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Abstract

Bottom-up optimization models neglect the inclusion of investment behavior We introduce three investor types that differ in their investment cost specifications, financing costs, and discounting. This leads to a substantially different pace and rate of adoption for specific generation technologies. For the European power market, 2050 wind (nuclear, gas-CCS) capacity ranges from 624 to 1,113 GW (84 to 194 GW, 383 to 502 GW), depending on the respective investor type. Accounting for type heterogeneity leads to 2050 wind (nuclear, gas-CCS) capacity of 912 GW (140 GW, 428 GW). Technology-specific financing cost increase 2050 wind (nuclear, gas-CCS) capacity even to 1,069 GW (80 GW, 449 GW). Hence, our results confirm that accounting for more differentiated picture of electricity market investment with heterogeneous investor types can provide a starting point for tailor-made energy policies, thereby increasing the efficiency and effectiveness of public policies fostering the decarbonization of power markets.

JEL code: C61, C68, Q40, Q41
Keywords: Investment behavior, investor type, investment cost, bottom-up optimization model, energy system model, power market model

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1. Introduction

Detailed numerical bottom-up models are widely used as tools of analysis to provide robust policy recommendations. Those models run different scenarios to advice decision makers in the energy and power sector by informing about the role of climate change and assessing the impact of potential changes in environmental policies (Cao et al., 2016). Modeling the temporal as well as spatial resolution, technology details, and economic behavior are some of the major future challenges facing detailed numerical energy system and power market models (Pfenninger et al., 2014). Some models are already able to depict complete hourly resolution of the year when applying a myopic approach (Poncelet et al., 2016, e.g.,). Others have flexible spatial resolution below country-level scope which can be adjusted in line with the research question (Martínez-Gordón et al., 2021, e.g.,). Others have fundamental technology richness and depict, for example, additional technological characteristics of storage such as maximum cycles and power plants like ramping constraints (e.g., Ringkjøb et al., 2018).

However, those improvements only bring the models moderately closer when depicting reality while also driving them even further apart from each other. At the same time, one crucial driver of models' outcomes—*economic behavior* of firms and investors, is not covered in these advancements. We address this gap in the existing research by elaborating on the role of economic behavior in detailed power market models. In this regard, we evaluate the impact of *investor type heterogeneity* by means of diverging investment cost specifications, financing cost, and discounting.

The key determinants of investment behavior are usually attributed to firm-, market-, and project-specific characteristics (Groot et al., 2013). Starting with firm-specific drivers, investment behavior differs for stock market listed, privately held, and public firms. Those firms differ in their investment magnitudes, reaction to changes in investment opportunities, financing costs, and their way of discounting future cost and benefits from investments. Stock market listed firms tend to invest considerably less and are not as responsive to changes in investment opportunities, especially in industries in which stock prices are quite sensitive to earnings news (Asker et al., 2011). Public firms focus more on long-term projects, tolerate investments with higher levels of uncertainty, have better access to equity capital because the state as (predominant) owner can withhold profits and provide additional funding when necessary (Groot et al., 2013). Furthermore, market specific drivers such as the degree of competition and underlying ownership structures determine investment behavior, the types of firms active in a specific market, and vice versa. The lack of attention to market-specific conditions in power market models dates back to the early 1950s, where the optimization problem was limited to the capacity expansion of a vertically integrated and heavily regulated monopoly (Foley et al., 2010). The liberalization of power markets in the United States and Europe heralded the end of an era of monopolies and opened the markets for new players leading to diverging degrees of competition and various combinations of firms with varying ownership structures. For instance, private investors and renewable-energy funds entered the markets when renewables had started to play an important role (e.g. Hirth and Steckel, 2016).[1]

[1]Marti-Ballester (2020) suggest that renewable-energy fund investors are less sensitive to past financial perfor-

Finally, technology-specific drivers cover irreversibility of investments as well as technological and regulatory uncertainty (Groot et al., 2013). Irreversibility is higher for conventional power plants and political support to expand renewables contributes to reducing regulatory uncertainty and thus also financing cost for renewables projects. Moreover, renewable power plants are perceived to be less technologically demanding. Additionally, a varying discount rate is often applied by investors when assessing conventional and renewables investments (Steffen, 2020). The key determinants of investment behavior also interact with each other and can partly induce themselves. For example, new players on power markets tend to be stock market listed or privately held firms with higher shares of renewable energies compared to conventional technologies.[2] However, existing models fully neglect the existence of those drivers and instead apply an averaged "representative" investor operating in an averaged market environment (Tash et al., 2019).

In this paper, we advance a more differentiated picture of power market investment by developing a theoretical framework to model investor type heterogeneity and testing in with the EUREGEN model—a European power market partial equilibrium model that optimizes investments, decommissioning, and dispatch for generation, storage, and transmission technologies intertemporally until 2050—allowing to quantify the impact of investor type heterogeneity on capacity expansion, generation mix, and CO_2 emissions.[3] Three different investment cost specifications reflect three types of investors, which can be observed on the majority of power markets including utilities, social planners, and private or institutional investors.

Normal investors apply an investment cost specification that carries the burden of investments in the period of investment (e.g., Weissbart and Blanford, 2019). Such a behavior bests reflects public firms or heavily regulated (by a social planner) monopolies. *Capital cost investors* represent big institutional investors and funds, that only pay for bound capital which is a mix of own and debt capitals (e.g., Bachner et al., 2019). In turn, repayment is of little consequence for this type of investor, since capital cost investors can refinance themselves by own revenues or new debt capital. Repayment, in turn, matters for the *annuity investors*, who are intended to match smaller and private firms' and investors' behaviors. The underlying assumptions—albeit often not clearly stated in model documentations—is that investment is 100% financed by debt capital and the annuity is a constant charge that has to be paid every year over the payback time of the investment including repayment and interest (e.g., Gerbaulet and Lorenz, 2017, Hess et al., 2018). We additionally change discount and interest rates for normal, capital cost, and annuity investors. The normal investor faces lowest discount rates because of the long-run orientation of public firms and lowest interest rates because the state as owner reduces financing cost. The annuity investor then faces highest discount and interest rates. Additionally, we apply technology-specific mark-ups

mance than are classic utilities or conventional fund investors because renewable-energy fund investors derive parts of their utility from non-financial attributes.

[2]In 2016, 86% of conventional power generation capacity is owned by the four biggest utilities in Germany, whereas they own 17% of renewables generation capacity.

[3]See Weissbart and Blanford (2019) for the underlying basics of the EUREGEN model and Weissbart (2020), Mier and Weissbart (2020), Mier et al. (2020), Siala et al. (2020), Azarova and Mier (2020) for applications.

on interest rates to reflect irreversibility as well as varying degree of technological and regulatory uncertainty of conventional and renewables projects.

We start by highlighting the impact of the three investment cost specifications under the assumption of same interest and discount rates for each investor type. The normal investor invests earlier and less later. In turn, the capital cost investor closes the gap to the normal investor over time. The annuity investor invests the least and the gap to the others stays persistent even in long-term horizon. The normal investor increasingly invests when neglecting discounting, whereas no discounting hampers investments for capital cost and annuity investors. Differences are also far smaller for capital cost and annuity investors compared to the discounting case. Next, we vary discount and interest rates for each investor type. For the normal investor, lower interest rates lead to more short-term investments. In the long-run total capacity is smaller because nuclear expansion is fostered by low interest and discount rates. The pattern completely turns for the capital cost investor. Very low discount and interest rates lead to increasingly investments over the entire time horizon. The annuity investor, in turn, is very insensitive towards changes in interest and discount rates. Finally, we apply type- and technology-specific interest and discounts rates and combine the three investors within the model to account for investor type heterogeneity on markets. The differences between the types increase when applying type-specific rates (normal investor faces lowest rates, annuity investor highest). Assuming equal shares of investors in turn gives a robust projection for the long-run equilibrium of the European power market. However, technology-specific interest rates impact results more than type-specific interest rates when accounting for investor type heterogeneity.

In this paper, we examine how integrating investment behavior and investor type heterogeneity within one model framework affects the outcome of bottom-up optimization models. To do so, we discuss theoretical and empirical evidence for determinants of investment decisions in Section 2. Section 3 describes theoretical foundations of the modeling strategy. Section 4 provides illustrative examples for the different investment cost specifications of each investor type and Section 5 gives on overview about the most important underlying data. Section 6 presents results and Section 7 concludes.

2. Literature

Explaining and predicting investment behavior has long been the focus of economic studies, starting in 1920s with a rather simplistic and criticized accelerator theory according to which investments are triggered by increasing growth in demand (Hochstein, 2018). Jorgenson (1967) explains the determinants of investment behavior based on the neoclassical theory of optimal capital accumulation and key assumption of firm's present value maximization. He defines the appropriate cost of capital for investment decisions as the weighted average of the expected return to equity and return to debt. Thereby, the cost of capital and investment decision are assumed to be independent of the financial structure of the firm or of its dividend policy. This contradicts the cost of capital as defined in the liquidity theory of investment behavior (Meyer and Kuh, 1955, Jorgenson et al., 1970). Other studies suggest alternative theories and doubt that firms should be aiming to maximize the present value instead of profits (Hannan, 1982, Olsen, 1977). Other studies forward real option theory (Arrow and Fisher, 1974, Gollier et al., 2005) which advances importance of timing (investment postponement option) and flexibility, refraining from "now or never" investment decisions as is the case with prior theories, and introducing risk and uncertainty considerations (Kozlova, 2017, Black and Scholes, 1973). The real option theory is frequently applied in the context of investments in generation capacity and renewable energy investments specifically (e.g. Reuter et al., 2012).

These theories, among others, have been tested and proven (or proven wrong) by a plethora of empirical works (Farla, 2014) aiming to explain investment behaviour and decision-making of different actors from variety of sectors and industries (e.g. Jorgenson, 1971, Jorgenson et al., 1970, Guussen and Opschoor, 1995, Cummins et al., 2006, Lioukas, 1983), countries (e.g. Feldstein and Flemming, 1971, Gedajlovic et al., 2005, Meinen and Röhe, 2017, Döring et al., 2021), and policy setups including the impact of feed-in tariffs, investment subsidies, taxation schemes as well as credits, and certificate systems (e.g. Zwick and Mahon, 2017, Hassett and Metcalf, 1999, Taubman and Wales, 1969). Yet, neither theoretical nor empirical studies are unanimous on the key determinants of investment behavior and generally accepted standard model of investment does not seem to have developed yet(Broer and Van Leeuwen, 1994).

