this misaligned behavior resulting from diverging private and social discount rates and quantify results for the European power market until 2050.

The literature agrees that social and private discount rates differ (von Below, 2012, Belfiori, 2017, 2018, Barrage, 2018). Climate change impacts should be discounted with the lowest possible discount rate due to their long-lasting and intergenerational effects (Weitzman, 1998). In turn, firm discount rates follow from capital market interest rates (Steinbach, 2015). However, given that CO_2 emissions on the one hand, and investments, variable as well as fixed cost of firms on the other hand have diverging discount rates, we encounter a problem of setting optimal intertemporal tax rates on CO_2. We show that intertemporal models aiming to reflect firm behavior need to tax CO_2 at rates above their marginal damages for full internalization, because their social discount rates lie below those of firms. This finding corresponds to those of Belfiori (2017) and Barrage (2018). Belfiori (2017) shows that the optimal carbon tax does not equal the SCC in general and that social discount rates are below those of private individuals. Barrage (2018) highlights that social planners and households discount the future differently. Additional intertemporal effects distort optimal decisions in general equilibrium, requiring massive taxation decisions to restore efficiency. However, only few papers address the role of discount rates in energy system or similar models. Steinbach (2015) argues that social discount rates differ from private ones and gives guidance on how to determine those rates. García-Gusano et al. (2016), Mier and Azarova (2021a), and Mier and Azarova (2021b) show that diverging discount rates considerably impact results.[1]

We internalize SCC via taxes in an intertemporal optimization framework. We hereby account for the fact that firms evaluate their cash flows (investment, fixed, and variable cost as well as taxes) with higher discount rates than a social planner would evaluate social cost. We implement this strategy in EUREGEN, a multi-region partial equilibrium *model* of the European power market that optimizes investments, dispatch, and decommissioning of multiple generation, storage, and transmission technologies from 2020 to 2050.

Our general theoretical contribution demonstrates how diverging social and private discount rates can be implemented simultaneously in an intertemporal optimizing framework (such as inte-

[1] This paper is a substantial expansion of Mier et al. (2021) but focuses on the taxation of carbon emissions only. The taxation of air pollution is analyzed in another succeeding work.

grated assessment, energy system, and power market models). This makes it possible to evaluate firms' cash flows differently from social cost occurring from carbon emissions.[2] Social discount rates being lower than private ones, combined with the existence of emissions, requires taxing CO_2 emissions at rates above their marginal damages. Applying a pure rate of time preference (PRTP) of 1%, consumption growth of 1.94%, and an elasticity of marginal utility of consumption of 1.45, yields a social discount rate of 3.81% when applying the Ramsey formula. Further assuming SCC of 95 €/ton in 2050 and a private discount rate of 7%, demands an optimal CO_2 tax of 257 €/ton because firms discount tax-inclusive cash flows (of their variable cost) differently from a social planner.

Our numerical contribution delivers insights into how the technology and emission mix of the European power system varies under different taxation choices. A business-as-usual policy—which neglects the fact that private discount rates are above social ones—is not sufficient to spur investments into carbon-capture-and-storage as well as nuclear so that CO_2 emissions are at 0.83 Gt in 2050. The optimal policy in turn—that accounts for diverging private and social discount rates and sets carbon tax rates socially optimal—reduces emissions to –0.15 Gt and reduces accumulated damages from emitting CO_2 by 1,386 billion € until 2050. Electricity prices are higher for such an optimal policy compared to a business-as-usual policy, but in fact carbon tax shares are lower (and even negative in later periods due to negative overall emissions).

Section 2 introduces the modeling strategy within an intertemporal optimization framework and optimal taxation following from diverging private and social discount rates. Section 3 presents the calibration by focusing on social cost and the role of discounting. Sections 4 presents results including sensitivities. Section 5 concludes.

2. Modeling strategy

We seek to develop a modeling framework where a social planner sets tax rates for carbon emissions so that competitive firms consider social damages over time similarly as a social planner would do. In particular, we consider the problem of electricity generation and related CO_2 emissions. We start with our notation (Subsection 2.1) and the demand constraints (Subsection 2.2). A detailed set of generation, storage, and transmission constraints is presented in Appendix A. We then derive private and social cost, present the objective, and show how to set tax rates intertemporally optimally given diverging private and social discount rates (Subsection 2.3).

2.1. Notation

Generation. Denote generation technologies by i and regions by r. h indicates the respective hour, t is the current year (period), and v is the year of installation (vintage). We use subscripts i, r

[2] Our framework also allows to use diverging social discount rates to evaluate different kinds of social cost. Consider the example of additional air pollution damages. A lower social discount rate for damages from CO_2 emissions can be justified by the intergenerational effects of climate change, thereby assuming that air pollution effects occur only in the present generation.

and parentheses (h, v, t) to denote parameters and variables. Y is generation (in GWh), Q are generation capacities, and IQ investments into generation capacity (both in GW). Thus, $Y_{ir}(h, v, t)$ is generation of technology i in region r in hour h and period t from capacity $Q_{ir}(v, t)$ that is originally installed as $IQ_{ir}(v)$ in vintage v.[3]

Storage. Denote storage technologies by j. GC is storage charge, GD is storage discharge (both in GWh), GQ is the storage (charge and discharge) capacity (e.g., pumps and turbines), GIQ investments into storage capacity (both in GW), $ghours$ (in hours) describes the relation of storage capacity to the maximum feasible amount of stored energy (e.g., reservoir size), and GB is the storage balance (in GWh).[4]

Transmission. Denote transmission technologies by k. rr is a subset of regions. In particular, $\mu_{k,r-rr}$ describes the mapping of regions that are eligible for transmission exchange (for each technology). E is the bilateral trade flow (in GWh), TQ transmission capacity, and TIQ investments into transmission capacity (both in GW).

2.2. Demand constraints

Supply-equals-demand. Suppose that $\eta \in (0, 1)$ are process efficiencies. $x_r(h, t)$ is demand and η_r^{loss} the distribution grid efficiency. Moreover, $L_r(h, t)$ is lost load. $\eta_{k,rr-r}^{im}$ is the import efficiency accounting for transmission losses that occur on the importing side (r is the importing region) and $\eta_{k,r-rr}^{ex}$ is the export efficiency (r is the exporting region). Both are always specific to the respective region pair. Moreover, η^{gd} is the discharge efficiency reflecting the loss when releasing stored energy. We can now define the *demand-equals-supply constraint* as

$$\begin{aligned} \frac{x_r(h,t)}{\eta_r^{loss}} &= \frac{L_r(h,t)}{\eta_r^{loss}} + \sum_{i,v} Y_{ir}(h,v,t) \\ &+ \sum_{j,v \leq t} \Big(GD_{jr}(h,v,t)\, \eta_{jr}^{gd}(v) - GC_{jr}(h,v,t) \Big) \\ &+ \sum_{\mu_{k,rr-r}} E_{k,rr-r}(h,t)\, \eta_{k,rr-r}^{im} - \sum_{\mu_{k,r-rr}} \frac{E_{k,r-rr}(h,t)}{\eta_{k,r-rr}^{ex}} \quad \forall \quad (h,r,t). \end{aligned} \tag{1}$$

Note that demand on the left side of the equality sign in the first line is a parameter (indicated by not using capital letters). The right side satisfies demand but the satisfaction must be higher by the region-specific distribution losses. The first line on the right side contains lost load and aggregate generation. Lost load (first term) is subject to distribution losses as well. Aggregate generation in turn is not (second term). The second line contains the difference between storage

[3]Endogenous decommissioning allows for $IQ < Q$.

[4]We simplify the complexity of storage by assuming that charge and discharge capacity are the same. We also assume a fixed relation between (charge and discharge) capacity and the storage size.

discharge and charge. Discharge is subject to discharge losses because less than one unit arrives at the market. Charge in turn is not because GC is the amount taken from the market. The third line contains the difference between imports (first term) and exports (second term). Imports and exports are subject to transmission losses that depend on the underlying transmission technology and the region pair.

Resource adequacy. Besides the classic demand-equals-supply constraint there is a resource adequacy constraint that ensures that there is sufficient back-up capacity in each region to meet demand. This constraint can be interpreted as the outcome of a reserve market. We apply capacity credits *cred* that indicate the amount of secured capacity. As a consequence, the resource adequacy constraint is only binding in the peak period of each region h_r^{peak}, i.e.,

$$\begin{aligned} \frac{x_r(h,t)}{\eta_r^{loss}} &= \sum_{i,v} cred_i \cdot Q_{ir}(v,t) \\ &+ \sum_{j,v\leq t} cred_j \cdot GQ_{jr}(h,v,t)\,\eta_{jr}^{gd}(v) \\ &+ \sum_{\mu_{k,rr-r},v} cred_k \cdot TQ_{k,v,rr-r}(h,t)\,\eta_{k,rr-r}^{im} \quad \forall \quad \left(h_r^{peak},t\right). \end{aligned} \tag{2}$$

The first line contains secured generation capacity, the second line depicts secured storage capacity (for discharge), and the third line presents secured transmission capacity (for imports). The assumptions about secured discharge and transmission are of course difficult to make because whether or not the storage is empty or full, respectively, is endogenous to the optimization. Also scarcity in other regions plays a role. As a consequence, the secured storage and transmission capacity is at 10%, while the secured generation capacity is around 90% for non-intermittent renewables. Solar PV in fact has 0% secured capacity, whereas wind has around 5%. Note that this constraint does not prevent per se the occurrence of lost load, because storages can be empty, imports not possible or too costly, or wind power not available at all. However, the constraint favors secured capacity in the optimization game and generally reduces the occurrence of lost load.

