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Safeguarding the energy transition against political backlash to carbon markets

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Substantial renewable energy (RE) cost reductions have raised the prospect of a RE subsidy-free era of the energy transition. The envisaged policy cornerstones of this era are carbon markets, which create economic incentives for sustaining further RE deployment. However, this overlooks that exposing RE to market risks and rising general interest rates would result in substantially higher financing cost, which in turn lead to much steeper carbon price paths. The resulting political pressure may provoke a price-depressing regulatory intervention, disrupting further RE expansion. Here, we conceptualize this feedback and infer indicators for the risk of such an intervention. Quantifying these indicators for the European Union, we find that increased financing cost could double carbon prices in the long-term, half the rate of renewable capacity deployment in the next 15 years, and considerably increase fossil fuel plants' profits. This implies a substantial risk of pushback that policy makers should safeguard against.

Renewable energy (RE) technologies are the centrepiece of low-carbon energy transitions. Recent assessments of the competitiveness of electricity from wind turbines[1] and solar photovoltaics[2] suggest that, soon, RE technologies will no longer require subsidies. Governments and industry associations are already responding to this situation by considering to phase out RE support policies in the years to come. For instance, in the UK the future of the RE contracts for differences (CfDs) policy is being questioned[3]. In the EU, legally binding national renewable targets have been abandoned because of a growing opposition against supporting these technologies forever. Instead, it is often argued, that the EU Emissions Trading System (ETS) has matured to the point where it can effectively drive RE investments. In Germany for example, the leading industry association has called for making market-driven deployment centrepiece in the future[4]. Besides its advantage of directly addressing the emissions externality at its source, a key consideration in favour of carbon markets are their seeming effectiveness in achieving climate targets: The cap ensures emissions never exceed a certain level, and in consequence allowance prices automatically adjust to the level required to bring renewables into the market proper.

However, the success of this policy strategy rests on the assumption that emissions trading is indeed fail-safe: once a cap is in place, it will always be reached. Yet, economic research suggests that if prices reach unanticipated levels, this may lead to a retrospective change in the cap[5]. Specifically, if prices rise too sharply, the cap might be revoked[6]. Correspondingly, a certain level may exist beyond which allowance prices are not politically acceptable[7]. Related work in political science has unveiled that the stickiness of cap-and-trade programs depends on political resilience across election cycles, the ability to adapt[8], and specifically in Europe, the politics of ratcheting up[9]. In summary, an important feedback of allowance prices on politics exists, which induces a risk that the cap will be softened. Yet proponents of the above described policy strategy do not take this feedback into account, and how it could endanger the clean energy transition. A major reason for this is the lack of research that analyses the full chain of effects: the impact of renewable support schemes on the costs of capital, how this influences allowance prices, and ultimately feeds back on politics.

Our work addresses this gap by combining economics and political science approaches. First, we conceptualise how alternative allowance price paths for the same cap provoke different feedback on politics. Specifically, we argue that renewable energy investment risk – technically quantified through the discount rate – is crucial for such feedback in emission trading systems since they can lead to a hockey stick-shaped price path. Such a path raises and concentrates the economic adjustment costs of fossil technologies and decelerates the deployment of clean technologies. These costs are indicators for a shifting balance of the political power of respective industries, which is at the core of the risk that the cap will be softened.

We then quantify these indicators for the case of the EU, using the Long-term Investment Model for the Electricity Sector (LIMES-EU). We find that exposing renewables to market risk by phasing out subsidies, and a parallel rise of the general interest rate, induces a substantial risk of softening the cap by mid-2030: allowance prices double by 2055, renewable capacity deployment is delayed eight years by 2035, and fossil fuel plant profits surge to their peak by 2025. Finally, we discuss implications and provide policy recommendation for how to mitigate this risk.

Dynamic feedback from allowance prices on politics

In this section, we conceptualise how the risk of a future softening of the cap arises from the feedback of allowance prices on politics. To that end, we draw on both the political science and economics literature to answer the following questions: First, what are the specific mechanisms that may trigger future softening or strengthening of the cap? Second, which policy settings (e.g. socioeconomic parameters, design features) are crucial for determining the balance of feedback and the likelihood of future softening?

The political science literature argues that policy feedback is an important determinant for policy change and stickiness[10,11]. If positive feedback prevails, the likelihood of policy stickiness increases, i.e. the policy will remain unaltered or might be strengthened. If negative feedback prevails, the likelihood of a political backlash that dismantles the policy, e.g. softening the cap, increases[12,13]. A prominent example for such dismantling is the Spanish feed-in tariff for solar PV, which was radically slashed in 2008 after costs for new installations surged within just a few months[14]. Whether positive or negative feedback dominates depends largely on the costs and benefits a policy creates and how they are distributed[13]. The cost and benefits are strongly related to the industry structure. Structural change, in turn, affects related political coalitions and feedback[15].