Nonetheless, reported results of these studies have a common denominator; namely, they all confirm complexity and heterogeneity of investment behavior. In turn, this implies that relying on a "representative agent" acting fully rational in an averaged "representative" market is most likely to be unfeasible. Hence, integrating a more detailed representation of investment decision-making in bottom-up optimization models such as power market or energy system models reflecting this heterogeneity is essential for unbiased model-based recommendations.

Growing attention has been devoted to detailed modeling of technical aspects (Ventosa et al., 2005) including generation technologies and representation of the grid in parallel with a more sophisticated representation of hourly time series and storage (Lopion et al., 2018). Investment specifics have not yet been the major focus in the modeling community. This could be due to complexity and absence of agreement or dominant theory explaining investment behavior. Nonetheless, some efforts to reflect the underlying investor heterogeneity have already been suggested in a few models. For instance, Hirth and Steckel (2016) use the EMMA model to show that increasing the capital cost encourages use of fossil fuels and can be harmful for renewable generation technologies. They model capital cost by applying the weighted average cost of capital (WACC). This approach matches our capital cost investor. Our findings corroborate their results in the short run. When investments are more expensive, there are less investments in renewable capacity.

However, we show that when CO_2 prices are high enough fossil fuels are mainly phased out even for higher capital cost, although overall decarbonization and renewables shares are lower. Tash et al. (2019) introduce a desegregation of investors in the TIMES Actors model through a varying hurdle rate by technology and actor. The model reflects three actors including utilities, institutional investors, and citizens. They suggest additional budget constraints in the form of capacity limits. However, they application of their approach is limited only to wind and solar technologies on the German electricity market. Lemming and Meibom (2003) introduce an iterative interaction of a separate risk-adjustment model with a partial equilibrium model. Implementation is limited to representation of risk aversion and uncertainty. Technically it is a separate module that interacts with the model. The authors suggest to integrate it directly. However, they refrain from doing so due to possible non-linearities. While these studies do not fully account for investment behavior and investor type heterogeneity, they open an important avenue in energy system and power market modeling and underline the importance of representing investment behavior in detail. In this paper we advance these efforts both in scope (introducing heterogeneity of investor types in European power market without technological constraints) and technical implementation (by introducing this directly in the model through investment cost specification).

3. Modeling Strategy

Consider technologies j (e.g., wind onshore), regions r (e.g., Germany), time periods $t = 2015, 2020, ..., 2050$, and the period of installation $v = 1960, 1965, ..., 2050$. We use subscript j, r to denote variables and parameters and parentheses for periods v, t, i.e., $Q_{jr}(v)$ is the capacity installed in period v and $C_{jr}(v)$ the constant unit cost. The discount factor δ follows from the discount rate ν and reflects that each period $t \geq 2020$ accounts for $t_{step} = 5$ years, i.e.,

$$\delta(t) = \frac{(1+\nu)^{t_{step}} - 1}{\nu(1+\nu)^{t-t_{base}}}, \tag{1}$$

where $t_{base} = 2015$ serves as focal point.[4]

Normal investor. The *normal* investor considers all investment cost in the period of installation v. The objective is thus given by

$$\min_{\mathbf{Q},...} \; \textstyle\sum_t \frac{\delta(t)}{t_{step}} \sum_r \left[\displaystyle\sum_j \sum_{v=t} Q_{jr}(v)\, C_{jr}(v) \times \Gamma_{jr}(v,t) + ... \right], \tag{2}$$

where $\mathbf{Q}$ is the vector of investment decisions. Observe that δ already reflects the number of years within one period, that is, for investments we need to divide by t_{step}. $Q_{jr}(v)\, C_{jr}(v)$ are direct cost of investing into a technology and Γ is the endeffect. This reflects that the depreciation time of an investment might expand beyond the model horizon, i.e.,

$$\Gamma_{jr}(v,t) = \frac{\sum_t \gamma(t)\, \Lambda_{ir}(v,t)}{\sum_{t_{long}} \gamma(t_{long})\, \Lambda_{ir}(v, t_{long})}. \tag{3}$$

[4]2020 reflects the time period 2016 to 2020, 2025 reflects 2021 to 2025, ...

$t_{long} = 2015, \ldots$ reflects an unconstrained time horizon to allow for full depreciation of every investment. Λ is a binary parameter that takes the value 1 when the investment is still under depreciation and 0 otherwise, i.e.,

$$\Lambda_{jr}(v,t) = \begin{cases} 1 & \text{if } t \leq v + t_{jr,depr}(v) \\ 0 & \text{if } t > v + t_{jr,depr}(v) \end{cases}, \tag{4}$$

where $t_{jr,depr}(v)$ is the depreciation time of an investment.[5] Finally, $\gamma(t)$ is the interest factor that reflects the discount factor by using the interest rate i, i.e.,

$$\gamma(t) = \frac{(1+i)^{t_{step}} - 1}{i(1+i)^{t-t_{base}}}. \tag{5}$$

Annuity investor. The *annuity* investor assumes that an investment is financed by debt capital only. The annuity reflects interests and repayment, i.e.,

$$A_{jr}(v) = \frac{i(1+i)^{t_{jr,depr}(v)}}{(1+i)} - 1. \tag{6}$$

Investments cause a stream of cost over the entire deprecation time of the respective investment. The underlying objective becomes:

$$\min_{\mathbf{Q},\ldots} \quad \textstyle\sum_t \delta(t) \sum_r \quad \left[\displaystyle\sum_j \sum_{v \leq t} Q_{jr}(v)\, C_{jr}(v) \times \mathit{\Lambda}_{jr}(v,t)\, A_{jr}(v) + \ldots \right]. \tag{7}$$

Observe that cash flows are still subject to discounting but are no longer divided by t_{step} because annuities have to be paid on an annual basis.

Capital cost investor.. The *capital cost* investor assumes that a capital stock is subject to capital cost, best reflected by the weighted average cost of capital $WACC$. For parsimony, we assume that $WACC = i$. The difference to the annuity approach is thus that the depreciation time of an investment does affect the annual cost, so the objective is:

[5]The installation period v reflects potential technological progress with respect to lifetime and also depreciation time. It might also reflect a changing investor behaviour.

$$\min_{\mathbf{Q},\ldots} \quad \sum_t \delta(t) \sum_r \quad \left[\sum_j \sum_{v \le t} Q_{jr}(v)\, C_{jr}(v) \times \mathit{\Lambda}_{jr}(v,t)\, WACC + \ldots \right]. \tag{8}$$

Investor type heterogeneity. Suppose that $type = nor, ann, cap$ denote normal, annuity, and capital cost investors. ς_{type} is the share of an investor type with $\sum_{type} \varsigma_{type} = 1$. Indicate by ν_{type}, i_{type} type-specific discount and interest rates. We obtain a weighted discount (interest) rate from $\nu_{weight} = \sum_{type} \varsigma_{type} \nu_{type}$ $(i_{weight} = \sum_{type} \varsigma_{type} i_{type})$.[6] The respective discount factor δ_{weight} and interest factor γ_{weight} calculate according to (1) or (5), respectively. The annuity follows from (6) by using $i = i_{cap}$ and we have $WACC = i_{cap}$. The cost minimization problem now contains all three investor types, i.e.,

$$\begin{aligned} \min_{\mathbf{Q},\ldots} \quad \sum_t \delta_{weight}(t) \sum_r [\quad & \varsigma_{nor} \sum_j \sum_{v=t} Q_{jr}(v)\, C_{jr}(v) \times \Gamma_{jr}(v,t) \frac{1}{t_{step}} + \\ & \varsigma_{ann} \sum_j \sum_{v \le t} Q_{jr}(v)\, C_{jr}(v) \times \mathit{\Lambda}_{jr}(v,t)\, A_{jr}(v) + \\ & \varsigma_{cap} \sum_j \sum_{v \le t} Q_{ir}(v)\, C_{jr}(v) \times \mathit{\Lambda}_{jr}(v,t)\, WACC + \ldots]. \end{aligned} \tag{9}$$

The first line represents investment cost of normal investors, the second of annuity investor, and the third of capital cost investors. Each investment cost line is weighted by the respective shares ς_{type} and the overall investment cost or again weighted over time with the discount factor δ_{weight}.

Technology-specific financing cost. Assume that certain technologies obtain an interest rate premium ρ so that $i_\rho = i + \rho$. Endeffect (3), interest factor (5), annuity (6), and $WACC = i_\rho$ change accordingly. Note that discount rates are unaffected because they are driven by the share of the respective investor types.

4. Illustrative Examples

We now provide some intuition for handling of investment cost of the three different investor types by considering 2020 and 2040 investments in technologies with different depreciation times

[6] We need to apply a mixed discount rate for all investor types (instead of one for each type) to avoid intertemporal distortions in relative investment decisions. When not doing so, the investor type with highest discount rates has lowest effective investment cost. This effect becomes particularly strong in later periods and leads to exaggerated capacity investments.

neglecting discounting and considering discounting. This allows us to determine the relative competitiveness of investments for the three investor types depending on investment timing, depreciation time, and discounting. Tables 1 and 2 consider the example of a wind turbine investment with a depreciation time of 25 years. Tables 3 and 4 consider the example of a nuclear investment with 40 years of depreciation. For illustrative purposes, we assume that both technologies cost 100 € in 2020 and 2040. We apply an interest rate of 7% and consider 7% discount rate when accounting for discounting.

Table 1: Comparison of 2020 and 2040 wind turbine investments for the three investor types

	2020	2025	2030	2035	2040	2045	2050	Sum	Difference
Investment in 2020									
Normal	100.0							100.0	
Annuity	42.9	42.9	42.9	42.9	42.9			214.5	+114.5%
Capital cost	35.0	35.0	35.0	35.0	35.0			175.0	+75%
Investment in 2040									
Normal					78.2			78.2	
Annuity					42.9	42.9	42.9	128.7	+64.7%
Capital cost					35.0	35.0	35.0	105.0	+34.3%

The endeffect of the 2020 investment is 100%. The endeffect of the 2040 investment is 78.2%. The annuity is 8.58% and the capital cost 7% (per year).