2.3. Cost and optimization problem

Private cost. Capacity investments are costly, $c_{ir}^{IQ}(v), c_{jr}^{GIQ}(v), c_{k,r-rr}^{TIQ}(v) > 0$ (in €/GW), holding capacity is costly, $c_{ir}^{Q}(v,t), c_{jr}^{GQ}(v,t), c_{k,r-rr}^{TQ}(v,t) > 0$ (in €/GW*a), and generation is costly as well, $c_{ir}^{Y}(v,t) > 0$ (in €/GWh). We assume no further variable cost for storage operations and transfers.[5] Moreover, lost load costs $c_r^L(t) > 0$ (in €/GWh). Private cost per region and time period $C_r(t)$ (in €) are then given by

[5]Remember that losses apply on the importing and exporting side. Moreover, charge, discharge, and hourly losses reflect variable cost of storage operations.

$$
\begin{aligned}
C_r(t) \;=\;& c_r^L(t)\sum_h L_r(h,t) + \\
& \sum_i \left[\sum_{v=t} c_{ir}^{IQ}(v)\, IQ_{ir}(v)\,\Gamma_i(v,t) + \sum_{v\le t} c_{ir}^{Q}(v,t)\, Q_{ir}(v,t) + \sum_{v\le t} c_{ir}^{Y}(v,t)\sum_h Y_{ir}(h,v,t)\right] \\
& + \sum_j \left[\sum_{v=t} c_{jr}^{GIQ}(v)\, GIQ_{jr}(v)\,\Gamma_j(v,t) + \sum_{v\le t} c_{jr}^{GQ}(v,t)\, GQ_{jr}(v,t)\right] \\
& + \sum_k \sum_{rr\neq r} \left[\sum_{v=t} c_{k,r-rr}^{TIQ}(v)\, TIQ_{k,r-rr}(v)\,\Gamma_k(v,t) + \sum_{v\le t} c_{k,r-rr}^{Q}(v,t)\, TQ_{k,r-rr}(v,t)\right], \quad (3)
\end{aligned}
$$

where $\Gamma(v,t)$ is the fraction of investment cost that should be considered within the planning horizon (called *endeffect*). In particular, $\Gamma(v,t)=1$ when the depreciation time of an investment is completely within the planning horizon (from t until t^{end}), and $\Gamma(v,t)<1$ when the depreciation time of an investment spans beyond the planning horizon (depreciates longer than t^{end}). This endeffect is calculated on the basis of private discount rates and the time outside the planning horizon. The first line of (3) reflects cost of lost load, the second line generation cost, the third line storage cost, and the fourth line transmission cost.

Social cost. Denote by $scc(t)$ the specific social cost of carbon (SCC, in €/ton). Carbon emission factors $\xi_i(v)$ (in ton/GWh thermal) and power plant efficiencies $\eta_i(v)$ depend on the vintage, that is, older vintages have lower efficiencies and higher emission factors leading to higher emissions. In particular, $\sum_{v\le t}\sum_h \frac{1}{\eta_i(v)} Y_{ir}(h,v,t)$ is total fuel used per technology in period t (in GWh thermal). Multiplying this total fuel used with the respective emission factors yields CO_2 emissions EM (in ton):

$$
EM_r(t) \;=\; \sum_i \xi_i(v)\sum_{v\le t}\sum_h \frac{Y_{ir}(h,v,t)}{\eta_i(v)}. \quad (4)
$$

Multiplying those emissions with the respective specific social cost yields total social cost $SC_r(t)$ (in €), i.e.,

$$
SC_r(t) \;=\; scc(t)\, EM_r(t). \quad (5)
$$

Objective. Intertemporally optimizing models evaluate cash flows according to the social discount rate (from a social planner perspective) or according to the private discount rate (from a private firm perspective). Assume that ν is the *private discount rate* (PDR) and $\delta(t) = 1/(1-\nu)^{t-t^{base}}$ is the corresponding *private discount factor* (PDF). Moreover, ν^{soc} is the *social discount rate* (SDR)

and $\delta^{soc}(t) = 1/(1-\nu^{soc})^{t-t^{base}}$ is the corresponding *social discount factor* (SDF). We assume $\nu^{soc} \leq \nu$ so that $\delta^{soc}(t) \geq \delta(t)$ to reflect myopic behavior of firms, long-term looking behavior of social planners, and higher financing cost of private firms (compared to governmental entities).

We combine private cost from a firm perspective and social cost from a social planner perspective in a joint objective by using the respective private discount factor for private cost and the social discount factor for social cost. We obtain

$$\min_{\mathbf{IQ},\mathbf{Q},\mathbf{Y}} \quad \sum_{t,r} \quad [\delta(t) C_r(t) + \delta^{soc}(t) SC_r(t)], \tag{6}$$

where **IQ** is the vector of generation, storage, and transmission investment decisions, **Q** is the vector of capacity decisions for the three types of capacities, and **Y** contains generation, charge and discharge, as well as trade decisions. Note that $C(t), SC(t)$ are measured in current values. In turn, $\delta(t) C(t)$ represents the present value of private costs and $\delta^{soc}(t) SC(t)$, respectively, the present value of social cost.

Taxation. Another way to achieve the same outcome is to implement a carbon tax $\tau^{car}(t)$. The objective changes to

$$\min_{\mathbf{IQ},\mathbf{Q},\mathbf{Y}} \quad \sum_{t,r} \quad \delta(t) [C_r(t) + \tau(t) EM_r(t)]. \tag{7}$$

The two objectives are equivalent when the social planner sets optimal tax rates of

$$\tau(t)^* \quad = \quad scc(t) \frac{\delta^{sco}(t)}{\delta(t)}. \tag{8}$$

Observe that those tax rates are higher than the respective social cost by $\frac{\delta^{soc}(t)}{\delta(t)} \geq 1$ because firms discount cash flows more than a social planner discounts carbon emission damages.

3. Implementation and calibration

We start by describing the general setup of the EUREGEN model (Subsection 3.1) and the used set of technologies (Subsection 3.2). Next, we show how we calculate the social cost of carbon (Subsection 3.3). Finally, we describe the applied discount rates and resulting optimal carbon tax rates (Subsection 3.4).

3.1. Setup

We translate the modeling strategy into EUREGEN (Weissbart and Blanford, 2019), which is a multi-region partial equilibrium model of the European power market with perfect foresight (i.e., intertemporal optimization) that optimizes overall system cost—i.e., investments, holding and decommissioning of capacity, and dispatch of multiple generation, storage, and transmission technologies—intertemporally from 2015 (base year) to 2050 (end year). The period 2020 is the

first period of endogenous decommissioning and capacity investments. In fact, we work with an adjusted 2015 calibration that already accounts for investments that happen within the period 2016 to 2020. EUREGEN chooses between different discount and interest rates, investor types or investment cost specifications, respectively, and spatial resolutions (Mier and Azarova, 2021a,b). We opt for the *normal* investor (specification) that carries (places) cost of investments within the period of investment and uses endeffects when the investment's depreciation extends beyond the model horizon (see Equation (3) in Section 2). Moreover, we apply the maximum spatial resolution of 28 countries (EU27 less the island states of Cyprus and Malta, including Norway, Switzerland, and United Kingdom) and an hour choice algorithm to reduce the hourly resolution for sake of numerical feasibility.[6] EUREGEN uses the CGE model PACE to calibrate for annual electricity demand and major fuel prices (see Tables B.1 and B.2 in Appendix B).[7] EUREGEN calculates CO_2 emissions from an emission factor and can either implement a carbon price (e.g., Mier et al., 2020, 2022, Siala et al., 2022) or a quantity target (e.g., Weissbart, 2020, Azarova and Mier, 2021). We refrain from using carbon prices resulting from the CGE calibration or quantity targets as imposed for instance by the EU ETS and instead apply optimal carbon taxes that follow from SCC and the respective differential between social and private discount factors.