For emissions trading, the feedback arises from the allowance price ands its path. According to the economic literature on emissions trading, allowance prices rise exponentially over time at the discount rate[16,17]. This is because firms can bank allowances for future compliance. Hence, allowances practically become a financial asset, whose value grows at the rate by which firms discount the future (discount rate). The level of the discount rate itself is made up of the risk-free interest rate and the specific project risks, notably price risks. Accordingly, the general shape of the price path is determined by these factors. A high discount rate implies that the price starts at a relatively low level but rises more sharply over time. Recent economic work alluding to the problems of such paths[6,7] refers to them as hockey stick-shaped, which we also do in the following.

Combining political science and economic perspectives, as shown in Figure 1, suggests that emission trading is particularly prone to the risk of future dismantling when the discount rate is high. To illustrate this, we make use of two stylised scenarios: “sticky cap” and “softened cap”. The “sticky cap” can be thought of as the scenario underlying the view that the cap is fail-safe, and it is thus the appropriate starting point to make our case. In the early phase, when prices are relatively low, the industry structure is dominated by carbon-intensive fossil-fuel (FF) technologies. The corresponding brown political coalition dominates policy choices. However, with rising prices, green firms benefit because this increases renewable energy (RE) technologies’ competitiveness and generates profits. This, in turn, fosters the growth of green industries. The higher the industries’ profits, the more strongly they engage in a supporting coalition to sustain the policy – similar to the effect of green industrial policies[18]. In parallel, the FF capacity becomes less competitive and is pushed out of the market, and the corresponding brown coalition becomes smaller and smaller, reducing their political influence. Accordingly, in the late phase when prices are high, overall feedback is positive working towards a sticky cap.

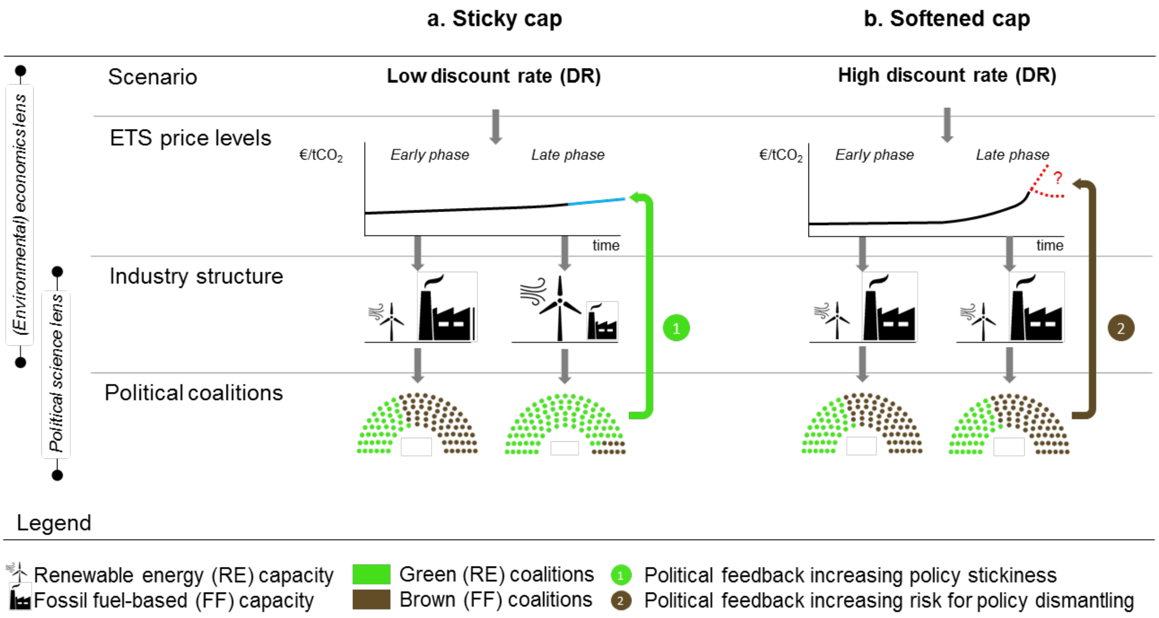

Figure 1: Dynamic policy feedback from allowance prices on politics. a) In case of a low discount rate, prices in the early phase are relatively high, inducing investment that “greens” the industry structure early on. When the late phase is reached, predominantly positive feedback ensures that the cap is sticky. b) The opposite holds for a high discount rate, where negative feedback is predominant in the late stage and softens the cap. Note that adjustment costs (not shown) are smoothly distributed over time in a) and concentrated in the late phase in b).