Start with the wind turbine investment in the no discounting case (Table 1). The 2020 investment depreciates completely until 2040 (2016 to 2040 = 25 years) and the 2040 investment depreciates only partly (2036 to 2050 = 15 years) within the model horizon. For the normal investor, installation period and depreciation time translates to an endeffect of 100% for the 2020 investment and of 78.2% for the 2040 investment. The annuities of the above mentioned wind turbine investment are 8.58%. Those annuities need to be paid every year ($5 \times 8.58 = 42.9\%$), accumulating to much more cost (214.5 €for the 2020 investment and 128.7 €for the 2040 investment) than for the normal investor (100 €for the 2020 and 78.2 €for the 2040 investment). Capital cost investors merely take 7% instead of the above mentioned 8.58%, leading to costs for those wind turbines of 175 or 105 €, respectively. Interestingly, the relative competitiveness of the two investments changes for the three investor types. Annuity and capital cost investors improve their relative competitiveness compared to the normal investor for the 2040 investment.[7] The annuity investor is 23% more expensive than the capital cost investor for both investments. Thus, the relative competitiveness between annuity and capital cost investors remains constant.

Now consider a situation with discounting. The corresponding discount factor is presented in the first line of Table 2. We obtain the values in Table 2 by multiplying the corresponding ones in

[7] For the annuity (capital cost) investor cost are 115% (75%) higher for the 2020 investment but only 65% (34%) higher for the 2040 investment.

Table 2: Comparison of 2020 and 2040 wind turbine investments for the three investor types considering discounting

	2020	2025	2030	2035	2040	2045	2050	Sum	Difference
Discount factor	4.1	2.9	2.1	1.5	1.1	0.8	0.5		
Investment in 2020									
Normal	82.0							82.0	
Annuity	35.2	25.1	17.9	12.8	9.1			100.0	+21.9%
Capital Cost	28.7	20.5	14.6	10.4	7.4			81.6	–0.5%
Investment in 2040									
Normal					16.6			16.6	
Annuity					9.1	6.5	4.6	20.2	+21.9%
Capital Cost					7.4	5.3	3.8	16.5	–0.5%

We obtain values from multiplying Table 1 values with the discount factor and divide by 5.

Table 1 with the discount factor and dividing by 5.[8] The relative competitiveness of the investments for the three investor types changes but remains constant for 2020 and 2040 investments. Moreover, investments are now (almost) equally competitive for the capital cost and normal investor and only 22% more expensive for the annuity investor. Additionally, the relative competitiveness between annuity and capital cost investor is the same as under no discounting (annuity investor is still 23% more expensive).

Table 3: Comparison of 2020 and 2040 nuclear investments for the three investor types

	2020	2025	2030	2035	2040	2045	2050	Sum	Difference
Investment in 2020									
Normal	97.1							97.1	
Annuity	37.5	37.5	37.5	37.5	37.5			262.5	+170.3%
Capital Cost	35.0	35.0	35.0	35.0	35.0			245.0	+152.3%
Investment in 2040									
Normal					68.3			68.3	
Annuity					37.5	37.5	37.5	112.5	+64.7%
Capital Cost					35.0	35.0	35.0	105.0	+53.7%

The endeffect of the 2020 investment is 97.1%. The endeffect of the 2040 investment is 68.3%. The annuity is 7.5% (per year).

The difference between the capital cost and annuity investors is smaller when considering investments with a longer depreciation time such as nuclear power plants (see Tables 3 and 4). The annuity reduces to 7.5% so that the annuity investor is only 7% more expensive than the capital cost investor. Moreover, the relative competitiveness to the normal investor fundamentally

[8]Note that the discount factor already accounts for a period of 5 years.

changes. The normal investor only carries cost of 97.1 €(2020 investment, 35 years within the time horizon) or 68.3 € (2040 investment, 15 years). The annuity investor is 170% and the capital cost investor 152% more expensive when neglecting discounting. The difference drops to 22% (annuity) and 14% (capital cost) when applying discounting (Table 4).

Table 4: Comparison of 2020 and 2040 nuclear investments for the three investor types including discounting

	2020	2025	2030	2035	2040	2045	2050	Sum	Difference
Discount factor	4.1	2.9	2.1	1.5	1.1	0.8	0.5		
Investment in 2020									
Normal	79.6							79.6	
Annuity	30.8	21.9	15.6	11.1	7.9	5.7	4.0	97.1	+22%
Capital Cost	28.7	20.5	14.6	10.4	7.4	5.3	3.8	90.6	+13.8%
Investment in 2040									
Normal					14.5			14.5	
Annuity					7.9	5.7	4.0	17.7	+22%
Capital Cost					7.4	5.3	3.8	16.5	+13.8%

We obtain values from multiplying Table 3 values with the discount factor and divide by 5.

We can already derive first hypotheses about the effects of investor type heterogeneity from those simple illustrative examples. Discounting fundamentally reduces differences between investors and keeps the relative competitiveness constant within the entire time horizon. In turn, neglecting discounting, favors investments from the normal investor. However, relative competitiveness between annuity and capital investor always remains the same, although annuity investors are closer to cost of the capital cost investor when an investment's depreciation time is longer.

5. Calibration

Investment cost and depreciation time. Table 5 summarizes investment cost and depreciation times for generation, storage, and transmission technologies. Observe that cost for conventional gas (gas-CCGT, gas-ST, gas-OCGT) technologies and lignite remains constant over time. Cost for all other generation technologies drop over time, whereas the drop is most pronounced for solar and wind offshore. Furthermore, power-to-gas cost are assumed to be constant as well because the technology is not applied yet. In turn, cost of batteries falls tremendously from 1,740 to 440 €/kW, assuming an energy-to-power ratio of 4. Finally, we consider transmission technologies. AC-line is less expensive than DC-line but overall line length is higher and only DC-lines can connect countries via water.

CO_2 price and electricity demand. When modeling the European power market, one can either decide to establish a quantity target or CO_2 prices as outcome of the quantity regulation, in other words, EU ETS including MSR. We opt for the second option and obtain CO_2 from Azarova and

Table 5: Investment cost and depreciation time (in years) for generation (€/kW), storage (€/kW), and transmission (€/MW per km) technologies

	2020	2030	2040	2050	Depreciation
Bio-CCS	4,361	4,272	4,183	4,139	25
Bioenergy	4,236	4,149	4,063	4,020	25
Coal	1,500	1,410	1,380	1,365	40
Coal-CCS	3,415	3,210	3,142	3,108	40
Gas-CCGT	850	850	850	850	25
Gas-CCS	1,495	1,495	1,495	1,495	25
Gas-OCGT	437	437	437	437	25
Gas-ST	850	850	850	850	25
Geothermal	11,993	11,498	11,127	11,004	30
Lignite	1,640	1,640	1,640	1,640	40
Nuclear	6,006	5,082	4,488	4,356	40
Oil	822	822	822	822	25
Solar	1,027	858	780	715	25
Wind offshore	3,024	2,520	2,268	2,088	25
Wind onshore	1,397	1,339	1,310	1,296	25
Power-to-gas	1,520	1,520	1,520	1,520	20
Battery	1,740	1,120	780	440	16 to 22
AC-line	770	770	770	770	50
DC-cable	1,152	1,152	1,152	1,152	50

We restrict hydro and pump storage capacity to existing capacity and thus refrain from showing cost and depreciation time.
We assume energy-to-power ratios (kWh/kW) of 720 for power-to-gas and 4 for batteries. Pump storage ratios are 4 in Slovenia (185 MW installed generation capacity) and 3,685 in Norway (1,344 MW installed generation capacity).

Mier (2020) for a scenario that relies on current EU ETS legislation (including MSR cancelling) and neglecting a wind turbine technology boost from 2040 onwards. Note that such a scenario does not take the 2045 carbon neutrality target of the EU into account. Table 6 shows the outcome. The CO_2 price is 26 €/ton in 2020 and increases up to 224 €/ton in 2050.

Electricity demand is the crucial determinant for overall capacity expansion. We obtain electricity demand from a CGE calibration that accounts for certain quantity targets and electrification of industrial and transport sectors (Mier et al., 2020, Siala et al., 2020). Table 6 shows the respective country values. Overall electricity demand doubles from 3,089 TWh to 6,204 TWh.

Table 6: CO_2 price (€/ton) and electricity demand (TWh/a)

	2020	2025	2030	2035	2040	2045	2050
CO_2	26	34	55	85	119	149	224
Electricity demand	3,089	4,153	4,500	5,081	5,480	5,830	6,204

6. Results

We now analyze results by focusing on three different objectives in each of the following three subsections. Subsection 6.1 shows the impact of the three different investment cost specifications for the respective investor types and the role of discounting for investment timing. Subsection 6.2 presents diverging behavior of the three investor types when varying discount and interest rates. Finally, Subsection 6.3 uses type-specific discount and interest rates for the three investor types, accounts for investor type heterogeneity in the same markets by assigning shares to each investor type, and applies technology-specific interest premia. We present results by showing one (three, one) diagram with an upper and lower panel in Subsection 6.1 (6.2, 6.3). The upper panel invariable demonstrates the evolution of installed generation capacity (left axis, in GW) by technology-type as well as storage (blue squares) and transfer capacity (yellow triangles, right axis, in GW).[9] The lower panel depicts the evolution of generation (left axis, in TWh) and CO_2 emissions (grey diamonds, right axis, in Mt). Both panels cluster model specifications by years from 2020 to 2050.

6.1. Investment Cost Specifications

The first column of each cluster in Figure 1 reflects investments (and related generation) of the *normal* investor, the third those of the *capital cost* investor, and the fifth refers to the *annuity* investor. The second, fourth, and sixth column of each cluster refer to the respective investor type when neglecting discounting. We start with the normal investor and describe the difference to the capital cost and annuity investor afterwards.

Normal investor. The normal investors applying discounting (first column of each cluster) increases wind capacity (wind onshore and wind offshore) from 362 GW in 2020 to 974 GW in 2050 (+169%) and intermittent renewables capacity (additionally hydro and solar) from 611 to 1,592 GW (+160%), whereas overall capacity increases by 127% to 1,399 GW. Thus, the share of wind (intermittent renewables) changes from 33% (56%) in 2020 to 39% (64%) in 2050. Other decisive technologies are gas-CCS and nuclear. Gas-CCS is first installed in 2030 and makes up 384 GW in 2050 (15% of total capacity). Nuclear capacity (54 GW or 5% in 2020) increases by 93 GW until 2050 constituting a share of 6% of total installed capacity. Turning to generation, wind (intermittent renewables) makes up 29% (45%) of total generation in 2020 and already 40% (55%) in 2050. Observe that total generation increases from 3,326 to 6,710 TWh driven by rising annual demand (see Section 5).[10] The gap between total generation and intermittent renewables is mainly filled by gas-CCS (22%) and nuclear (17%). Other gas technologies and bio-CCS are negligible for daily generation but are somewhat relevant to balance intermittent generation (5% of total generation, 15% of total capacity). Moreover, generation capacity of storage technologies increases from 56 to 153 GW in the period 2020 to 2050. Stored energy increases by a similar extent to 106 TWh.