3.2. Technologies

We consider steam turbines burning biomass (*bioenergy*), biomass with carbon-capture and storage (*bio-CCS*), *coal*, *coal-CCS*, *lignite*, and natural gas (*gas-ST*). This portfolio is enriched by combined-cycle gas turbines burning natural gas without (*gas-CCGT*) and with carbon-capture and storage (*gas-CCS*), open-cycle gas turbines burning natural gas (*gas-OCGT*), and gas turbines or engines, respectively, using oil and other non-biomass non-natural gas fuels (*oil*).[8] We further consider *nuclear* and *geothermal* plants. *Hydro*, *wind onshore*, *wind offshore*, and *solar PV* are intermittent technologies with hourly-varying availability factors. We consider two different turbine heights (80m for current fleet, 100m for future vintages) for wind onshore and offshore. Hydro expansion is restricted to existing capacity. Wind and solar expansion is restricted to resource potentials that are differentiated by quality classes (high, mid, and low). We further differentiate three storage technologies (pump hydro, batteries, and power-to-gas). Similarly to hydro, expansion of pump hydro is restricted to existing capacity. Transmission technologies are represented by AC lines as well as DC cables.[9] Appendix C summarizes efficiencies, emission factors, and

[6]The hour choice algorithm selects and weights hours that present the extremes of load, wind onshore, wind offshore, solar, and hydro generation. We obtain 280 hours and finally scale timeseries to match annual demand and full-load hours of all intermittent technologies.

[7]For more details of the used GREEN scenario with almost unconstrained transmission expansion from 2035 onwards see Mier et al. (2020, 2022), Siala et al. (2022).

[8]We refrain from depicting combined-heat-and-power (CHP) plants for four reasons: (1) CHP power plants are must-run technologies due to heating demand. (2) There is substantial change going on in the heating sector. (3) Decarbonization discourages burning fossil fuels for heating anymore, making most existing CHP plants obsolete. (4) Electrification in heating is considered by the CGE calibration.

[9]DC cables mainly apply to connecting countries that are divided by water.

investment cost of technologies.

3.3. Social cost of carbon

We calculate specific SCC by using a calibrated version of the DICE model.[10]. The CGE model used to calibrate the EUREGEN model projects GDP development until 2050 and underlying population projections are taken from the World Bank (see Appendix D). In the DICE model, 2015 world GDP is 105.5 trillion 2010-US$. We translate this value to 86.1 trillion 2015–US$. Additionally, we scale total factor productivity by 0.8254 to match 2020 global CO_2 emission of 39.6 Gt. We further adjust population and total factor productivity from 2020 to 2050 to precisely match World Bank (population) and CGE (GDP) projections (see DICE calibration in Table 1). Finally, we change the DICE pure rate of time preference (PRTP) from 1.5% to 1% but keep the default elasticity of marginal utility of consumption of 1.45.[11] Our calibrated DICE model expands GDP from 10,661 €/capita in 2015 to 20,335 €/capita in 2050. Average consumption growth is at 1.94%. This leads to a social discount rate (SDR) of 3.81%.[12]

Table 1: DICE calibration and output

		2020	2030	2040	2050
DICE calibration	Gross world GDP (trillion 2015-$)	99.7	131.5	171.7	216.6
	World population (billion)	7.75	8.50	9.14	9.68
DICE output	SCC ($/ton)	46.86	61.30	80.44	104.88
	CO_2 emissions (Gt)	39.60	37.01	37.29	36.45
	Atmosphere temperature increase (°C)	1.02	1.36	1.71	2.04
Conversion in €	SCC (€/ton)	42.60	55.73	73.13	95.35

We apply an exchange rate of 1.1 to convert US-$ into €, i.e., 1 € is worth 1.1 US-$ in 2015.

Table 1 also presents selected DICE output. We obtain specific SCC of 47 $/ton in 2020 and 105 $/ton in 2050.[13] Observe that (global) carbon emissions remain almost constant, leading to a temperature increase of above 1.5° (2.0°) Celsius already in 2040 (2050). We are aware that

[10]We use DICE-2016R-091216a. GAMS code is available at `http://www.econ.yale.edu/~nordhaus/homepage/homepage/DICE2016R-091916ap.gms`

[11]We decide to lower the PRTP because recent findings of Drupp et al. (2018) suggest lower PRTP and resulting 2050 SCC from the DICE model would be around 62 $/ton otherwise, which is too low given recent findings and discussions of carbon damages.

[12]The Ramsey formula states that the SDR is equal to PRTP plus (per capita) consumption growth times the elasticity of marginal utility of consumption, i.e., $0.01 + 0.0194 \times 1.45 = 0.0381$.

[13]Note that DICE maximizes the net present value of utility (from consumption) and thus the specific SCC is calculated according to the fraction of the marginal of the emission equation (in utility units per ton) and the consumption equation (in utility units per $). Utility units are in present values, so that the division of present value utility (per ton) by present value utility (per $) leaves specific SCC in current $/ton. We can thus use the so calculated specific SCC directly again in another discounting framework that uses current values to minimize the net present value of cost.

those predictions do not correspond with targets from the Paris Agreement (2015) nor with recent ambitions of the EU (Green Deal) but are in line with recent findings of Dietz et al. (2021), who also find that the *optimal* path leads to more than 2° Celsius warming. SCC values are even lower in Dietz et al. (2021) compared to our values (applying our default PRTP of 1%). Recently published, the IPCC Sixth Assessment Report also reveals that an extrapolation of current decarbonization policies and *pledges* would still exceed the 1.5° Celsius goal of the Paris Agreement (IPCC Working Group II, 2022).

3.4. Discounting and taxation

The standard discounting in EUREGEN applies a private discount rate (PDR) of 7% to evaluate all cash flows from investments, as well as fixed and variable cost including taxes (private cost). Intertemporal models neglecting the difference between social and private discount rates would apply 7% to evaluate taxes equal to the damages from carbon emissions as well. However, SCC are calculated on the basis of a PRTP of 1% and the resulting SDR is 3.81% (see Subsection 3.3).

Table 2: Social discount factors and resulting carbon tax

	2020	2030	2040	2050
Social discount factor				
Low (BAU)	0.82	0.42	0.21	0.11
Medium	0.85	0.48	0.27	0.16
High	0.87	0.54	0.34	0.21
Optimal	0.89	0.62	0.42	0.29
Resulting carbon tax (in €/ton)				
Low (BAU)	42.60	55.73	73.13	95.35
Medium	43.98	64.29	94.26	137.34
High	45.21	72.67	117.15	187.69
Optimal	46.49	82.24	145.93	257.32

Social discount factors (SDF) represent five year averages, where 2020 covers years 2016 to 2020, ..., and 2050 years 2046 to 2050. *Low* carbon tax presents the business-as-usual (BAU) where there is no differentiation between PDR and SDR. *Optimal* carbon tax presents the social optimum that sets carbon taxes according to Equation 8. *Medium* and *high* carbon tax does not apply the SDR from SCC calculation (3.81%) to determine carbon taxes but rather use 4.81% or 5.81%, respectively.

Given this setup, we analyze four taxation choices and how they effect the technology mix, resulting carbon emissions, and damages. The first taxation choice neglects the difference between PDR and SDR and is the standard way of implementing carbon taxes (or specific SCC) in energy system and power market models. We thus call it *business-as-usual* (BAU) in the remainder. The BAU leads to a *low* carbon tax equal to the specific SCC—43 €/ton in 2020 that rises to 95 €/ton in 2050. The alternative choice is to set the *optimal* carbon tax by using a SDR of 3.81% to calculate a social discount factor (SDF). The resulting carbon tax follows from the specific

SCC and the differential between SDF (fourth line in Table 2) and PDF (first line). The carbon tax rises to 257 €/ton in 2050. We also analyze two in-between solutions of a *medium* and a *high* carbon tax that use 2% or 1% higher SDR.[14] The 2050 carbon taxes are then 137 €/ton (medium carbon tax) or 188 €/ton (high carbon tax), respectively. Those diverging tax choices have particular impact on the technology mix because the absolute magnitude of carbon taxes changes the relative competitiveness of technologies (see technology-specific carbon taxes resulting from different SDR in Appendix E).

4. Results

We start by analyzing the impact of the four taxation choices (low (BAU), medium, high, and optimal; see Table 2) on the generation mix and resulting carbon emissions (Subsection 4.1). Next, we compare accumulated CO_2 emissions and social cost across taxation choices (Subsection 4.2). Finally, we test sensitives of results with respect to the specific SCC level (Subsection 4.3).

4.1. Generation mix and carbon emissions

Figure 1 visualizes the generation mix and resulting carbon emissions from the different taxation choices. The stacked bars depict annual generation by technology (in TWh, left axis). Gray diamonds depict annual CO_2 emissions (in Gt, right axis). 2015 serves as calibration year assuming a joint CO_2 tax of 7.75 €/ton (2015 EU ETS average) and is the same across all specifications. The 2015 technology mix is dominated by nuclear (836 TWh, 25.8%), conventional gas (gas-CCGT, gas-ST, gas-OCGT; 719 TWh, 22.2%), and coal (539 TWh, 16.6%). Hydro (418 TWh, 12.9%), wind (306 TWh, 9.4%), lignite (245 TWh, 7.6%), and solar (109 TWh, 3.4%) are the remaining relevant technologies.[15] Generation from oil, bioenergy, and geothermal plants is negligible. CCS is not employed yet. Corresponding CO_2 emissions are at 1.06 Gt.[16]

Our four analyzed taxation choices are grouped for periods 2020, 2030, 2040, and 2050.[17] In 2020, there is almost no difference across taxation choices because the discounting differential (see Table 2) in 2020 is almost negligible. However, CO_2 emissions are lowest at 0.48 Gt for the optimal carbon tax and highest for the low carbon tax from the business-as-usual (BAU). In particular, wind, bioenergy, and conventional gas production is higher for optimal carbon taxes, whereas BAU relies slightly more on lignite and coal, hinting that the small tax differences (46.5 vs. 42.6 €/ton) already start changing the relative competitiveness of technologies. Our two variations (medium and high carbon tax) perform as expected between low and optimal taxes.