This is different in the “softened cap” scenario. There because of the higher discount rate carbon prices are initially lower and, therefore, less green investments *in the early phase*, which postpones the transformation of the industry and the related expansion of the green coalition. At the same time, the sharper rise of prices in *the late phase* provokes stronger opposition from the brown coalition because of higher adjustment costs. More specifically, within a short time, considerable FF capacity becomes devaluated[19]. To avoid this, the still-dominant brown political coalition opposes the policy[20]. Since the green coalition is still relatively nascent, overall feedback is negative working towards softening of the cap.

Notably, this situation is only exacerbated when firms anticipate future dismantling of the cap and adapt their demand for allowances and intertemporal trading behaviour accordingly. This is because it effectively leads to a higher discount rate[21]. Accordingly, anticipating future intervention is a sort of self-fulfilling prophecy in the sense that it makes a future dismantling more likely.

To quantitatively analyse specific cases, we propose the following indicators to capture the relative risk of dismantling between different scenarios: First, the intersection of the allowance price paths in the different scenarios marks the onset of the blade of the hockey stick, from which point one can expect the risk of softening to become increasingly severe. Second, the delay in renewable capacity deployment hinders the greening of the industry, and thus prevents the increase in relative strength of the positive feedback from the supporting green coalition. A larger delay implies weaker support. Third, the profit dynamics of fossil fuel-based plants capture the adjustment costs and strength of the negative feedback from the brown coalition. A sharper decline of FF implies stronger opposition.

Application to the EU

In this section, we apply the discussed framework to the EU by quantifying the indicators described above. We choose this region because the shift of the renewable energy policy regime, from subsidies to carbon pricing, is most imminent there. Correspondingly, the investment risk and finance implications of exposing renewables to market risk need to be considered when designing the support schemes[22–24]. Regarding the effect on costs of capital, studies with a narrower scope estimate[25,26] that full exposure to market risk increases financing costs by around two percentage points. However, more recent work also taking regulatory and other risks more broadly into consideration finds a mark-up of around five percentage points[2]. Also relevant for investment risk, the relatively low general risk-free interest rate (IR) may revert to the “old normal”. This would also impair the competitiveness of renewables considerably, because they are typically more capital intensive than brown technologies[27],[28]. As described in the previous section, the decrease in competitiveness due to these two effects implies that the allowance price in the ETS grows faster in absolute terms and becomes more bent in the later phase – that is, becomes hockey stick shaped.

In order to assess the respective risk of a softening of the cap, we employ LIMES-EU, a long-term cost optimisation model of the sectors regulated under the ETS (see Methods for a more detailed description). We want to flag two assumptions that are debatable simplifications with important implications for the interpretation of the model results: First, we assume that agents have rational expectations, i.e. all agents have an identical and consistent vision of the future that is externally coordinated. We discuss in the “Methods” section how this contrasts with other approaches that relax this assumption towards a higher degree of realism, notably agent-based models. Second, future costs of RE technologies are exogenous, i.e. learning-by-doing is not explicitly modelled. Doing so leaves out important effects of energy markets in driving cost degression, for which rich empirical evidence exists[29]. In light of this, and given the importance of future RE cost for the allowance price path, we discuss how this affects our results and findings in the “Methods” section too. We also come back to these assumptions when discussing findings and implications.

Of particular relevance for this work, LIMES-EU also implements the allowance market rules as of the 2018 reform, including the Market Stability Reserve (MSR) and cancellation of allowances. Accordingly, a cushioning of the price bend through the MSR is considered in our analysis. Furthermore, the 2018 reform itself is a proof that EU policy makers do not shy away from retrospectively intervening in the market and changing the cap[30,31]. While this reform only entails a tightening of cap by means of cancelling allowances through the MSR, a future reform might as well entail an intervention in the opposite direction: an injection of additional allowances through the MSR, i.e. a softening of the cap. In fact, Article 29a of the ETS directive already authorizes the regulator to intervene in the market in case of “excessive price fluctuations”.

We use LIMES-EU to analyse two scenarios: The first is a low discount rate (LoDR) scenario resembling the current situation to establish a reference case for comparison. The second is a high discount rate (HiDR) scenario that could arise under the policy choices described above. For the analysis, we break the discount rate down into the general IR and a risk premium depending on the market risk that power plants face: (1) In the LoDR scenario, we assume that monetary and energy policies remain as they currently are. Hence, the general IR remains at the current level of around 0%. FF-based power plants remain exposed to market risk, which in line with recent analysis we assume translates into a cost of capital of 5% (see above). RE plants continue to be supported by dedicated policies, which effectively nullify their market risk exposure[32–35]. Accordingly, we assume a cost of capital of 0%. (2) In the HiDR scenario, we assume that the general IR rises to 5%, and RE policies will be phased out, implying that RE technologies also face the full market risk. Consequently, investments into all technologies – FF and RE – are discounted with a uniform rate of 10%, resembling the market risk premium plus the increased general IR.