[9]Storage capacity refers to generation capacity (for decharge) and not reservoir capacity which would be depicted in GWh.

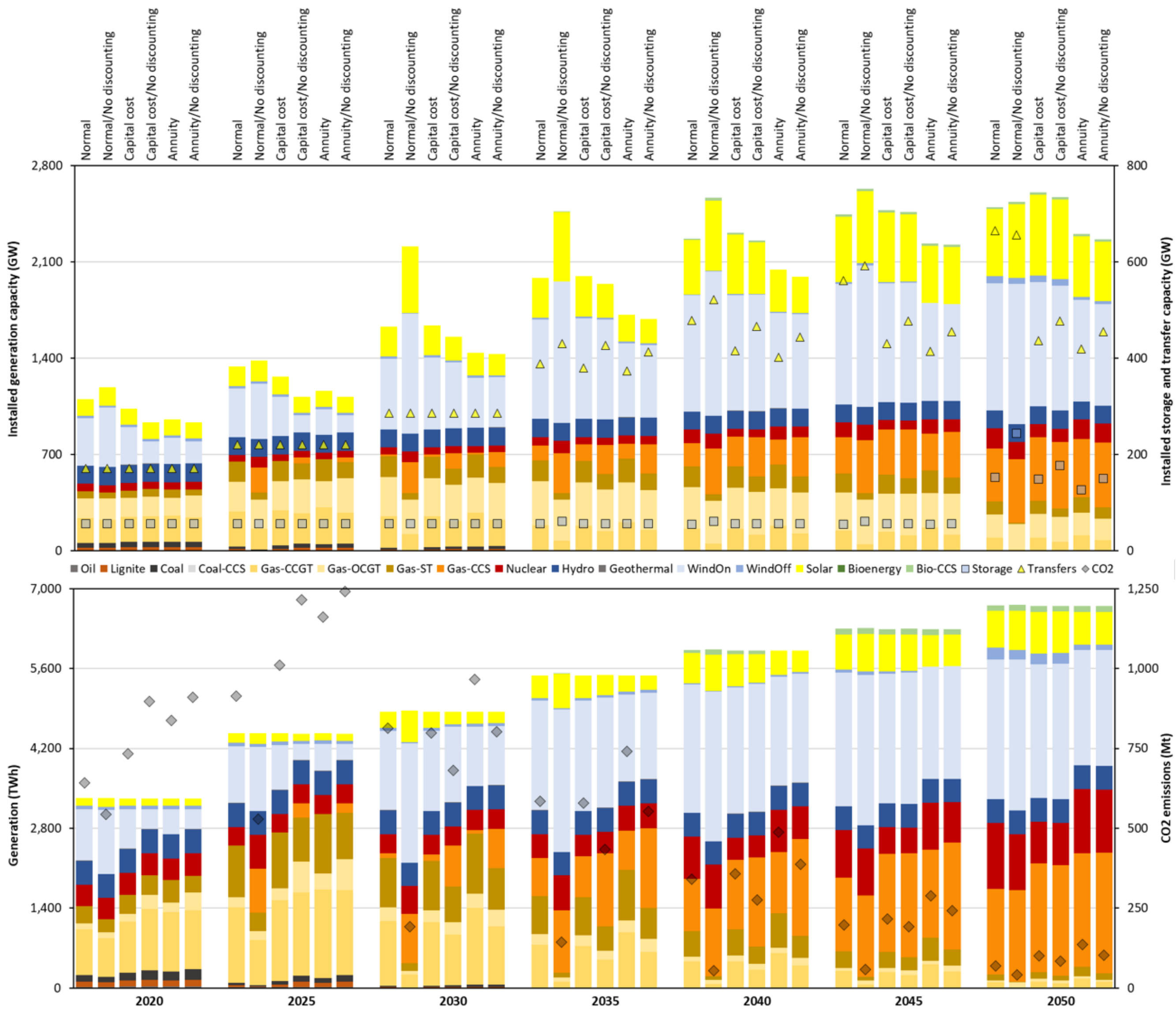
[10]The difference between generation and demand—500 TWh in 2050—lies in storage and transmission losses.

Transfer capacity (transfers) increases from 171 to 665 GW (325 to 1,713 TWh) in 2050. Note that the overall storage capacity increase seems quite substantial but the overall amount of stored energy (106 TWh stored to 6,710 TWh generated) is quite small. On the contrary, the level of transfer capacity and transfers are fundamental which is required for balancing spatial differences in the availability of intermittent renewables. 665 GW (1,713 TWh) of transfer capacity (transfers) is a share of 48% of installed generation capacity (26% of total generation, that is, every fourth unit of electricity generated is traded to another country). Finally, CO_2 emissions drop from 641 to 70 Mt (-89%) within the period 2020 to 2050. Observe that CO_2 emissions increase in 2025 and drop below 2020 level in 2035 (585 Mt).

The normal investor neglecting discounting (second column) shows quite a different investment decision pattern from 2020 onwards. Some of the differences balance out until 2050, whereas others are persistent even over the long term. No discounting leads to 85 GW (101 GW) more wind (intermittent renewables) capacity already in 2020 so that wind (intermittent renewables) generation is 23% (16%) higher. In 2050, wind (intermittent renewables) capacity and generation are still 86 GW or 154 TWh (134 GW, 201 TWh), respectively, higher. Thus, the initial 2020 investments (and related generation) remain until 2050. Meanwhile—observe the peak in 2030 and 2035— the differences to the case with discounting are even bigger. For example, wind (intermittent renewable) capacity and generation are 66% or 47% (70%, 43%), respectively, higher in 2030. Additionally, substantial investments in gas-CCS already occur in 2025 (181 GW) so that gas-CCS already assumes a generation share of 17%. Also nuclear capacity is 31 GW higher in 2025 compared to the situation with discounting. Higher gas-CCS and nuclear capacities bring benefits of lower capacity from other gas technologies and no more coal/lignite from 2025 onwards. However, differences in 2050 mainly rely on higher generation from wind (+6%), solar (+7%), and gas-CCS (+7%), whereas nuclear generation is 15% lower. Higher wind and solar generation is accompanied (or fosters) higher storage capacity (244 GW compared to 153 GW with discounting). Transfer capacity (and transfers) is slightly lower but still dominant in balancing intermittent generation compared to storage capacity (and stored energy). We observe a deeper decarbonization (40 Mt in 2050). However, the path towards 2050 is fundamentally less carbon intensive. CO_2 emissions already drop to 192 Mt in 2030 (compared to 813 Mt). The small absolute difference of 30 Mt in 2050 is thus misleading from the perspective of climate change.

Capital cost investor. The capital cost investor considering discounting (third column) shows a considerably different investment pattern (compared to the normal investor with discounting). Installed capacity of wind (intermittent renewables) is 20% (12%) lower in 2020, almost on the same level from 2030 to 2045, and finally 3% lower (5% higher) in 2050. Solar capacity in particular is 21% higher in 2050. However, the most substantial differences result from adverse behavior of gas-CCS and nuclear. Gas-CCS capacity is structurally higher (20% in 2050) and nuclear capacity always lower (-34% in 2050). As before, other gas technologies and bio-CCS play minor roles for the capacity mix. Wind generation is in fact 5% lower and solar generation 14% higher in 2050. The gas-CCS-nuclear differential is persistent (+26% gas-CCS generation, -36% nuclear generation). Finally, observe that transfer capacity (and transfers) are strikingly lower than for

Figure 1: Impact of investor type and the role of discounting



the normal investor (437 GW and 1,191 TWh in 2050 compared to 665 GW and 1,713 TWh). Storage capacity in turn is similar. The lower wind generation requires less transfer capacity. Or conversely, investments in transfer capacity are more expensive (relatively) for the capital cost investor, hampering wind deployment and finally fostering (more local) solar expansion. The capital cost investor without discounting (fourth column) invests (and generates) similar to the one applying discount rates, at least in the long run, i.e., differences are negligible from 2040 onwards. Before 2040, the investor without discounting invests fundamentally less than the one applying discounting. For example, wind capacity is 111 GW or 38% lower in 2020. Solar capacity is 46

GW lower in 2030 (-21%). Interestingly, storage and transfer capacity are 19% or 9%, respectively, higher in 2050. The investor with discounting invests earlier in wind and solar capacity. The investor without discounting invests later at a point where storage technologies are cheaper and transfer capacity is less restricted (transfer capacity expansion is restricted until 2030 and free from 2035 onwards).

Annuity investor. As we have already shown in the illustrative examples in Section 4, the annuity investor is the most expensive one. We start by looking at the results with the discounting. Wind (intermittent renewables) capacity is already 43% (25%) lower in 2020 (compared to the normal investor applying discounting). The differences become smaller from 2030 onwards and are virtually constant until 2050 (22% lower wind and 17% lower intermittent renewables capacities). Conversely, gas-CCS capacity is 23% higher in 2050, whereas nuclear capacity is 7% lower. Again, we observe the adverse pattern of gas-CCS and nuclear. The generation pattern is consistent with the capacity pattern. For the no discounting case, qualitative changes are similar to those of the capital cost investor when neglecting discounting. Wind power capacity is already lower in 2020, but similar in 2030 onwards. The annuity investor (with and without discounting) tends to react less intensely than the capital cost investor but pattern-wise both investors are somewhat similar. The overall costs of investment are higher due to the annuity specification of investment cost. The annuity specification also fosters more long-term investments compared to the capital cost investor. Hence, nuclear capacity (40 years of depreciation) is higher. However, transfer capacity is lower (50 years of depreciation) because less transfers are needed due to lower deployment of wind power.