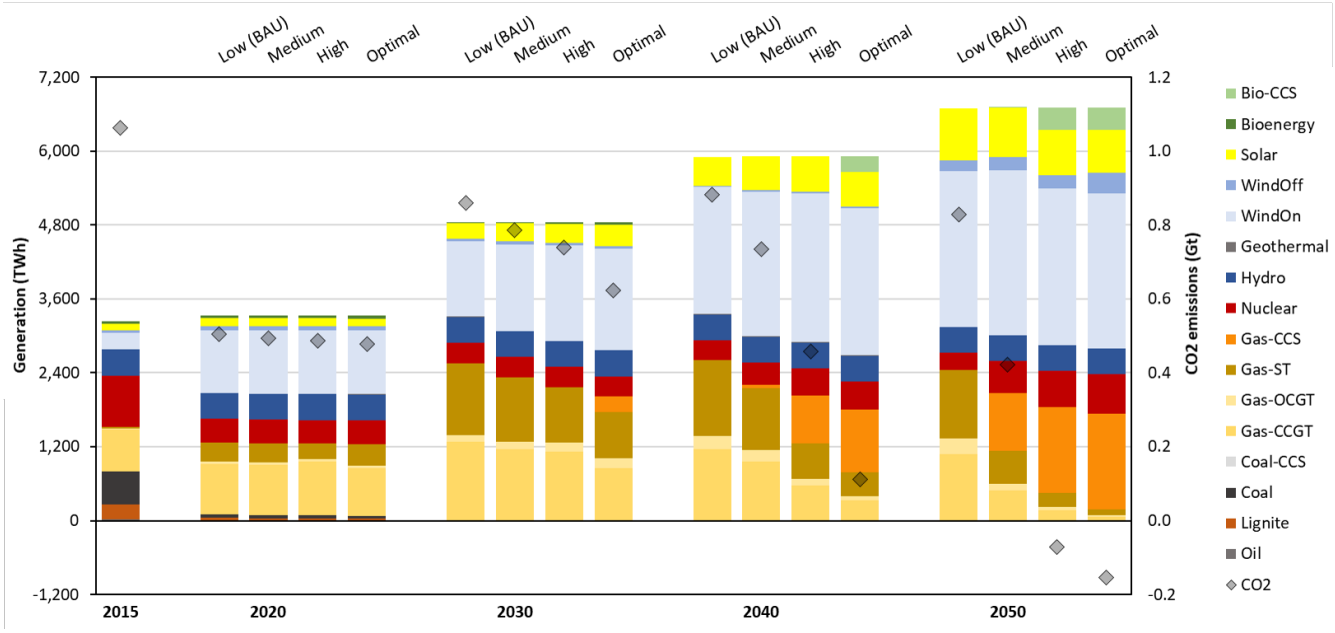
[14] We keep a PRTP of 1% for our DICE calculation and only change the SDR in our optimization framework.

[15] Absolute generation from hydro is the same across all specifications for all periods so that we refrain from mentioning hydro generation in the following.

[16] True 2015 CO_2 emissions from electricity generation were 1.09 Gt, so that our calibration reflects real-world generation quite well.

[17] EUREGEN optimizes in five-year steps. For parsimony, we refrain from presenting 2025, 2035, and 2045 outcomes.

Figure 1: Generation mix and carbon emissions for different taxation choices



Differences between taxation choices grow in 2030 and 2040. All specifications abandon the three dirtiest technologies (oil, lignite, and coal). Instead, conventional gas takes over considerable market shares in 2030. Wind and solar power are successively deployed but their generation shares grow only slightly from 32.5–33.1% in 2020 to 35.3%–41.2% in 2040. Interestingly, 2040 wind and solar power generation is even higher for high carbon tax than for optimal carbon tax. Instead, firms start employing gas-CCS in 2030 (257 TWh, generation share of 5.3%), expand gas-CCS until 2040 (1,014 TWh, 17.1%), and use also bio-CCS in 2040 (258 TWh, share of 4.4%) under optimal carbon tax. Also medium and high carbon tax start employing gas-CCS (medium in 2040, and high in 2035) as well as bio-CCS (both in 2050). Final bio-CCS deployment under optimal carbon tax and under high carbon tax are the same but gas-CCS, nuclear, and wind usage are slightly higher for optimal carbon tax so that final CO_2 emissions are at –0.15 Gt (while high carbon tax delivers –0.07 Gt).

Medium carbon tax deploys bio-CCS but the magnitudes are negligible (2 TWh, 0.04%). However, the wind power share is highest among all specifications (43.2%). BAU in turn neither uses gas-CCS nor bio-CCS and thus has by far highest emissions (0.83 Gt). Observe, however, that electricity generation doubles in the period 2015 to 2050 (due to rising demand). Hence, the final power system is considerably cleaner than the initial one. Moreover, solar generation is indeed highest in BAU because solar generation patterns perfectly match with conventional gas cost structures. The low carbon tax also yields lowest 2050 nuclear generation (282 TWh, 4.2%).

4.2. Emissions and cost assessment

The taxation choice has considerable impact on accumulated carbon emissions and resulting social cost. Table 3 presents accumulated CO_2 emissions (in Gt), accumulated SCC (in current billion €, value in parentheses present the net present value of or discounted SCC, respectively) as well as the amount of carbon taxes (in billion €). Table 3 further shows the European weighted electricity price (in €/MWh) including carbon tax shares in 2020 (first value) and 2050 (second value) with the maximum value in parentheses—e.g., 63.0–73.0 (73.0, 2050) reflects a 2020 price of 63 €/MWh and a 2050 of 73 €/MWh with a maximum price of 73 €/MWh in 2050.

Table 3: Accumulated CO_2 emissions, SCC, and tax yields with price ranges from period 2020 to 2050 for different taxation choices

Taxation choice	CO_2 (Gt)	SCC (*) (billion €)	Tax yield (billion €)	Electricity price (€/MWh) Total	Tax share
Low (BAU)	28.4	1,918 (555)	1,918	63.0–73.0 (73.0, 2050)	7.0–12.7 (12.7, 2050)
Medium	23.3	1,501 (484)	1,871	62.9–75.4 (77.1, 2045)	7.0–9.4 (12.6, 2040)
High	15.9	902 (384)	1,213	62.9–76.2 (78.3, 2035)	7.1–(–2.1) (11.9, 2030)
Optimal	10.8	532 (300)	643	63.1–78.5 (78.6, 2035)	7.2–(–6.4) (11.4, 2030)

The period 2020 to 2050 covers indeed 35 years as period 2020 reflects years 2016 to 2020 and so on. We do not include 2015 in this calculation because the outcomes from the calibration year are the same for all specifications and SCC are not internalized perfectly in this year. *The value in parentheses refers to discounted SCC. Electricity price (total, tax share) ranges are from 2020 to 2050 with the maximum value and the corresponding year in parentheses.

Start with low (BAU). Remember that such a taxation choice yields almost no emission cutbacks. CO_2 emissions accumulate to 28 Gt (0.81 Gt/a). Accumulated SCC are 1,918 billion € (billion €/a) and discounted SCC are 555 billion €. The tax yield is equal to accumulated SCC because the chosen tax rate is equal to the specific SCC.

Now turn to medium. Accumulated CO_2 emissions drop to 23 Gt. The tax yield remains almost unchanged (–47 billion €), while such medium carbon taxes additionally avoid damages of 417 billion €. The tax yield considerably drops for the high carbon tax choice (1,213 billion €). In turn, accumulated SCC are also considerably lower. This pattern continues for the optimal carbon tax choice. Accumulated CO_2 emissions are now at 11 Gt, accumulated SCC at 532 billion € and the corresponding tax yield is at 643 billion €.

The BAU electricity price continuously increases from 2020 to 2050 but this pattern does not hold for the three other taxation choices. For example, under optimal carbon tax electricity prices peak in 2035. In the long run, however, prices are lowest for the low carbon tax from the BAU and highest for optimal carbon tax. Interestingly, the tax share is highest again for low carbon tax (BAU) because for higher taxes overall emissions are considerably lower or even negative.