Analysing the scenarios using LIMES-EU, we first look at the two allowance price paths (Figure 2) to establish to what extent is the price path more hockey stick-shaped in the HiDR scenario. It should be noted that model prices deviate from current market prices, since our scenarios are based on the current ETS legislation – the cap is set to ensure emission reductions of 43% by 2030 compared to levels. In December 2020 though, the European Council agreed on more ambitious targets, which have already been factored into the allowance price. That said, we find that the allowance price in the HiDR scenario is lower until around 2035 despite the higher cost of capital for renewable energies. Yet, in the long term, the high growth rate of the allowance price gives the price curve a hockey stick shape. Prices rise to around €200 per ton of CO_2 (€/t) in 2055 compared to only around 80 €/t in the LoDR scenario; a sensitivity analysis looking at the effects if a stricter cap and lower RE investment costs is provided in Supplementary Figure 1. The fact that prices in the HiDR scenario surpass prices in the LoDR scenario only after 2035 suggests political pressure to soften the cap will mount two or three decades from now and, hence, seems to be a distant concern. However, looking at the specific indicators, it may turn out that the critical period will start in the nearer future, around 2035.

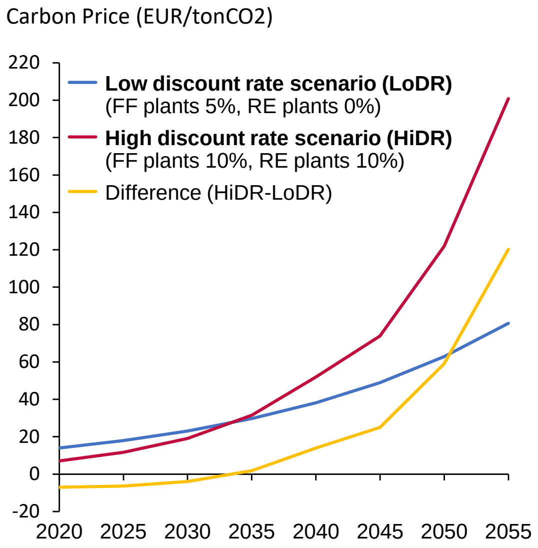

Figure 2: ETS allowance price paths in the two scenarios. Prices are shown up until the year 2055 when, according to current regulations, the ETS cap will reach zero. Price paths intersect in the year 2035, after which prices in the HiDR scenario become markedly more hockey stick-shaped.

Turning to RE capacity deployment, which indicates the strength of the green coalition, we find that lower allowance prices early on and higher costs of capital for RE imply significantly lower deployment

(Figure 3). By 2035, the renewable capacity in the LoDR scenario (1,447 Gigawatt [GW]) is around 535 GW higher than in the HiDR scenario (911 GW). In other words, the level reached in the HiDR scenario by 2035 is already reached around 2028 in the LoDR scenario, implying a “deployment time lag” of around seven years between the two scenarios. To put this into perspective, seven years correspond to approximately two election cycles in most EU countries, implying two occasions for the feedback loop to take effect on the composition of the political coalitions in parliaments and governments. What is more, if only the IR would increase or RE would be exposed to market risk, this would still induce a deployment lag of around five to six years; see Supplementary Figure 2. Hence if just one of the two effects would eventually unfold as assumed in the scenario, the deployment lag would still be substantial.