Investor Type Patterns. The normal investor invests early and predominantly relies on wind power and transfers. The capital cost investor takes over investments from the normal investor but relies more on solar power and less on nuclear capacity. The annuity investor invests the least; in particular, with wind and solar deployment being the lowest, whereas reliance on gas-CCS and nuclear is fundamentally higher. Interestingly, shifting between discounting and no discounting is fundamentally different for the normal investor. No discounting increases overall installed capacity for the normal investor but decreases it for the capital cost investor. However, what is similar is that CO_2 emissions are always lower for both investors when neglecting discounting, thus, which means discounting hampers decarbonizing the power system.

6.2. Interest and Discount Rates

We now present results for the normal (Figure 2), capital cost (Figure 3), and annuity (Figure 4) investors for five different discount and interest rates (9%, 7%, 5%, 3%, 1.5%). The first column of each cluster shows the outcome for 9% and the last for 1.5%. For parsimony, we assume that discount and interest rates are the same and simply refer to them as *rates* in the following. Observe that we changed the scale of the left axes (compared to Figure 1) for installed capacities (to 3,600 GW) and generation (to 7,500 GW). The scale of the right axes remains the same. Note that the 7% outcomes are the same as shown in Figure 1 for the case with discounting (columns one, three, and five). We thus mainly refer to (absolute and relative) differences of the respective specification to 7%.

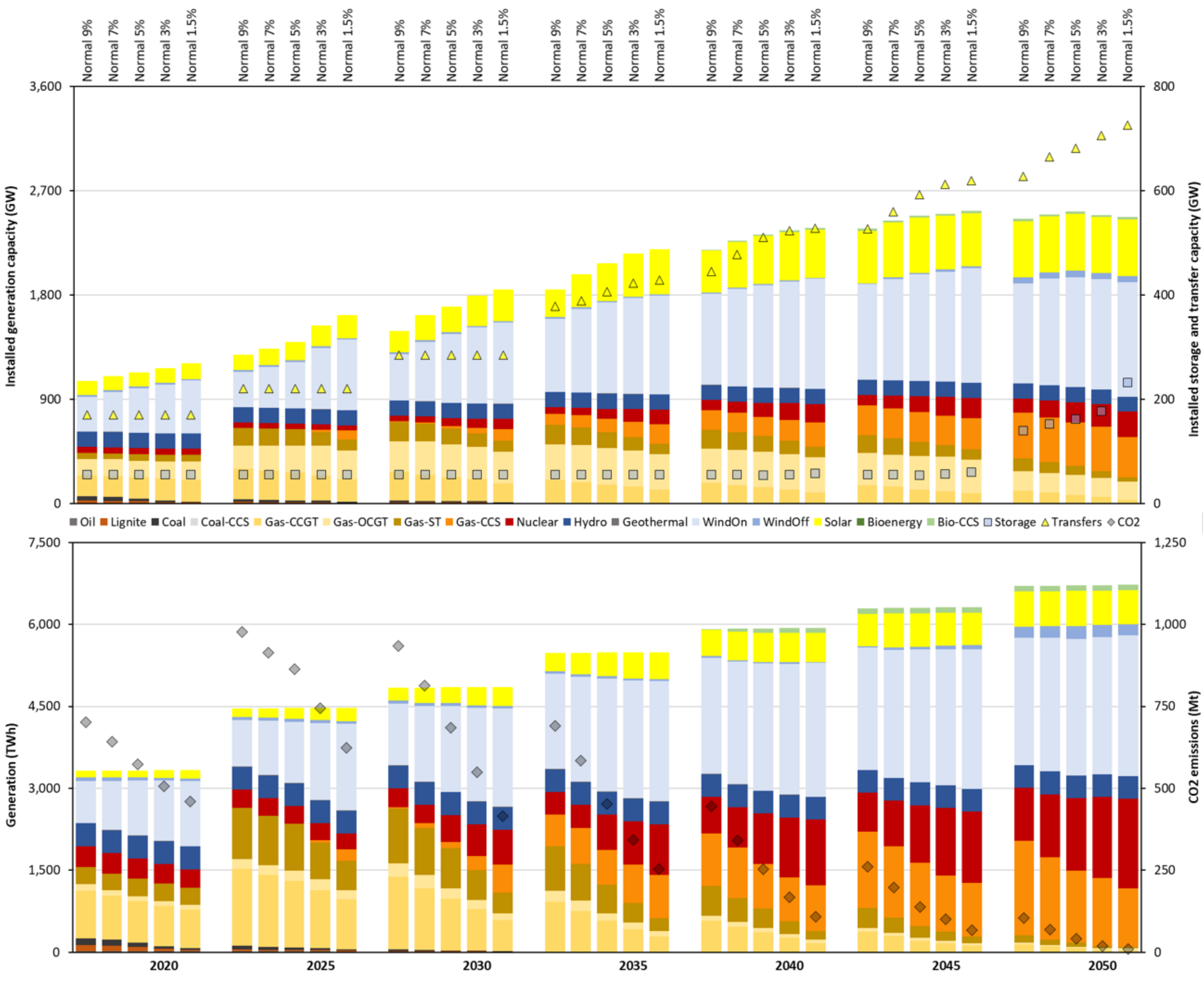
Normal investor. Before describing the outcome from different rates in detail, let us first summarize some consistent developments across specifications. Solar and bio-CCS capacity and generation is quite similar across specifications. Minor differences exists in the bio-CCS starting investments in 2040 but immediately level out in 2045. Solar differences are apparent until 2035 (-15% generation for *normal 9%* and +25% for *normal 1.5%*) but assume negligible levels from 2040 onwards. Hydro differences are negligible as well and oil, lignite, and coal are all phased out by 2035. However, they already play a negligible roles from 2025 onwards. In the following, we thus concentrate on gas technologies, nuclear, and wind.

Start with the *normal 9%*. In 2020, such a specification installs 45 GW (-12%) less wind power compared to our benchmark specification *normal 7%*. The difference increases to 112 GW (-21%) in 2030 but then drops and remains almost constant from 2040 onwards with 2050 wind capacity of 551 GW (-61 GW, -6%). The lower wind expansion impacts the composition of gas capacity. In 2030, gas-CCGT and gas-ST capacity is 19 and 15 GW higher (8 and 10%) but gas-OCGT and gas-CCS 19 and 10 GW lower (-7% and -78%). The lower gas-CCS capacity is associated hand with depressed CO_2 abatement incentives (due to higher discount rates). Lower wind deployment and less requirements for balancing wind output explains the substitution of the peak technology (gas-OCGT) by base ones (gas-CCGT, gas-ST). Until 2050, the differences for gas-OCGT disappear but those for gas-CCGT and gas-ST keep persistent with 17 GW (+18%) or 14 GW (+14%), respectively, more capacity. Interestingly, the difference in gas-CCS capacity turns in 2050 (+12 GW, +3%). Conversely, nuclear capacity is structurally lower from 2035 onwards with 24 GW less nuclear capacity in 2050 (-16%). Observe that storage and transfer capacity are also structurally lower (-14% and -6% in 2050) due to lower temporal (storage) and spatial (transfer) balancing requirements.[11] The generation pattern mirrors the capacity development whereas differences in gas-CCS, nuclear and wind generation become more apparent. Gas generation is structurally higher, finally leading to emission of 105 Mt (compared to 70 Mt for normal 7%).

Normal 5% (*3%*) already installs 36 GW (73 GW) more wind capacity in 2020. Investment differences peak in 2030 with 84 GW (141 GW) reflecting 16% (27%) more wind capacity. Differences then drop until 2050 with just 34 GW or 4% (30 GW, 3%) more wind capacity. Higher wind capacity reduces the need for classic gas technologies by 37 GW (81 GW), whereas gas-CCS capacity is 7 GW (36 GW) and nuclear capacity is 19 GW (30 GW) higher by 2030. This pattern slightly changes until 2050. Classic gas capacity is still lower by 32 GW (78 GW) and nuclear capacity higher by 26 GW (47 GW). However, gas CCS capacity is 10 GW (1 GW) lower. Observe that total capacity is higher for *normal 3%* until 2045 (with highest differences in 2030). However, total capacity is lower in 2050 reflecting lower wind capacity and a higher reliance on nuclear. Generation patterns mainly reflect those of installed capacity. Observe that (still carbon-emitting) gas-CCS generation is structurally higher for *normal 5%*, whereas *normal 3%* relies more

[11] Final stored energy (transfers) are 6% (9%) lower.

Figure 2: Impact of varying discount and interest rates on investment and generation behavior of the normal investor



on (completely carbon-free) nuclear, leading to final CO_2 emissions of 41 Mt (5%) or 19 Mt (3%), respectively.

Finally, turning to *normal 1.5%* which mainly matches (and reinforces) the trends already described for the 3% specification. Wind capacity (generation) is 110 GW (281 TWh) higher in 2020 compared to the one using 7%. Differences peak in 2025 with 252 GW (577 TWh) more wind capacity (generation) but level out until 2050 to 64 GW (115 TWh). Classic gas capacity is 227 GW (share of 9%) but responsible for 101 TWh generation only (share of 1.5%). Reliance on gas-CCS is structurally lower (-34 GW, -444 TWh) but on nuclear (+70 GW, +491 TWh) considerably higher, resulting in 10 Mt CO_2 emissions. Finally, storage and transfers capacities are higher by 52% or 17%, respectively.