4.3. Sensitivity analysis

Despite careful calibration, some uncertainty remains regarding specific SCC. We address this uncertainty by additionally modifying specific SCC levels to 25%, 50%, 75%, 125%, 150%, and 200% of the default level (from 2020 onwards). Appendix F visualizes the generation mix and

resulting carbon emissions and also mirrors corresponding accumulated carbon emissions, social cost, tax yields, and price ranges from Table 3.

Generation mix and carbon emissions. 25% SCC is insufficient to induce competitiveness of CCS technologies. Instead, conventional gas technologies substitute for gas-CCS and substantial parts of nuclear generation. The 2050 wind (solar, nuclear) share is 32.6% (11.67%, 4.2%). 50% SCC employs gas-CCS in 2050 but only at a minor generation share of 9.5%. Wind (solar, nuclear) contributes 43% (12.4%, 6.7%). Bio-CCS is not part of the system for 25% and 50% SCC, so that 2050 CO_2 emissions are at 1.03 Gt or 0.53 Gt, respectively. 75% SCC is sufficient to increase bio-CCS (generation share of 5.5%) up to its maximum potential. 2050 wind (solar, nuclear) share is at 41.3% (10.8%, 8.8%) and resulting CO_2 emissions are at –0.07 Gt. Even higher SCC increase wind and nuclear usage, whereas solar shares drop.[18] Moreover, gas-CCS usage is highest for 100% (23.3%) but then drops for higher SCC to the benefit of carbon-neutral nuclear because gas-CCS still has a slightly positive emission factor. However, CO_2 emissions do not fall much further (from –0.15 Gt to –0.21 Gt) when doubling underlying SCC and carbon taxes, because the biomass potential for negative emissions is limited.

Emissions and cost assessment. Accumulated CO_2 emissions increase from 11 Gt (for 100% SCC) to 37 Gt (for 25% SCC) and drop to –2 Gt (for 200% SCC). The accumulated SCC (tax yields) are 622 (1,214) billion € for 25% SCC and –465 (–1,237) billion € for 200% SCC. Prices are lowest for 25% SCC and highest for 200% SCC. The tax share is at –17.5 €/MWh in 2050 for 200% but at 10.7 €/MWh for 25%. These figures inform about how SCC and tax yields deviate when specific SCC levels change accordingly. In particular, SCC (also in discounted terms) and tax yields are similar for 100% SCC (our default calibration) but deviate already by factor two for 25% SCC. Relative differences are even more severe for higher SCC.

5. Conclusion

We determine the optimal carbon tax given that private firms discount their cash flows (and thus taxes) more heavily than a social planner would discount social cost from emitting CO_2 (the social cost of carbon, SCC). We quantify results by implementing the theoretical framework in the EUREGEN model that intertemporally optimizes capacity expansion, decommissioning, and generation of the European power market until 2050. In particular, we analyze how a business-as-usual policy choice (carbon tax equal to specific SCC) and the optimal policy (carbon tax above specific SCC) affect technology deployment and resulting CO_2 emissions.

Intertemporally optimal tax rates of CO_2 emissions are higher than their marginal damages (specific SCC) by the ratio of social (for SCC) to private (for firms' cash flows) discount factors of the respective period. For example, assuming pure rate of time preferences of 1% (social discount rate of 3.81%) for damages from CO_2 emissions and private discount rates of 7% for firms'

[18] 200% SCC yields a wind (solar, nuclear) share of 42.9% (9.6%, 15.7%).

cash flows, yields an (intertemporally) optimal 2050 carbon tax of 257 €/ton, whereas marginal damages, that is, specific SCC, are at 95 €/ton only.

We analyze four taxation choices in detail. The business-as-usual policy choice neglects the difference between private and social discount rates, resulting in a low carbon tax (95 €/ton in 2050) that is insufficient to spur investments into carbon-neutral or carbon-negative technologies. Final CO_2 emissions are at 0.83 Gt. In particular, carbon-capture-and-storage is absent in the technology mix and also nuclear capacity is low. However, wind and solar shares are comparable to those of higher carbon taxes. The optimal carbon tax leads to heavy deployment of gas-CCS, nuclear, and bio-CCS and reduces emissions to –0.15 Gt. A slightly lower carbon tax (188 €/ton in 2050) is already sufficient to reduce carbon emissions to –0.07 Gt. However, reducing the carbon tax even more towards the business-as-usual policy results in substantial positive emissions and fails again to achieve carbon-neutrality targets.

The comparison of outcomes from different taxation choices shows flaws in policy making and explains missing investments into emerging carbon-neutral (gas-CCS, nuclear) or even carbon-negative (bio-CCS) technologies. Announced 2050 carbon prices of 95 €/ton lead to negligible and insufficient emission cutbacks because firms do not evaluate these investments to pay-off in the long-run. However, announcing a carbon price of 257 €/ton delivers the social optimum (as we define it). Electricity prices are highest for the optimal carbon tax (78.5 €/MWh in 2050) but the social cost (or tax) shares are actually lowest because the overall amount of emitted CO_2 is considerably lower in the long-run and even negative in 2050. We further calculate that the optimal carbon tax would reduce accumulated CO_2 emissions by 17 Gt (from 28 Gt in the business-as-usual to 11 Gt) between 2016 and 2050 and saves 1,386 billion € in social cost (255 billion € in discounted terms). On the contrary, the accumulated tax yield would drop by 1,275 billion € (166 billion € in discounted terms).

Our paper demonstrates that the interpretation of modeling results and their consideration by policy makers requires careful review of the assumptions about discount rates, taxes, and what the respective model aims to determine. Some models aim for the social optimum, others depict firm equilibria, and others in turn do not even make any explicit statement thereabout. We model specifications where a social planner tries to set carbon tax rates to push firms to make intertemporally and socially optimal investment and generation decisions. Our first key result that emission tax rates are to be set above marginal damages also underlines that social planners need to consider tax rates or emission prices above marginal damages instead of trying to argue for equality.

Our analysis comes with some limitations. We do not address the time inconsistency problem when re-setting intertemporally optimal tax rates in succeeding periods. To do so, we would need to run the model on a rolling horizon until arriving at 2050. However, effective tax rates from firms' perspectives would remain unchanged. Moreover, the objective of our analysis is to highlight flaws of current modeling when interpreting results and, thus, we refrain from undergoing this computationally intense task. Moreover, we do not account for benefits that arise from using the tax yields of carbon taxation. Those tax yields are indeed highest for the business-as-usual. Finally, our suggested optimal policy might induce distortions across sectors and regions, because

it would lead to higher carbon taxes for sectors with higher private discount rates and lower prices in regions with lower social discount rates.

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Appendix A. Model constraints

Generation constraints. Equations (A.1) to (A.9) contain all constraints that restrict generation (capacity):

$$Y_{ir}(h,v,t) \leq \alpha_{ir}(h,v)\,\beta_{ir}(h,v)\,Q_{ir}(v,t) \quad \forall \quad (i,r,h,v \leq t,t)\,, \tag{A.1}$$

$$Q_{ir}(v,t) \leq q_{ir}^{base}(v)\,\Lambda_i(v,t) \quad \forall \quad \left(i,r,v \leq t^{base},t\right), \tag{A.2}$$

$$Q_{ir}(v,t) \leq IQ_{ir}(v)\,\Lambda_i(v,t) \quad \forall \quad \left(i,r,t^{base} < v \leq t,t\right), \tag{A.3}$$

$$Q_{ir}(v,t) \geq Q_{ir}(v,t+1) \quad \forall \quad \left(i,r,v \leq t,t < t^{end}\right), \tag{A.4}$$

$$\sum_{v \leq t} Q_{ir}(v) \leq iq_{ir}^{lim}(t) \quad \forall \quad (i,r,t)\,, \tag{A.5}$$

$$IQ_{ir}(v) \geq iq_{ir}^{pipe}(t) \quad \forall \quad \left(i,r,t^{base} < v \leq t,t\right), \tag{A.6}$$

$$\sum_{\mu_i(class)} \sum_{v \leq t} Q_{ir}(v,t) \leq q_{ir}^{lim}(class) \quad \forall \quad \left(\mu_{irnw(i)}(class),r,t\right), \tag{A.7}$$

$$\sum_{bio(i)} \sum_{h,v \leq t} \frac{Y_{ir}(h,v,t)}{\eta_{ir}(v)} \leq bc_r^{lim}(t) \quad \forall \quad (r,t)\,, \tag{A.8}$$

$$\sum_{ccs(i)} \sum_{h,v,t} \epsilon_{ir}^{CCS}(v)\,Y_{ir}(h,v,t) \leq sc_r^{lim} \quad \forall \quad (r)\,. \tag{A.9}$$

Equation (A.1) is the *capacity constraint* that restricts generation by available capacity. α is the hourly availability parameter for intermittent renewable energies. Denote by $irnw(i)$ the subset of intermittent renewable energies. In particular, we consider hydro, wind onshore, wind offshore, and solar PV. β is the hourly availability parameter for all other technologies that is calculated out of monthly generation patterns and assumptions about the reliability of the respective technologies. In particular, we consider bioenergy, bio-CCS, gas-OCGT, gas-CCGT, gas-ST, gas-CCS, coal, coal-CCS, lignite, oil, nuclear, and geothermal. For example, when nuclear generation shuts down in summer due to lower load and hot rivers (that prevent cooling of nuclear power plants) then $\beta < 1$. We have $\alpha_{irnw(i),r}(h,v) \in [0,1]$ depending on the hourly availability and technological progress of the respective technology, $\beta_{irnw(i),r}(h,v) = 1$, $\alpha_{\text{not } irnw(i),r}(h,v) = 1$, and $\beta_{\text{not } irnw(i),r}(h,v) \in [0,1]$ depending on monthly availability and technological progress of the respective technology.