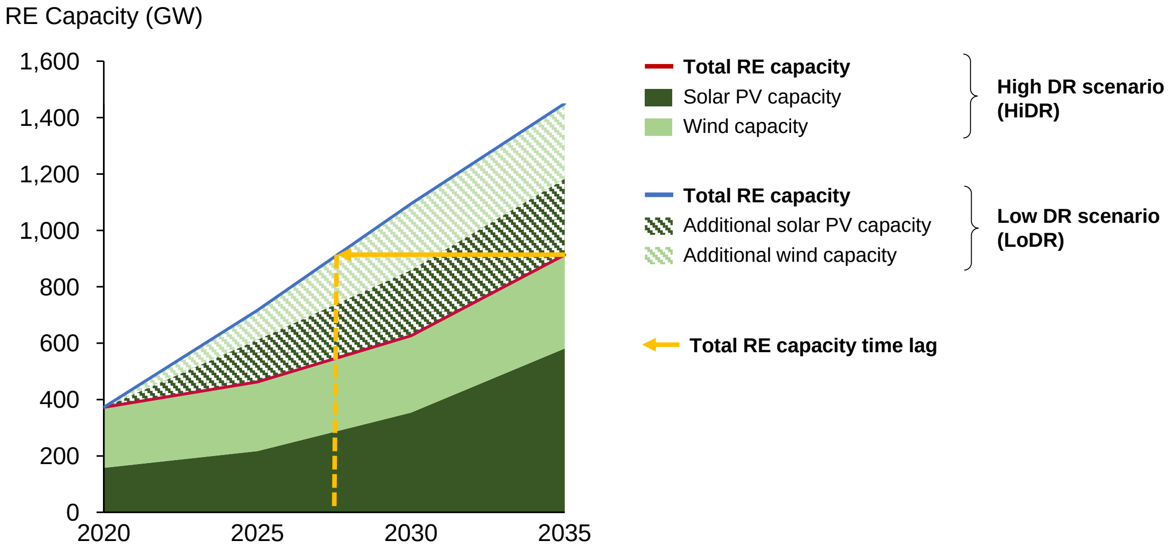

Figure 3: RE capacity deployment in both scenarios. Total RE capacity in the HiDR scenario (red line) by 2035 is equal to the level already reached eight years earlier in the LoDR scenario (blue line), as indicated with the yellow arrow. By 2035, RE capacity in the LoDR scenario is around 535 GW higher than in the HiDR scenario.

Finally, we turn to the third indicator, the profits of fossil fuel-based plants. Figure 4 shows that overall short-run profits are substantially higher in the HiDR scenario compared to the LoDR scenario. Even after 2035, when carbon prices are higher, profits remain higher. The main reason is the deployment lag of renewable energy in HiDR, which increases market shares and, thus, profits for fossil technologies. With a view on how negative political feedback unfolds, the situation is somewhat ambiguous since profits also decline in the LoDR scenario between 2020 and 2030. However, it is unlikely that this will result in a backlash that endangers the cap for two reasons. First, in the period through 2030, allowance prices are still relatively low and do not exceed 30 €/t. Thus, the brown coalition cannot credibly point to a high carbon price burden to lobby against the ETS. Second, since profits are relatively low, the funds that could be used for lobbying are also relatively low in contrast to the HiDR scenario, in which considerably more funds would be available due to the higher and more prolonged profits[36]. More broadly, whereas profits in the LoDR scenario indicate a phase-out trajectory, in the HiDR scenario, profits still rise and thus “peak fossil” still lies ahead. The former pattern discourages lobbying (“lost cause”), whereas the latter encourages it (“playing for time”).

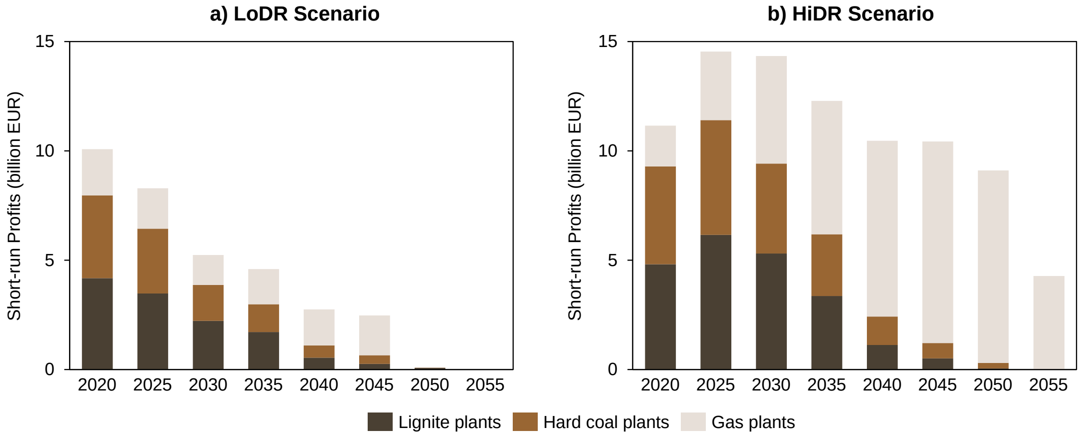

Figure 4: Short-run profits of fossil technologies in both scenarios. a) Profits in the LoDR scenario show a marked phase-out trajectory and are lower than in the HiDR scenario, even through 2035, when the allowance price is higher. b) In contrast, profits in the HiDR scenario describe a trajectory where "peak fossil" still lies ahead and is particularly prone to lobbying.

To summarize, the risk of a softening of the cap is considerably higher in the HiDR scenario than in the LoDR scenario for two intertwined reasons. First, in the HiDR scenario, the green coalition expands much slower due to the delay in RE capacity, and correspondingly, the extant brown coalition remains dominant for a longer time. Second, the brown coalition's lobbying power is fuelled by higher and prolonged profits and the prospect that the fossil phase-out can be postponed. Overall, it seems likely that by mid-2030 the cap will come under pressure: By then, the lag in deployment would have accumulated to eight years and fossil profits would have started to decline, which triggers a political pushback from respective generation asset owners.