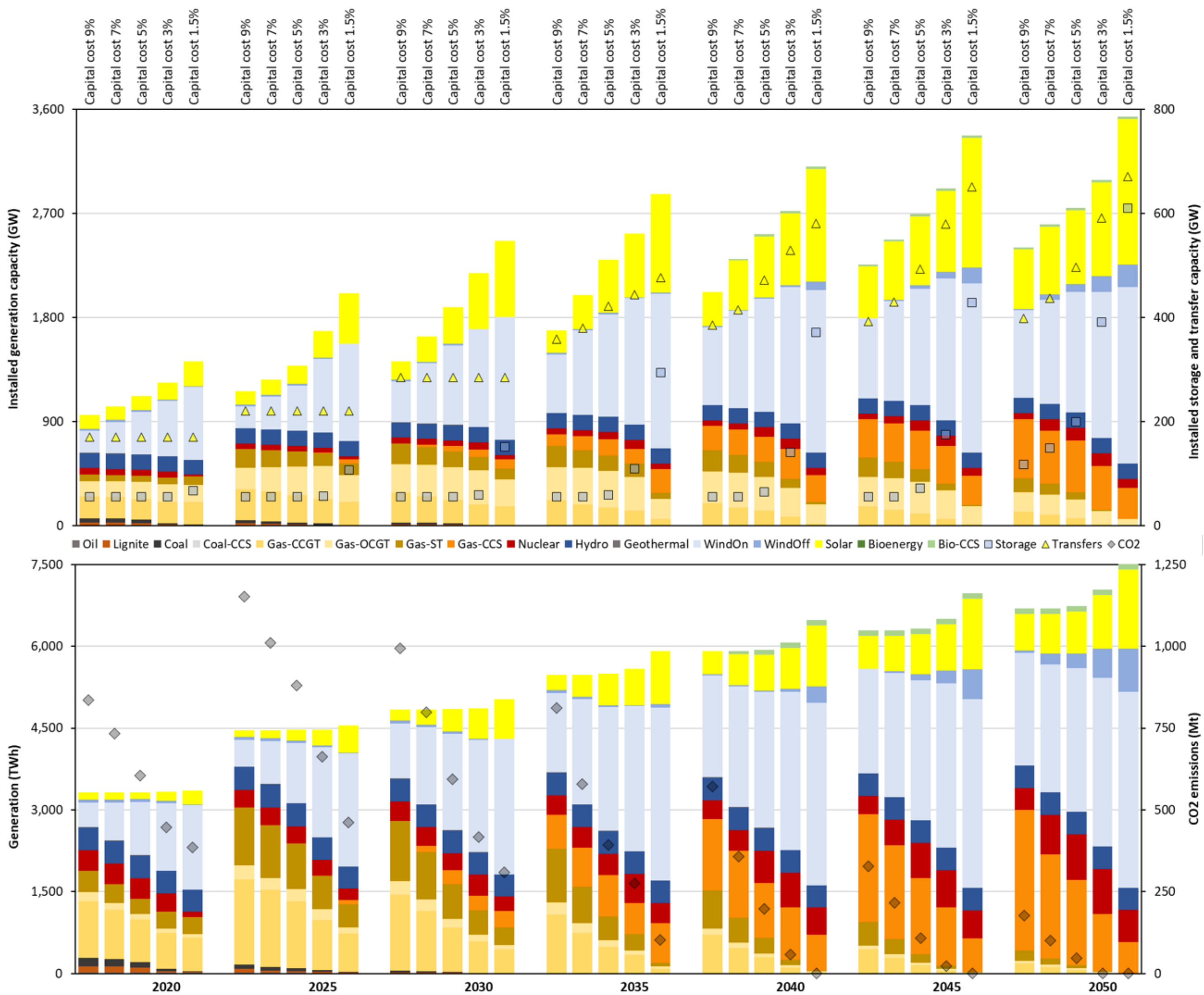
The magnitude of differences is 13% (9%) for wind capacity (generation), 12% (44%) for gas-CCS, and 63% (58%) for nuclear capacity when changing rates from 9% to 1.5%. Wind differences in particular are not so high. Interestingly, there is adverse behavior depending on the rates for usage of gas-CCS and nuclear. Both technologies are substitutes when reducing or increasing, respectively, rates. Lower rates lead to structurally more nuclear capacity (and generation). While higher rates lead to more gas-CCS. Moreover, lower rates also foster transfer capacity expansion, indicating that lower rates foster more durable (regarding depreciation time) investments such as nuclear (40 years) and transfer capacity (50 years). Higher rates, in turn, rely more on less durable ones such as gas-CCS (25 years). However, the gas-CCS vs. nuclear pattern is overlapped by decarbonization trends. We cannot determine whether this is the cause or a effect of the technologies' relative competitiveness when changing rates. Remember that lower discount rates promote an earlier deployment of capacity (as also shown in Figure 1) for the normal investor because the relative investment cost when evaluating the cash flow fosters early investment at cost of later investments. This explains declining total capacity levels in 2050 and quite substantial usage of gas-CCS and nuclear (for generation, i.e., high full-load hours).

Capital cost investor. For the capital cost investor there are only some similarities across specifications for bio-CCS. For all rates except 9%, bio-CCS expansion starts in 2040. However, 2050 generation is the same for all rates (101 TWh, maximum biomass usage).

We start again with describing differences of *capital cost 9%* to the 7% specification. Wind capacity (generation) is 81 GW (246 TWh) lower in 2020. Differences grow until 2035 (220 GW, 469 TWh) and are still considerable in 2050 (181 GW, 431 TWh), reflecting a reduction in the wind power share of 4% (capacity) or 7% (generation), respectively. Solar pattern is comparable to the wind pattern. Moreover, usage of conventional gas is structurally higher (+49 GW, +147 TWh), gas-CCS as well (+49 GW, +670 TWh), and nuclear lower (-42 GW, -333 TWh). Storage and transfer capacity are lower by 21% or 9%, respectively. Final CO_2 emissions are 177 Mt (compared to 102 Mt).

Lowering the rates goes hand in hand with fundamentally more investments in wind and solar capacity. A rate of 5% (3%, 1.5%) increases 2020 wind capacity by 33% (69%, 118%). Absolute differences grow from 96 GW (199 GW, 344 GW) to 164 GW (449 GW, 776 GW) in 2050—reflecting 17% (47%, 82%) more wind capacity. Similar for solar capacity. Differences increase

Figure 3: Impact of varying discount and interest rates on investment and generation behavior of the capital cost investor



from 0 GW (28 GW, 96 GW) in 2020 to 49 GW (226 GW, 669 GW) in 2050 (+17%, +47%, +82% in 2050 levels compared to 7% rates). Interestingly, gas-CCS capacity decreases constantly with lower rates (-13 GW for 5%, -80 GW for 3%, and -188 GW for 1.5%) but nuclear evolution is quite different. Nuclear capacity is slightly higher for the 5% and 3% specifications (112 GW and 110 GW vs. 97 GW in 2050) but lower for *capital cost 1.5%*. Storage capacity and transfer capacity is also structurally higher for lower rates. In particular, storage capacity is 34% (163%, 310%) higher for 5% (3%, 1.5%), reflecting or fostering wind and solar expansion. Applying rates of 3% and 1.5% even lead to negative CO_2 emissions (the scale does not reflect that fact) of -14 Mt (3%) or -46 Mt (1.5%) due to high shares of intermittent renewables (71% and 83% of total generation) combined with negative emissions from bio-CCS.

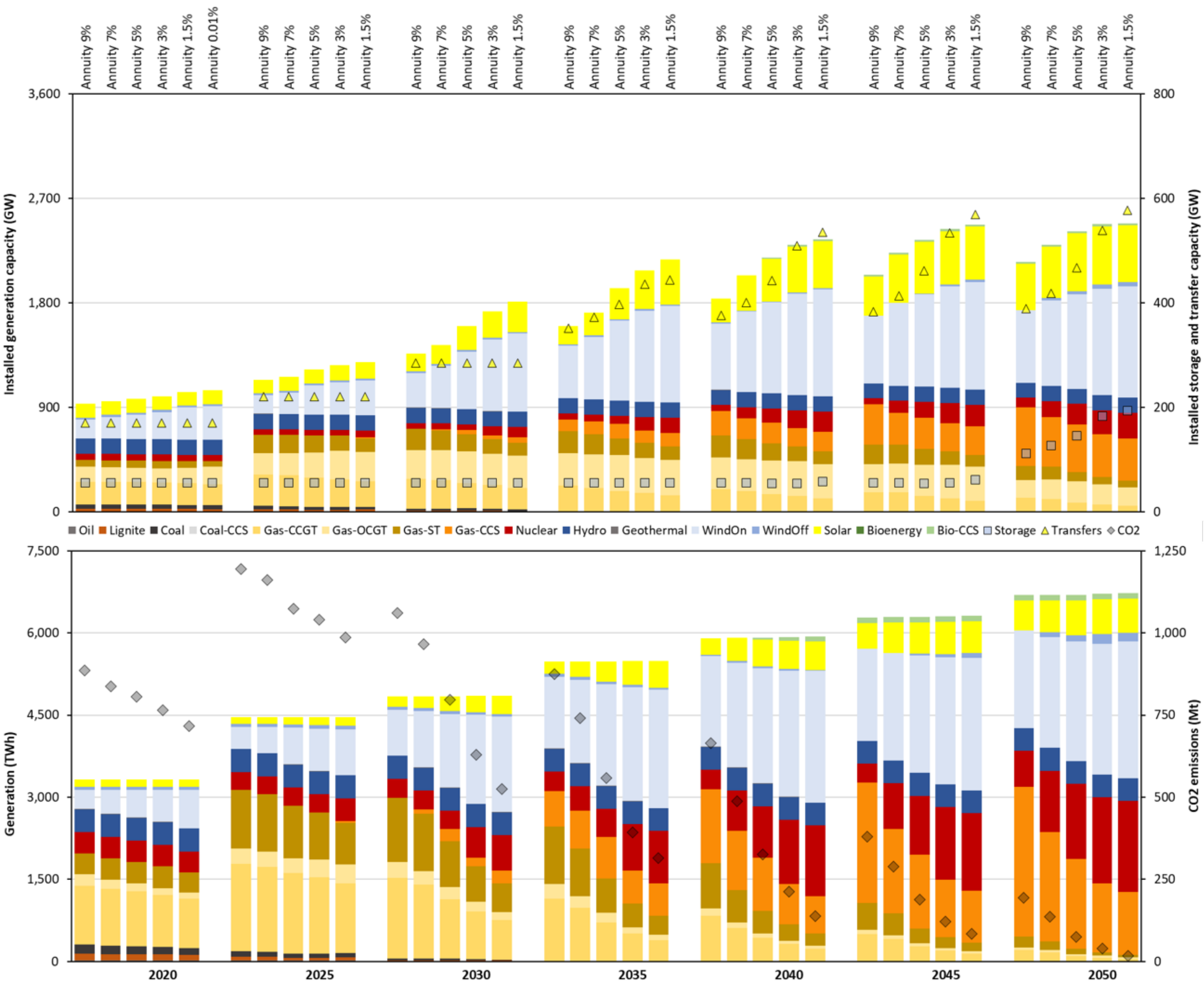
Higher rates greatly suppress investments and lower rates foster investment. For example, when changing rates from 9% to 1.5% wind capacity grows by 146% in 2020 and 99% in 2050. Solar differences are 81% in 2020 and even 126% in 2050. Higher wind and solar capacity for lower rates suppress investments in gas-CCS and nuclear capacity, whereas gas-CCS production is quite substantial (39%) when applying highest rates (9%). When comparing those findings with the one shown by Figure 1 in Subsection 6.1 observe that the no discounting effects is overruled by the interest rate effect, i.e., lower investment from neglecting (or reducing) discounting can no linger be observed in Figure 3 anymore. However, the entire discounting effect is from less interest because the timing of investment does not matter so much due to the constant payments (of interest) for capital over time.