Equations (A.2) and (A.3) are the *capacity stock constraints* that describe the movement of capacity over time. $\Lambda \in [0,1]$ is the exogenous lifetime parameter that tells us how much of capacity added in period v is still active in period t. In particular, $\Lambda = 0$ indicates that the entire capacity is inactive. Equation (A.2) refers to existing capacities q^{base} that are still active at the beginning of the planning horizon (from t^{base} to t^{end}). Equation (A.3) in turn explains the movement of added capacity. We allow for endogenous decommissioning of capacities from $t^{base}+1$ onward. For parsimony, we relinquish to show the respective constraints here that avoid early decommissioning of existing capacities in t^{base} already. We assume that the entire investment

is capable of reaching the end of the specified lifetime. Half of the investment is still active 5 years later, and 30% is active even 10 years later. 15 years later none of the past investments are still active. For existing capacities, we assume $\Lambda\left(t^{base}\right), \Lambda\left(t^{base}+1\right) = 1$ to avoid distortions from enforced decommissioning although those existing capacities are still active in reality. We apply the 50% or 30% metric with one period lag, i.e., for $t^{base}+2$ and $t^{base}+3$. Equation (A.4) is the *monotonicity constraint* that enforces monotonic decommissioning of capacity. In particular, once capacity is decommissioned (enforced by the two capacity stock constraints (A.2) and (A.3)) the model should not be able to build them up again. This is particular important when some capacities cause only cost in early periods but have benefits later. Note that this constraint is not restrictive (and also not active) in the last optimization period t^{end}.

Equation (A.5) is the *capacity limit constraint* that enforces that overall capacity does not exceed a certain level, e.g., due to political decisions of not installing further nuclear capacity. Equation (A.6) is the *pipeline constraint* that enforces investments that are already planned or under construction but not commissioned yet. This constraint is particular important in $t^{base}+1 =$ 2020 for wind and solar investments but also in later periods when it is about ongoing nuclear projects. We work with an adapted 2015 calibration that already contains lots of investments until the end of 2020 that are enforced in the model by this pipeline constraint. Equation (A.7) restricts expansion of intermittent renewable energies according to their resource potential by quality class (*resource potential constraint*). In particular, we consider three classes (high, mid, low) of wind onshore, wind offshore, and solar PV potential. $\mu_i\left(class\right)$ is the mapping of the respective intermittent technology to its class. $q_{ir}^{lim}\left(class\right)$ is then the upper limit of the respective quality class (GW). Equation (A.8) is the *biomass constraint*. $bio\left(i\right)$ is the subset of technologies using biomass and η the burning efficiency of the respective technology. $\sum_{bio(i)}\sum_{h,v\leq t}\frac{1}{\eta_{ir}(v)}Y_{ir}\left(h,v,t\right)$ is used biomass and $bc_r^{lim}\left(t\right)$ the annual limit (both in GWh thermal). The underlying assumption of that region-specific constraint is that biomass is not traded across regions. Finally, equation (A.9) is the *carbon-capture-and-storage constraint*. $ccs(i)$ is the subset of carbon-capture-and-storage (CCS) technologies, ϵ^{CCS} the capture rate (ton/GWh electric), and sc_r^{lim} is the region-specific potential of storing carbon in the ground (ton).

Storage constraints. Equations (A.10) to (A.18) contain all constraints that restrict storage (capacity):

$$GC_{jr}(h,v,t) \leq GQ_{jr}(v,t) \quad \forall \quad (j,r,h,v \leq t,t), \tag{A.10}$$

$$GD_{jr}(h,v,t) \leq GQ_{jr}(v,t) \quad \forall \quad (j,r,h,v \leq t,t), \tag{A.11}$$

$$GB_{jr}(h,v,t) \leq GQ_{jr}(v,t) \cdot ghours_{jr}(v) \quad \forall \quad (j,r,h,v \leq t,t), \tag{A.12}$$

$$\begin{aligned} GB_{jr}(h,v,t) &= GB_{jr}(h-1,v,t)\,\eta^{gb}_{jr}(v) \\ &+GC_{jr}(h,v,t)\,\eta^{gc}_{jr}(v) - GD_{jr}(h,v,t) \quad \forall \quad (j,r,h,v \leq t,t), \end{aligned} \tag{A.13}$$

$$GQ_{jr}(v,t) \leq gq^{base}_{jr}(v)\,\Lambda_j(v,t) \quad \forall \quad \left(j,r,v \leq t^{base},t\right), \tag{A.14}$$

$$GQ_{jr}(v,t) \leq GIQ_{jr}(v)\,\Lambda_j(v,t) \quad \forall \quad \left(j,r,t^{base} < v \leq t,t\right), \tag{A.15}$$

$$GQ_{jr}(v,t) \geq GQ_{jr}(v,t+1) \quad \forall \quad \left(j,r,v \leq t, t < t^{end}\right), \tag{A.16}$$

$$\sum_{v \leq t} GIQ_{jr}(v) \leq gq^{lim}_{jr}(t) \quad \forall \quad (j,r,t), \tag{A.17}$$

$$GIQ_{jr}(v) \geq giq^{pipe}_{jr}(t) \quad \forall \quad (j,r,v=t). \tag{A.18}$$

Equations (A.10) and (A.11) are the *charge* and *discharge constraint*. Equation (A.12) is the *size constraint* that restricts the storage balance to the maximum size of the storage. Equation (A.13) is the *balance constraint* that explains the evolution of stored energy over time. η^{gb} hourly efficiency reflecting the hourly loss of stored energy (e.g., evaporation) and η^{gc} is the charging efficiency (e.g., electricity necessary to use pumps) that accounts for the fact that taking one unit of electricity from the market leads to less than one unit of electricity in the storage. The storage discharge is subject to losses as well but those are not depicted but rather in the demand-equals-supply constraint (1). Equations (A.14) and (A.15) are the *capacity stock constraints*, Equation (A.16) is the *monotonicity constraint*, Equation (A.17) the *capacity limit constraint*, and Equation (A.18) the *pipeline constraint* that mirror equations (A.2) to (A.6) from the set of generation constraints. Here, gq^{base} are capacities already active in t^{base} (in GW) and gq^{lim}, giq^{pipe} (in GW) the respective upper and lower limits of expanding overall capacity or adding capacity, respectively.

Transmission constraints. Equations (A.19) to (A.24) contain all constrains that restrict transmission (capacity):

$$E_{k,r-rr}(h,t) \leq \sum_{v \leq t} TQ_{k,r-rr}(v,t) \quad \forall \quad (\mu_{k,r-rr}, h, t), \tag{A.19}$$

$$TQ_{k,r-rr}(v,t) \leq tq^{base}_{k,r-rr}(v)\,\Lambda_k(v,t) \quad \forall \quad \left(\mu_{k,r-rr}, v \leq t^{base}, t\right), \tag{A.20}$$

$$TQ_{k,r-rr}(v,t) \leq TIQ_{k,r-rr}(v)\,\Lambda_k(v,t) \quad \forall \quad \left(\mu_{k,r-rr}, t^{base} < v \leq t, t\right), \tag{A.21}$$

$$TQ_{k,r-rr}(v,t) \geq TQ_{k,r-rr}(v,t+1) \quad \forall \quad \left(\mu_{k,r-rr}, v \leq t, t < t^{end}\right), \tag{A.22}$$

$$\sum_{rr,v \leq t} TIQ_{k,r-rr}(v) \leq tq^{lim}_{k,r-rr}(t) \quad \forall \quad (\mu_{k,r-rr}, t), \tag{A.23}$$

$$TIQ_{k,r-rr}(v) \geq tiq^{pipe}_{k,r-rr}(t) \quad \forall \quad (\mu_{k,r-rr}, v \leq t, t). \tag{A.24}$$

Equation (A.19) is the trade constraint that restricts the bilateral trade between a region pair $r - rr$ to the overall amount of transmission capacity between that region pair. We do not differentiate trade flows by vintages because technology characteristics are assumed to be the same for each vintage. Equations (A.20) and (A.21) are the *capacity stock constraints*, Equation (A.22) is the *monotonicity constraints*, Equation (A.23) is the *limit constraint*, and Equation (A.24) is the *pipeline constraint*. $tq^{base}_{k,r-rr}$ is the existing transmission capacity of technology k between a region pair $r-rr$, tq^{lim} the upper limit of possible transmission expansion, and tiq^{pipe} ongoing transmission projects (all in GW). In particular, tq^{lim} grows over time to account for the political will to increase interchange in Europe but still limits expansion to a socially acceptable amount. tiq^{pipe} is mainly in line with the plans of transmission system operators to reach a 25% interconnectivity target and contains already planned projects. Those two constraints are fundamentally more important for transmission than the matches for generation and storage operations.