Discussion and conclusion

In this work, we highlight the potential risk of political backlash against high carbon prices, which could jeopardize the low-carbon energy transition. Our results have important implications for the upcoming policy reforms driven by the prospect of an imminent "era of subsidy-free renewables". They highlight that the very notion of such an era is misguided, stemming from a simple extrapolation of the current trends of low interest rates and decreasing technology costs. But doing so overlooks that the last decade has been truly exceptional in terms of low and stable interest rates, and conditions are bound to change. Accordingly, the tide may turn against the competitiveness of renewables, which would further be exacerbated by phasing out RE policies. In combination, this could drive allowance prices to a level that triggers political backlash resulting in a softening of the cap.

It is important to point out that this risk is inferred from the results of the quantitative scenario analysis, which are contingent on a number of assumptions. To begin with, it is assumed that agents can tacitly coordinate their investments, and form consistent expectations. Without such external coordination though, the overall investment path would most likely be more volatile and prone to instabilities of the type observed in historical markets, including that assets might become stranded. This may well dampen the effects we analysed, or in extreme cases render them irrelevant. Furthermore, there may be fundamental changes of policy and market design in the future. Notably, the current energy pricing model based on marginal cost might be replaced by other forms of pricing, implying that investment would be driven altogether differently. Finally, and explicitly accounted for in the sensitivity analysis, alternative developments of the interest rate, changes of the cap and RE investments costs also have considerable impact. Regarding the latter, it needs to be emphasized that learning-by-doing of RE technologies and related costs degression are reflected in the respective investment costs assumptions, but not endogenous in our model. This is a considerable limitation given the role these costs play for the level of the allowance price. But since cost degression depends on cumulated installed capacity, which is considerably lower in case of a higher discount rate, it is clear that endogenous learning would only exacerbate the upward bend of the price path and thus the risk of a softening of the cap in the respective scenario.

In face of that, it is all but clear if the scenario we analysed will actually materialise. Nevertheless, we think it is sufficiently tangible to warrant warning policy makers of this risk – also because its impact would arguably have far-reaching consequences for EU climate policy in general. Besides, making aware of the potential risk as such may also be valuable for other jurisdictions with similar policy settings, where a shift away from RE policies is considered and no containment mechanisms are in place that prevent allowance prices from rising steeply.

With a view on how to mitigate this risk, our findings suggest that RE support policies should be continued in their current form. But this would miss an important point: so far, these policies are mostly subsidies intended to stimulate technological learning and market entry. But these goals have been largely achieved by now. Accordingly, we propose to view and design these policies not as “technology subsidies” anymore, but as “de-risking measures” that address the downsides of exposure to market risk and a swing of the general interest rate. Such policies would be more targeted in the sense that the top-up payment would only equal a risk premium. This premium will arguably be lower than current subsidy levels, and could be further reduced through complementary measures such as a carbon price collar that could contain carbon price volatility and thus market risk. In consequence, future RE policies would still come at a cost, but at a lower level than current policies. In that way a negative policy feedback from RE policy costs, analogous to what we analysed for carbon prices, could also be mitigated.

This recommendation primarily addresses general policy design consideration, but more research is needed to support policy makers in creating a toolbox of options to sustain the energy transition and help design the next generation of climate (and RE) policies. First, it is necessary to understand the role of instruments that mitigate power market risks on the financing cost of RE assets. In particular, it is essential to understand the size of cost up-marks going forward, given that continuous expansion of (temporally correlated) RE feed-in will likely affect capture prices and price risk, and also add a quantity risk through looming curtailments. To better understand how these risks can be mitigated, the potential of corporate power purchase agreements, publicly funded contracts-for-difference, and, more generally, novel power market designs for ‘mostly RE power systems’ should be further explored.

Second, we need a better understanding of how carbon price dynamics affect political feedback. In other words, both economists and political scientists should look into the effect size and mechanisms of political feedback triggered by carbon price paths, and investigate how this feedback can be smoothened. One option is to adapt the instrument design of carbon markets, for example through implementing dedicated price controls[37], whose political economy are also not well understood. Another option is complementing carbon markets with instruments cushioning the impact of steep price increases, such as well-targeted side payments (to prevent undue hardships to individuals) or a dedicated investment fund[38].