Annuity investor. Annuity 9% installs 26 GW (-13%) less wind capacity in 2020 compared to *annuity 7%*. Differences grow continuously to 135 GW (-18%) in 2050. The solar pattern differs. We observe -11 GW in 2030, differences peak in 2040 at -110 GW, and become smaller until 2050 with -38 GW. In 2050, gas-CCS capacity is 77 GW (+18%) higher and nuclear 56 GW lower (-40%). Differences for conventional gas technologies and bio-CCS are negligible. However, higher rates lead to substantial lower investments into storage and transfer capacity (-12% and -7% in 2050) again. Final CO_2 emissions are at 196 Mt (compared to 136 Mt) for *annuity 7%*).

Decreasing rates have a strong impact on wind, solar, nuclear, and gas-CCS. The specification applying 5% (3%, 1.5%) installs 21 GW more wind capacity (47 GW, 87 GW) in 2020. Differences grow to 81 GW (197 GW, 238 GW) in 2050. Solar capacity is 61 GW (58 GW, 47 GW) higher in 2050. Gas-CCS capacity in turn is 12 GW lower (-57 GW, -59 GW), whereas nuclear capacity is 35 GW (65 GW, 79 GW) higher. Observe that the gas-CCS capacity drops by -3% (-13%, -14%) but generation by -18% (-37%, -42%) in 2050.

Higher rates dramatically decrease investments in wind and nuclear power. In turn, gas-CCS and even partly conventional gas technologies play a major role. Lower rates in turn foster deployment of wind, solar, storage, and transfer capacity. Additionally, nuclear capacity becomes higher. Finally, decarbonization is also higher with lower rates. Observe that the role of conventional gas technologies as back-up technologies is still substantial for all rates (compare share of capacity with share of generation).

Figure 4: Impact of varying discount and interest rates on investment and generation behavior of the annuity investor



Investor Type Patterns. Each investor type has a distinct pattern when varying discount and interest rates, although those of the normal and annuity investor are structurally more similar than those of the capital cost investor. Let us start with similarities across types. Higher rates lead to less investments (less installed capacity), and lower rates to more because investments become cheaper for lower interest rates. Wind capacity is always higher for lower rates as it is storage and transfer capacity; resulting in a deeper decarbonization for lower rates because most investments take place in low-carbon (gas-CCS) or carbon-neutral (wind, solar, nuclear) technologies. The impact of negative-carbon (bio-CCS) technologies is the same across types because they all increase bio-CCS generation up to the biomass limit (but overall, the effect is small).

Normal and annuity investor additionally contain some similarities. Observe the substitution effect between gas-CCS and nuclear. Final gas-CCS and nuclear levels are even comparable for lower rates but differ quite substantially for higher rates. However, those differences can be explained by the relative competitiveness of investing between those two types. In this case, the normal investor incurs a fundamentally lower cost when it comes to investment, which results in more investments. When investment cost drops (due to low interest rates), differences become smaller and cost of generating electricity plays a more dominant role. Moreover, conventional gas technologies serve as back-up to balance intermittent renewables. Qualitative developments of storage capacity, transfer capacity, and CO_2 emissions are the same, although absolute levels differ (normal investor has higher storage capacity, higher transfer capacity, and lower emissions). Higher transfer capacity comes from fostering more durable investments for the normal investor. Observe that those three qualitative patterns are valid for the capital cost investor as well, whereas absolute storage levels higher for low rates and CO_2 accompanying are lower.

Comparing the capital cost pattern with that of the normal investor presents structural differences. Observe that the reaction of the capital cost is (1) more extreme and (2) the entire pattern is different. The capital cost investor overcomes the substitution of gas-CCS and nuclear power by means of wind and solar expansion, whereas the normal investor adheres to fundamental substitution effects between gas-CCS and nuclear. Bear in mind that the duration of an investment is not important for relative investment expenses for the capital cost investor. Capital cost investors only pay an interest rate for invested capital regardless of the duration of the investment. In turn, the endeffect in the normal investor optimization problem reflects the duration of the investment. Moreover, the timing of the investment cost seems also to be decisive. The capital cost investor has running cost from investments, whereas the normal one carries the investment burden in the period of investment. Such normal specification seems to hamper expansion at the end of the model horizon when reducing rates.

6.3. Investor Type Heterogeneity and Technology-Specific Financing Cost

We demonstrate the impact of different investor types as well as discount and interest rate in the previous subsections. All three investor types reflect existing investors. A normal investor might be a public company that receives guaranteed credit and plans more long-term and eventually close to invest socially optimal. Such an investor would have lowest interest and discount rates. A *capital* *cost* investor might be a private but big company with sufficient own capital to back-up credits and plan projects. Such an investor would have higher interest and discount rates compared to a *normal* investor. Finally, the *annuity* investor is the most expensive from its specification and it is likely that such an investor—who completely builds on debt capital—has highest interest and discount rates. An example might be small businesses or even private households or community/cooperative that invest in a solar PV. We therefore assume interest and discount rates of 3%, 5%, and 9% for normal, capital cost, and annuity investors. We run the model with those interest and discount rates and obtain the first three columns of each cluster in Figure 5. Additionally, we acknowledge that in a power market such as the European one, there is not just one investor type, but rather a mixture of the three described; that is, investor type heterogeneity. For parsimony, we assume that each investor type has the same share in each country.12 From this, we calculate a weighted discount (and interest rate) used to calculate a weighted discount factor to evaluate cash flows streams (see Section 3).[12]

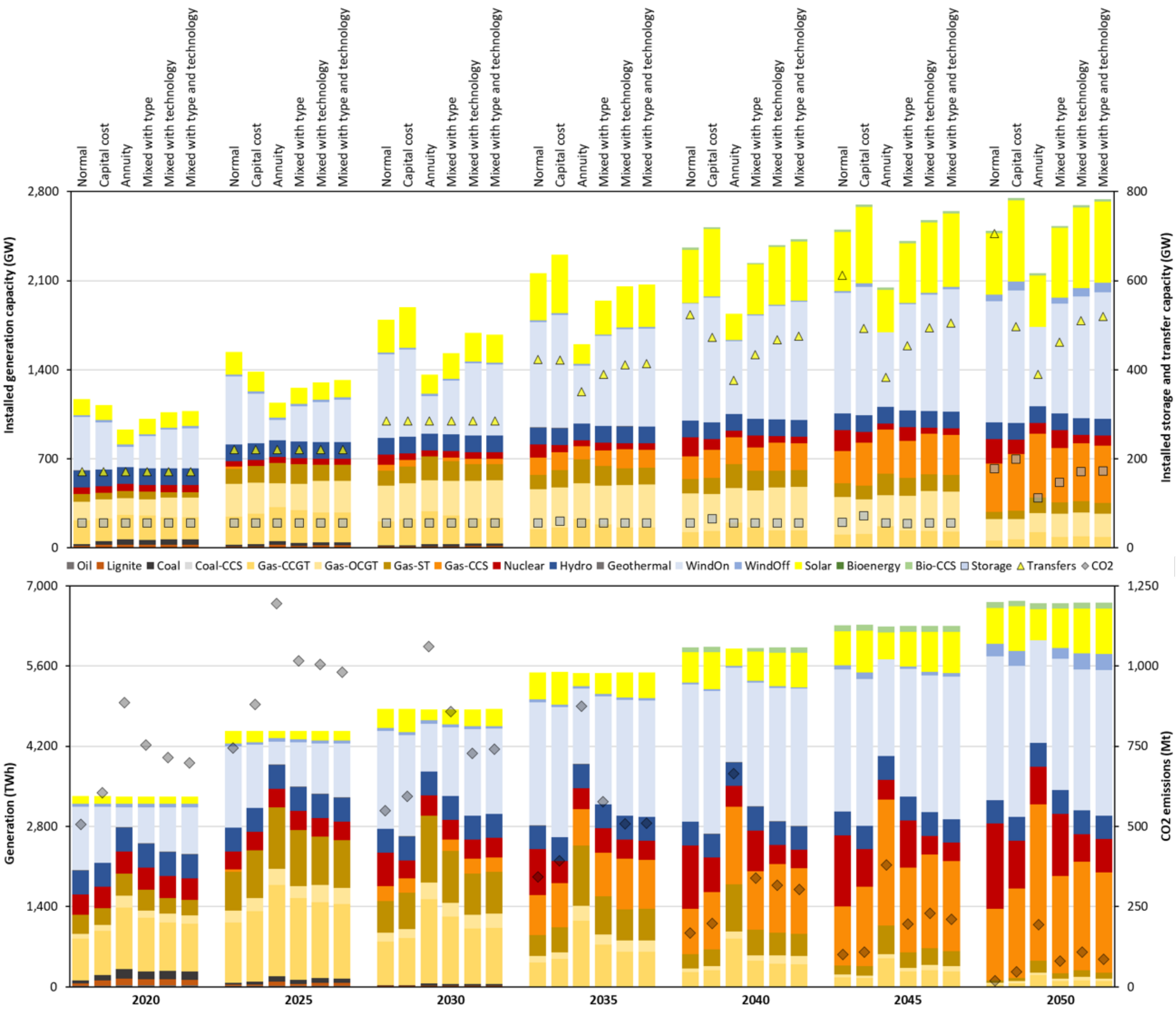
Note that endeffects, capital cost, and annuities are still investor dependent. This specification is shown in the fourth column of each block (mixed with type). We apply investor-unspecific endeffects, capital cost, and annuities in column five (*mixed with technology*). Here, we use the standard interest and discount rate of 7% but dedicate additional premiums for technologies to account for project-specific drivers of investment cost. We assume that transmission technologies and renewable technologies (wind, solar, bioenergy, bio-CCS) receive a premium of 1%, resulting in interest rates of 6% when investing in those technologies. Low carbon technologies such as gas-CCS and storage technologies retain the 7%. All other technologies (including nuclear albeit it is low carbon) receive a premium of minus 1%. We do so to reflect that some technologies are implicitly subsidized by financial guarantees, while others are seen as high-risk technologies in the future. However, we could easily adjust those premia in accordance with new findings from financial markets. Finally, mixed with type and technology (sixth column) combines investor specific interest with technology-specific premia. Now have a detailed look at Figure 5. Start with the first three columns in the upper panel.