Appendix B. Annual electricity demand and fuel prices

Table B.1: Annual electricity demand (TWh)

	2015	2020	2025	2030	2035	2040	2045	2050
Austria	63	64	78	91	137	147	156	163
Belgium	83	82	96	107	131	157	181	196
Bulgaria	30	30	35	36	37	39	41	43
Croatia	16	16	17	18	18	20	23	25
Czech Republic	59	63	116	121	125	133	141	149
Denmark	32	32	37	35	39	47	52	56
Estonia	7	8	9	11	12	12	13	14
Finland	80	73	83	79	80	82	87	91
France	448	450	759	768	813	868	926	986
Germany	528	534	832	843	843	874	910	950
Greece	52	53	58	54	58	63	68	71
Hungary	38	37	44	53	67	71	75	81
Ireland	26	26	31	32	39	42	45	49
Italy	297	319	421	562	597	644	689	735
Latvia	6	7	8	9	10	12	12	13
Lithuania	10	12	18	18	17	18	19	20
Luxembourg	6	6	7	8	11	14	15	17
Netherlands	109	113	148	186	189	199	210	226
Norway	119	124	131	126	158	168	179	190
Poland	139	143	164	179	229	267	280	293
Portugal	47	52	61	62	66	70	73	76
Romania	47	47	54	58	60	67	74	80
Slovak Republic	25	27	34	39	48	56	58	60
Slovenia	13	13	15	17	19	22	23	24
Spain	239	247	313	367	494	523	543	568
Sweden	128	133	159	161	232	248	265	282
Switzerland	58	61	67	71	117	128	139	151
United Kingdom	311	317	358	389	435	489	533	595

Table B.2: Exemplary fuel prices for Germany (€/MWh thermal)

	2015	2020	2025	2030	2035	2040	2045	2050
Bioenergy	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Coal	8.35	8.22	8.09	7.94	7.79	7.68	7.58	7.49
Lignite	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Gas	20.65	20.34	20.01	19.63	19.27	18.99	18.74	18.53
Oil	40.26	40.84	41.18	41.58	42.14	42.74	43.51	44.34
Uranium	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33

Appendix C. Technology parameters

Table C.3: Efficiencies of generation technologies

	2015	2020	2025	2030	2035	2040	2045	2050
Bioenergy	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23
Bio-CCS	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18
Gas-CCGT, Gas-ST	0.59	0.60	0.61	0.62	0.62	0.62	0.62	0.62
Gas-CCS	0.47	0.48	0.49	0.50	0.50	0.50	0.50	0.50
Gas-OCGT	0.42	0.44	0.45	0.46	0.46	0.47	0.47	0.47
Coal	0.45	0.47	0.48	0.49	0.49	0.49	0.49	0.49
Coal-CCS	0.36	0.37	0.38	0.39	0.39	0.39	0.39	0.39
Lignite*	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Oil*	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	0.09	0.11	0.11	0.12	0.13	0.13	0.14	0.14
Nuclear	0.59	0.60	0.61	0.62	0.62	0.62	0.62	0.62

Values refer to state-of-the-art capacities from the respective vintage. *Lignite and oil values refer to 2015 vintages in the respective period because lignite and oil expansion is forbidden.

Table C.4: Emission factor (ton/GWh electric) of generation technologies

	2015	2020	2025	2030	2035	2040	2045	2050
Bio-CCS	-855	-855	-805	-805	-805	-760	-760	-760
Gas-CCGT, Gas-ST	347	341	335	330	330	330	330	330
Gas-CCS	42	41	40	39	39	39	39	39
Gas-OCGT	507	484	473	463	463	453	453	453
Coal	797	763	747	732	732	732	732	732
Coal-CCS	94	91	89	86	86	86	86	86
Lignite	838	838	838	838	838	838	838	838
Oil	910	910	910	910	910	910	910	910

Values refer to state-of-the-art capacities from the respective vintage. *Lignite and oil values refer to 2015 vintages in the respective period because lignite and oil expansion is forbidden. Bioenergy, geothermal, and nuclear are emission neutral.

Table C.5: Investment cost (€/kW) of generation technologies

	2015	2020	2025	2030	2035	2040	2045	2050
Bioenergy	4,322	4,236	4,149	4,149	4,106	4,063	4,063	4,020
Bio-CCS	6,322	6,236	6,149	6,149	6,106	6,063	6,063	6,020
Gas-CCGT, Gas-ST	850	850	850	850	850	850	850	850
Gas-CCS	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495
Gas-OCGT	437	437	437	437	437	437	437	437
Coal	1,500	1,500	1,440	1,410	1,395	1,380	1,380	1,365
Coal-CCS	3,415	3,415	3,278	3,210	3,176	3,142	3,142	3,108
Lignite*	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Oil*	822	822	822	822	822	822	822	822
Geothermal	12,364	11,993	11,622	11,498	11,251	11,127	11,004	11,004
Nuclear**	7,600	7,006	6,346	6,082	5,818	5,488	5,488	5,356
Solar	1,300	1,027	936	858	819	780	741	715
Wind offshore	3,600	3,024	2,700	2,520	2,376	2,268	2,160	2,088
Wind onshore	1,520	1,397	1,368	1,339	1,325	1,310	1,310	1,296

Values refer to state-of-the-art capacities from the respective vintage. *Lignite and oil values refer to 2015 vintages in the respective period because lignite and oil expansion is forbidden. **Social cost of nuclear are often neglected in energy system analysis, in particular, decommissioning cost and storing nuclear waste. Given cost estimates of around 6,000 €/kW for installing nuclear facilities, estimates are around 1,000 €/kW for decommissioning them. However, the timing of those cost at the very end of the respective life times impedes their appropriate consideration. In fact, a discount rate of 7% leads to the consideration of only 100 €/kW decommissioning cost. We thus opt for an approach, where firms need to pay a decommissioning premium of 1,000 €/kW into a decommissioning fund at time of construction, so that 2020 investment cost are at 7,000 (instead of 6,000) €/kW.

Appendix D. GDP and population projections

Table D.6: GDP projections (billion 2015-€)

	2015	2020	2025	2030	2035	2040	2045	2050
Austria	436	474	511	546	589	636	683	728
Belgium	528	566	606	654	719	797	877	960
Bulgaria	56	62	67	71	75	79	83	86
Croatia	57	62	65	69	75	82	88	94
Czech Republic	204	223	238	258	277	297	317	338
Denmark	346	388	429	463	499	542	590	643
Estonia	26	29	31	33	35	38	40	41
Finland	271	287	303	323	350	382	413	445
France	2,841	3,066	3,270	3,488	3,763	4,094	4,435	4,820
Germany	3,850	4,091	4,328	4,490	4,640	4,855	5,097	5,334
Greece	234	241	246	256	275	295	306	316
Hungary	137	148	165	180	194	207	217	231
Ireland	250	282	306	333	363	393	420	455
Italy	2,132	2,273	2,409	2,556	2,733	2,939	3,144	3,385
Latvia	31	35	39	42	44	47	50	52
Lithuania	47	54	57	58	59	63	67	71
Luxembourg	65	74	84	95	108	123	138	154
Netherlands	876	938	987	1,028	1,083	1,153	1,230	1,317
Norway	507	555	601	654	715	785	861	936
Poland	542	622	698	769	826	881	919	947
Portugal	228	245	266	281	296	309	319	330
Romania	198	222	243	261	278	297	317	338
Slovak Republic	99	114	128	144	156	164	169	173
Slovenia	49	53	58	62	65	70	74	78
Spain	1,376	1,510	1,652	1,793	1,936	2,061	2,141	2,264
Sweden	570	630	697	765	847	937	1,033	1,131
Switzerland	700	776	859	950	1,055	1,172	1,300	1,430
United Kingdom	2,984	3,188	3,366	3,611	3,948	4,354	4,780	5,215
World	78,242	90,573	104,038	119,466	136,834	155,959	175,894	196,762

Table D.7: Population projections (million)