Third, the influence of the general interest rate needs to be more prominently considered in future analyses. While we currently live in the times of very low interest rates, this is not a given for the upcoming decades – the timespan of the energy transition. Interest rates are a key macroeconomic variable targeted by monetary policy, with central banks using both their reference rates and increasingly ‘unconventional’ measures such as quantitative easing (purchase of bonds) to maintain price stability. Recent research suggests that novel tools such as ‘green quantitative easing’ (purchase of green bonds only) could depart from steering the economy-wide interest rate level only, but allow for lower interest rates specifically for climate-friendly sectors. Such tools are unchartered territory for central banks, and more research is needed to gauge the opportunities and limitations of such policies. Besides monetary policy, fiscal policy could use the current low (oftentimes even negative) interest rates on government bonds to establish a new fund, which could subsidize RE in times of higher interest rates, effectively acting as a hedging instrument. Like above, the consequences and interactions of such policy options remain insufficiently understood.

To conclude, this work highlights that policy makers and researchers should not be lured into thinking that due to falling renewable energy technology costs, the energy transition is now fail-safe and that carbon markets will incentivize RE deployment. Instead, future research needs to provide insights into how to design and/or complement carbon markets to safeguard the energy transition and thus, the Paris agreement targets.

Methods

Numerical simulations for this analysis haven been conducted using version 2.36 of LIMES-EU, a linear dynamic cost-optimisation model with a focus on the electricity sector. It simultaneously optimises investment and dispatch decisions for generation, storage and transmission technologies in five-year time steps from 2010 to 2070. Each year is modelled using six representative days, comprising eight blocks of three hours. The representative days are estimated using a clustering algorithm[39], which allows capturing the short-term variability of supply (namely wind and solar) and demand. The model covers 32 generation and storage technologies, including different vintages for lignite, hard coal and gas. The energy-intensive industry is also covered and represented by a step-wise linear marginal abatement cost curve for each country. The EU ETS is implemented in line with the recent 2018 reform, including the Market Stability Reserve (MSR) and cancellation of allowances. Additional overlapping policies that influence prices by reducing the demand for allowances (coal phase out and renewable energy measures at the EU member state level) are also considered in the model. A comprehensive description of the LIMES-EU model including parameters, equations and assumptions is provided in the documentation available from the model's website[40].

As is typical for optimization models used for scientific analysis[41–43] or assessments by regulatory bodies[44], agents (i.e. investing and producing firms) in LIMES-EU are assumed to have rational expectations as well as perfect information and foresight. In particular, they have information about the future development of core policy and market parameters, including future renewable and fossil technology costs and fuel prices through the end of the modelling horizon. This ensures that actors' expectations about future developments are externally coordinated and thus do not deviate from actual future developments. Usually the results of such models are interpreted as benchmarks, implying that they have limited capacity to predict reality. This is different in other types of optimization and agent-based models, which for example assume limited time horizons, believes instead of expectations, and irrationality instead of rationality so as to better resemble the actual behavior of agents in the markets. Accordingly, these models are suited for forecasts, especially when overall structures do not change and estimated behavioral parameters remain stable. As a case in point, short term price formation in the EU-ETS is particularly hard to explain with standard environment economic theory, and much better with (behavioural) finance[45]. All this need to be kept in mind when interpreting the model results, in particular when making judgements about how likely it is that the scenarios will materialize.

Furthermore, we consider induced innovation in the form of learning-by-doing for RE technologies, but only exogenously by inferring cost assumptions from the ReMIND model that incorporates such learning on the global level; also see the LIMES-EU model documentation. The particular values are provided in Table 1. The reason why we do not endogenize learning is two-fold: The first is solvability. LIMES-EU is a linear optimization model, and embodying learning rates require using power functions. Accordingly, we would not be able to solve the model anymore. The second is that many studies have estimated learning rates based on global cumulative deployment, especially for solar PV that experiences the strongest cost degression. In face of that, we draw on the results of the ReMIND model (see above) as a "fall back".

Year	Wind Onshore	Wind Offshore	Solar PV
2020	1550	4075	700
2025	1500	3800	600
2030	1450	3500	550
2035	1425	3350	500
2040	1400	3175	475
2045	1375	3000	450
2050-2070	1350	2825	425

Table 1: Default assumptions for RE investment costs [€/kW] in the LIMES-EU model.

In contrast, fossil fuel (FF) technologies are assumed to be mature and their investment costs remain constant at the following levels: 1.800 €/kW for hard coal plants, 2.100 €/kW for lignite plants, 900 €/kW for gas combined cycle plants, 400 €/kW for gas turbine plants, and 400 €/kW for oil plants. Notably, fossil investment costs at this level imply that solar PV will achieve cost parity with hard coal by 2025, depending on regional solar energy potential and implied hard coal capacity factor. As soon as cost parity is reached, investment dynamics are determined by the competition between new RE plants and existing FF plants, whose investment costs are sunk. That is, new RE plants are built to the extent their annualized investments costs outcompete the annual operational costs of existing FF plants. Respective FF plants are closed down.