Observe that specifications depicted here are the same as the fourth column in Figure 2, the third column in Figure 3, and the first column of each cluster in Figure 4 (note that the scales are different). The normal investor with 3% rates increases wind (solar, gas-CCS, nuclear) capacity from 435 GW (98 GW, 0 GW, 52 GW) in 2020 to 1,004 GW (484 GW, 384 GW, 194 GW) in 2050, reflecting a share in total generation of 35% (4%, 0%, 11%) in 2020 or 41% (9%, 19%, 22%) in 2050, respectively. We take normal 3% as references to describe differences to the other investors as relative and absolute changes. The capital cost investor with 5% rates has 48 GW lower (-6 GW, 0 GW, +2 GW) wind (solar, gas-CCS, nuclear) capacity in 2020 but 109 GW higher (+153 GW,+64 GW, -83 GW) less in 2050. The annuity investor provides 254 GW less (-6 GW, 0 GW, +2 GW) wind capacity in 2020 and 381 GW less (-82 GW, +120 GW, + 110 GW) in 2050. Moreover, transfer (storage) capacity is 706 GW (178 GW) in 2050 for the normal investor, but only 497 GW

[12]Giving each investor its own discount factor would distort intertemporal investment decisions within the model.

(199 GW) for the capital cost and 389 GW (112 GW) for the annuity investor. The lower panel demonstrating generation matches those developments. Interestingly, decarbonization is greatest for the normal investor (19 Mt in 2050) although the share of intermittent renewables generation is 5% lower than that of the capital cost investor (56% vs. 61%) that emits 48 Mt in 2050.

Figure 5: Impact of type-specific interest and discount rates, technology premia, and a mixed investor type



Consider the next three columns showing results when accounting for market decomposition and project-specific financing cost. Assuming equal shares of the three investor types leads to weighted discount rate of 5.66%. Accordingly, discounting is loser than in our standard application of 7% and comparable to 5% specifications in Figures 2, 3, and 4. Mixed with type applies the 5.66%

discount rate for evaluating the stream of cash flows of all investor types as well as type-specific interest rates of 3% for calculating the endeffect for the normal investor, 5% for determining the WACC for the capital cost investor, and 9% for computing the annuities. Mixed with technology uses the standard 7% interest rate and applies the technology-specific interest premia of -1% (for wind and solar), 0% (bio-CCS, gas-CCS), and 1% (for remaining technologies). Finally, we combine type- and technology-specific rates in *mixed with type and technology*.

Start with *mixed with type and technology* (sixth column). Wind (solar, gas-CCS, nuclear) capacity grows from 333 GW (119 GW, 0 GW, 54 GW) in 2020 to 1,069 GW (642 GW, 449 GW, 80 GW) in 2050. Generation from wind (solar, gas-CCS, nuclear) makes 42% (12%, 26%, 9%) of total generation in 2050. 2050 storage and transfer capacity are 147 GW or 520 GW, respectively. 2050 CO_2 emissions end with 86 Mt. The differences to *mixed with technology* must be seen as impact of type-specific interest rates. The differences to *mixed with type* are those of technology-specific interest premia. Hence, the impact of type-specific interest rates (technology-specific interest premia) is 4% less (-19%) wind capacity in 2020 and 4% less (-15%) in 2050. Type-specific interest rates (technology-specific interest premia) also impact the final installation of gas-CCS by 1% (-5%) and those of nuclear by -16% (76%). That is, higher interest rates for nuclear power reduce nuclear capacity from 88 to 27 GW in 2050. Final decarbonization is comparable with a higher impact of type-specific rates (+22 Mt vs. +5 Mt). Interestingly, transfer capacity is also fostered by technology-specific premia (also 1% lower rate).

Mixing up investors yields a weighted mix of all investors but comes closest to the normal investor in the long-run. In the short run the annuity shares delay investments so that mixed investors invest more conservative in the beginning but dramatically increase from 2040 onwards. Additionally, accounting for technology-specific premia promotes more wind and solar power in the system at cost of nuclear power. Combining type- and technology-specific rates gives a mix of the two prior discussed specifications but increases capacity in total. In particular, wind offshore and transfer capacity increases so that total wind output is highest from the three mixed specifications.

7. Conclusion

Existing theoretical studies fail to agree on a single investment model. However, a plethora of empirical works advances multiple drivers of investment behavior and decision making. These various drivers are often classified to be related to investor type, project type, and market structure. Thus, in order to reflect investment behavior and depict a closer to real life picture introducing investment type heterogeneity and project (or technology) diversity in bottom-up optimization models is required.

We develop a theoretical framework to account for investor type heterogeneity and technology-specific interest rates in bottom-up optimization models. We apply three different investment cost specifications and varying interest and discount rates to create three stylized investor types that can match existing firms and their specific ownership structures. We combine those different investor types within one optimization framework by enabling different shares of investor types and type-specific interest and discount rates by means of a weighted joint discount factor. We implement this theoretical framework in the EUREGEN model—a European power market partial equilibrium model that optimizes investments, decommissioning, and dispatch for generation, storage, and transmission technologies intertemporally until 2050—to quantify impacts of different investor types, the role of discounting for investment patterns for each investor type, the impact of varying interest and discount rates for each investor type, the role of investor type heterogeneity, and impacts when applying technology-specific interest rates.

We start with disentangling effects stemming from the three different investment cost specifications of the three investor types. The normal investor considers full investment cost in the period of investment, whereas capital cost (applying the weighted average cost of capital, WACC) and annuity (applying annuities) allocate investment cost over the depreciation time of on investment. Assuming a normal investor applying 7% interest and discount rates leads to 362 GW wind capacity (generation share of 29%) in 2020 that increases to 974 GW (40%) in 2050. The capital cost investor with same rates engenders 290 GW (23%) in 2020 and 949 GW (38%) in 2050. The annuity investor provides 206 GW (15%) in 2020 and 759 GW (32%) in 2050. The normal investor invests most into wind power and fundamentally earlier than the capital cost and annuity investor. The capital investor almost closes that gap until 2050, whereas the annuity investor delivers structurally lower wind power capacities or shares, respectively. However, normal and annuity investor invest similarly in nuclear (147 and 140 GW in 2050) compared to the capital cost investor (97 GW). Conversely, the capital cost investor delivers highest gas-CCS capacity (459 GW in 2050) and solar capacity (587 GW) compared to the normal investor (384 GW, 487 GW) and annuity investor (425 GW, 440 GW).

Next, we account for the effects of neglecting discounting. Considering a normal investor applying 7% interest rate but neglecting discounting leads to early wind deployment (446 GW or 35% in 2020). Differences to the case with discounting become even more dramatic until 2035 but level out in the long run. Patterns are reversed for capital cost and annuity investors. Neglecting discounting hampers wind deployment in the short and mid run. However, differences level out again in the long run. Neglecting discounting fosters in general early investments for the normal investor because such a specification places a higher weight on later investment cost. In turn, capital and annuity investors allocate investment cost over time (and not just in the period of investment) and thus show reversed patterns because neglecting discounting in general makes investments more expensive (and thus fosters reliance on existing capacities).

We can derive the impact of diverging financing cost by varying interest and discount rates for each investor type. Higher rates hamper wind deployment at benefits of gas-CCS. Lower rates foster nuclear deployment at cost of gas-CCS when assuming a normal investor. Lower rates also foster wind deployment when assuming an annuity investor. When assuming a capital investor in turn, the magnitude of changes is extreme. Wind and solar deployment for lower rates actually overcome the substitution of gas-CCS and nuclear.

Investor type-specific interest and discount rates reinforce differences across investor types. We apply 3% rates for the normal investor, 5% for the capital cost, and 9% for the annuity investor. Wind capacity increases from 435 GW (386 GW, 180 GW) in 2020 to 1,004 GW (1,113 GW, 624 GW) in 2050 for the normal (capital cost, annuity) investor. Nuclear capacity increases to 194 GW

(112 GW, 84 GW) and gas-CCS capacity to 383 GW (446 GW, 502 GW). Accounting for investor type heterogeneity in markets leads to wind (nuclear, gas-CCS) capacity of 912 GW (140 GW, 428 GW). However, wind power (nuclear, gas-CCS) capacity is 157 GW (-60 GW, +21 GW) higher when applying technology-specific rates but only 45 GW (+13 GW, -5 GW) lower when applying type-specific rates. Thus, the overall investor type heterogeneity significantly affects outcomes of the model. This heterogeneity is largely driven by the underlying investment cost specification as opposed to the final discount and interest rate. However, technology-specific interest rates can, hugely impact final results.

Our analysis reveals one major flaw: as far as we are aware, all the currently available bottom-up optimization models used to derive policy-advice fail to capture the heterogeneity of investors' behaviors, which leads to a substantially different rate and pace of generation capacity development of technologies such as wind, nuclear and gas-CCS. Consequently, this flaw leads policymakers to misinterpret the results. Hence, when modeling energy systems and power markets with a large degree of technological detail, such as is the case in bottom- up optimization models, we need to account for the underlying investor type heterogeneity. Thus, our results confirm that accounting for more differentiated picture of electricity market investment with heterogeneous investor types can provide a starting point for tailor-made energy policies, thereby increasing the efficiency and effectiveness of public policies fostering the decarbonization of power markets.

Alternatively, we need to interpret the results carefully and eventually consult different models with a varying specification of investment cost. Modelers and policy makers need to pay more attention to the role of investment cost specifications, technology-specific financing cost, and overall discount rates. They need to take account of the fact that some investor types are quite resistant to changes in the interest and discount rates, whereas other types are extremely sensitive. Moreover, we suggest to base the modeling analysis on available empirical studies evaluating underlying market-specifics and the key investor types to be accounted for.

Our analysis is subject to some limitations. We focus on the general impact of three types of investors and diverging interest and discount rates. We thus neglect region-specific differences in rates and also region-specific differences in market structures. Moreover, we keep investment cost the same for each investor, whereas those might differ as well. Those limitations can be addressed in future work.

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