	2015	2020	2025	2030	2035	2040	2045	2050
Austria	8.64	8.92	8.98	9.04	9.07	9.06	9.01	8.93
Belgium	11.27	11.54	11.70	11.83	11.93	12.01	12.06	12.09
Bulgaria	7.18	6.92	6.66	6.38	6.10	5.84	5.59	5.36
Croatia	4.20	4.04	3.93	3.82	3.70	3.56	3.43	3.30
Czech Republic	11	11	11	11	11	11	11	11
Denmark	5.68	5.83	5.94	6.03	6.10	6.17	6.21	6.25
Estonia	1.32	1.33	1.30	1.27	1.24	1.21	1.18	1.15
Finland	5.48	5.53	5.56	5.55	5.52	5.50	5.48	5.45
France	66.55	67.20	68.01	68.54	68.87	69.09	69.18	69.09
Germany	81.69	83.15	82.55	82.22	81.72	80.93	79.80	78.53
Greece	10.82	10.66	10.38	10.15	9.93	9.71	9.48	9.20
Hungary	9.84	9.74	9.58	9.40	9.18	8.94	8.73	8.52
Ireland	4.70	4.98	5.14	5.27	5.38	5.50	5.60	5.68
Italy	60.73	60.18	59.51	58.59	57.64	56.62	55.29	53.59
Latvia	1.98	1.89	1.81	1.73	1.66	1.60	1.55	1.50
Lithuania	2.90	2.76	2.64	2.54	2.44	2.35	2.26	2.18
Luxembourg	0.57	0.63	0.66	0.69	0.72	0.74	0.76	0.78
Netherlands	16.94	17.38	17.55	17.65	17.67	17.61	17.48	17.29
Norway	5.19	5.39	5.62	5.83	6.03	6.21	6.37	6.52
Poland	37.99	37.91	37.57	36.95	36.09	35.09	34.12	33.19
Portugal	10.36	10.25	10.11	9.95	9.77	9.57	9.34	9.08
Romania	19.82	19.25	18.82	18.35	17.84	17.31	16.82	16.30
Slovak Republic	5.42	5.46	5.44	5.39	5.30	5.19	5.07	4.96
Slovenia	2.06	2.09	2.08	2.06	2.03	2.00	1.97	1.93
Spain	46.44	47.13	46.87	46.46	45.93	45.30	44.51	43.49
Sweden	9.80	10.34	10.61	10.83	11.01	11.19	11.38	11.55
Switzerland	8.28	8.63	8.90	9.13	9.32	9.47	9.59	9.68
United Kingdom	65.12	67.16	68.44	69.54	70.48	71.36	72.13	72.74
World	7,339	7,754	8,140	8,501	8,836	9,145	9,426	9,676

Appendix E. Technology-specific social cost and optimal tax

Table E.8: Optimal carbon tax (€/MWh electric) of generation technologies for different social discount rates

		2020	2030	2040	2050
Low (BAU)	Bio-CCS	-35.67	-44.79	-56.49	-70.92
	Coal	31.13	38.82	50.93	66.41
	Coal-CCS	3.89	5.09	6.68	8.72
	Gas-CCGT, Gas-ST	14.32	18.13	23.79	31.02
	Gas-CCS	1.75	2.29	3.00	3.91
	Gas-OCGT	19.74	24.74	31.77	41.42
	Lignite*	35.70	46.71	61.29	79.91
	Oil*	38.76	50.70	66.53	86.75
Medium	Bio-CCS	-36.83	-51.67	-72.83	-102.15
	Coal	32.14	44.78	65.66	95.66
	Coal-CCS	4.02	5.88	8.62	12.55
	Gas-CCGT, Gas-ST	14.78	20.91	30.66	44.67
	Gas-CCS	1.80	2.64	3.87	5.63
	Gas-OCGT	20.38	28.54	40.95	59.66
	Lignite*	36.86	53.88	79.00	115.10
	Oil*	40.01	58.49	85.76	124.95
High	Bio-CCS	-37.86	-58.40	-90.51	-139.60
	Coal	33.04	50.61	81.60	130.73
	Coal-CCS	4.13	6.64	10.71	17.16
	Gas-CCGT, Gas-ST	15.19	23.64	38.11	61.05
	Gas-CCS	1.85	2.98	4.81	7.70
	Gas-OCGT	20.95	32.26	50.89	81.53
	Lignite*	37.89	60.90	98.19	157.30
	Oil*	41.13	66.11	106.59	170.76
Optimal	Bio-CCS	-38.93	-66.10	-112.75	-191.39
	Coal	33.97	57.29	101.65	179.23
	Coal-CCS	4.25	7.52	13.34	23.52
	Gas-CCGT, Gas-ST	15.63	26.75	47.47	83.70
	Gas-CCS	1.91	3.37	5.99	10.55
	Gas-OCGT	21.54	36.51	63.40	111.78
	Lignite*	38.96	68.93	122.31	215.66
	Oil*	42.30	74.82	132.77	234.11

The private discount rate is at 7%. Values refer to state-of-the-art capacities from the respective vintage. *Lignite and oil values refer to 2015 vintages in the respective period because lignite and oil expansion is forbidden. Bioenergy, geothermal, and nuclear are emission neutral and those not subject to taxation.

Appendix F. Sensitivity analysis

Figure F.1: Generation mix and carbon emissions for different SCC levels

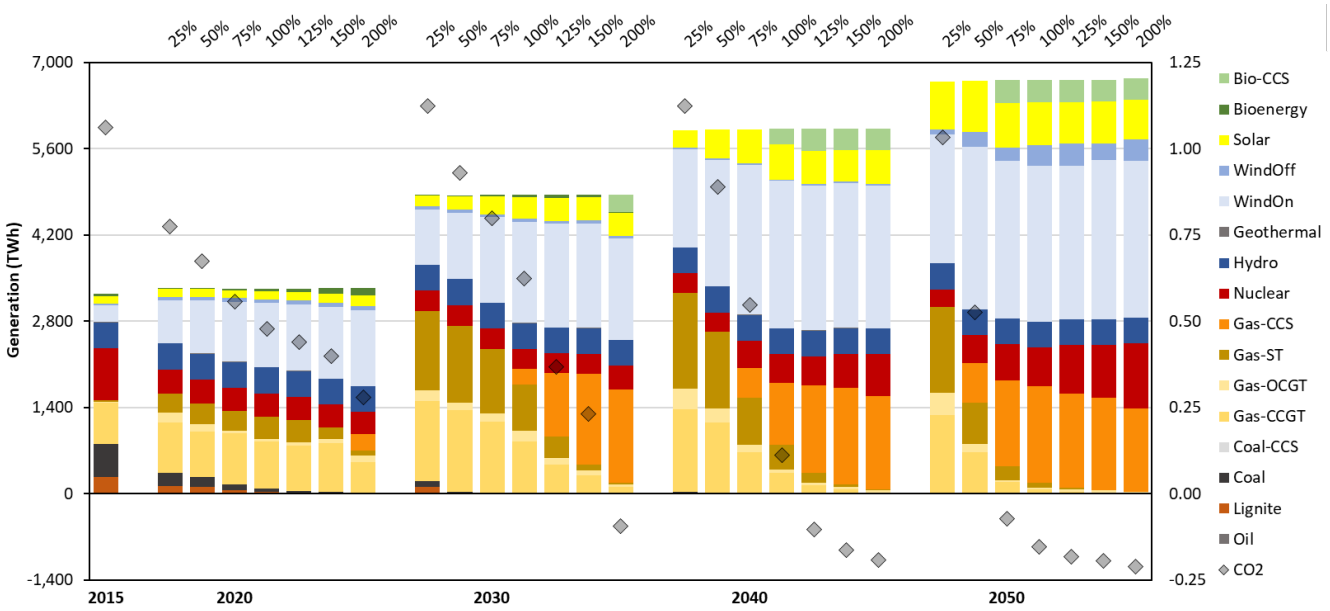

Table F.9: Accumulated carbon emissions, SCC, and tax amounts with price ranges from period 2020 to 2050 for different SCC levels

SCC level	CO_2 (Gt)	SCC (*) (billion €)	Tax (billion €)	Electricity price (€/MWh) Total	Tax
25%	37.2	622 (186)	1,214	54.8–67.0 (67.0, 2050)	2.9–10.7 (10.7, 2050)
50%	28.4	918 (297)	1,718	57.6–74.9 (77.5, 2045)	5.1–10.9 (13.0, 2045)
75%	18.3	789 (325)	1,253	60.2–76.0 (77.6, 2035)	6.3–(–2.3) (12.4, 2035)
100%	10.8	532 (389)	643	63.1–78.5 (78.6, 2035)	7.2–(–6.4) (11.4, 2030)
125%	5.4	240 (231)	67	66.2–79.9 (79.9, 2045)	8.3–(–9.5) (10.2, 2025)
150%	1.5	-57 (146)	-485	70.2–81.1 (81.8, 2045)	9.0–(–12.1) (9.0, 2020)
200%	-2.1	-465 (17)	-1,237	75.8–82.8 (83.9, 2045)	8.4–(–17.5) (8.4, 2020)

The period 2020 to 2050 covers indeed 35 years because 2020 reflects 2016 to 2020. We spare 2015 to include in this calculation because the outcome from the calibration year are the same for each specification and SCC are not internalized perfectly in this year. *The value in brackets refers to discounted SCC. Electricity price (total, tax share) ranges are from 2020 to 2050 with the maximum value and the corresponding year in brackets.