Finally, the main mechanism driving the results is the effect of (future) carbon prices on investment in RE capacity, and relatedly on disinvestment in fossil capacity that might be replaced. In LIMES-EU, as in actual markets, this happens through the electricity price: The price of electricity is equal to the marginal costs of production, which include the carbon price as a cost factor; see equation (1) in the model documentation[40]. When making investment decisions, agents in the model anticipate future electricity prices and thus, indirectly, also carbon prices. Hence carbon prices affect the profitability of RE investments vis-à-vis fossil plants. This mechanism is in line with actual bidding behaviour in electricity markets, and backed by empirical evidence. For example, empirical analyses find that carbon prices are passed through to electricity prices completely[46], and that future prices in the German electricity market are mainly driven by carbon prices and fuel prices[47].

The different allowance price paths we analyse in the LoDR and HiDR scenarios are endogenous to the model, since it contains an implicit representation of the allowance market in line with the price formation mechanism described in Section "Dynamic feedback from allowance prices on politics". Correspondingly, firms also anticipate that a higher discount rate leads to a more hockey stick-shaped allowance price path. The risk of a dismantling of the cap that may result from this is not endogenously considered in the model analysis though. The reasons we refrain from doing so are analytical tractability and model complexity. More specifically, we know from economic theory[21] that modelling such a risk explicitly implies a (non-constant) discount rate that rises over time, which would make the model very hard to solve. However, from theory we also know that a rising discount rate only makes the hockey stick more pronounced, i.e., if anything, it would amplify the risk. In any case, our intention is not to assess how the risk itself would change investment behaviour, but whether investment behaviour in the HiDR scenario makes such a risk more likely in the future in comparison to the LoDR scenario. For that, we derive indicators drawing on theoretical considerations and empirical evidence, which we quantify using the model results. Based on these indicators, we subsequently argue why this risk increases with risk premia for renewables and a higher general interest rate (HiDR scenario).

With a view on how we represent higher (technology specific) market risk and a higher interest rate, like all optimisation models of this type, LIMES-EU only allows for a single discount rate. Accordingly, technology-specific discount rates need to be implemented indirectly. To this end, we convert the market risk premium (δ [%]) into a monetary value expressing the net present value of the technology-specific risk premium (RP [€/MW]) and deduct it from the model's default investment costs. For this purpose, we make use of the fact that LIMES-EU results resemble a competitive market equilibrium, i.e. the NPV of all investments equals zero. To determine the risk premium, we define

$$(1)\ NPV_A = -IC + \sum_t \frac{1}{(1+r+\delta)^t} CF_t = 0 \implies IC = \sum_t \frac{1}{(1+r+\delta)^t} CF_t$$

$$(2)\ NPV_B = -(IC + RP) + \sum_t \frac{1}{(1+r)^t} CF_t = 0 \implies IC + RP = \sum_t \frac{1}{(1+r)^t} CF_t$$

where CF_t are the cash flows from selling the plant's production and IC are the investment costs. Assuming that the cash flows are constant over time, the risk-adjusted investment costs ($IC + RP$) can be derived by expanding the right-hand side of (2) and inserting (1), which leads to the following expression:

$$(3)\ IC + RP = \frac{IC \sum_t \frac{1}{(1+r)^t}}{\sum_t \frac{1}{(1+r+\delta)^t}}$$

Our assumptions for the technology-specific risk premium (RP), which comprises market risk and general interest rate, are based on the following empirical evidence: Regarding the interest rate, we assume it is 5 percentage points (pp) higher in the HiDR scenario compared to the LoDR scenario. Effectively, this would mean a return to interest rates prior to the financial crisis in Europe[28], which, given prospects of rising inflation in the US and Europe (the 2% inflation target of the European Central Bank was surpassed in May 2021) seems a plausible development. Regarding the RE market risk premium, we assume a value of 5 pp in the HiDR scenario to account for uncertainty in electricity market prices. This assumption is based on a recent study by the International Energy Agency[2], which estimated the premium at 4.6 pp (3.3 pp – 5.3 pp, solar PV, nominal after tax), with the estimates derived from a variety of sources, including financial markets data, expert interviews and reverse engineering of successful auction bids.

Data availability statement

Raw data for figures 2-4 is available from https://doi.org/10.5281/zenodo.5128391. Data for core model assumptions (investment costs, fuel costs, etc) is provided in the LIMES-EU documentation (see “Methods”).

Code availability statement

The LIMES-EU model code is available upon request from the authors.

Conflict of interest

All authors declare no conflict of interest.

Author contributions

M.P., S.O., O.T., T.S.S., B.S., F.E. and O.E. developed the research idea and the conceptualization. S.O., together with M.P. and O.T. conducted the model analysis. M.P., S.O., O.T., T.S.S., B.S., and F.E. interpreted the results. M.P., together with O.T., B.S., F.E., and T.S.S. wrote the paper. M.P. and T.S.S. secured project funding.

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