CENTRE FOR ECONOMIC POLICY RESEARCH

CEPR

February 2025

Contracts in the reform of the EU electricity market[1]

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1 FROM WHOLESALE PRICES TO CONTRACTS

When industrialised countries began to liberalise their electricity systems some 30 years ago, the effects of burning fossil fuels on the climate were only just beginning to be discussed (specifically, the Rio Summit was held in June 1992). The market model that was set up was adapted to dispatchable power plants burning fossil fuels. Remunerating producers on the basis of the energy they put on the wholesale market in real time seemed to provide sufficient incentives for efficient production and investment decisions.

This market model, still in use now, is regulated. To prevent large producers from exercising market power, authorities cap energy prices at the cost of reducing operators' profits during peak periods. This creates a 'missing money problem' when the cost of generation capacity is not covered (Joskow, 2007) and raises concerns about under-investment in generation plants. This concern is now particularly high, given the investments in intermittent sources of energy.[2] Solar and wind power, for example, require back-up peak capacity to replace them when they are not producing. Such back-up plants must be remunerated in addition to their output so as to be viable given the cap on spot prices. This in turn calls for 'capacity mechanisms'.[3] Overall, to reconcile reliability with a higher penetration of renewables, the liberalisation of the electricity industry has evolved from a market-only paradigm to a mixed system with a dose of regulation and central planning through capacity procurements (Borenstein et al., 2023).

The 2024 reform of the European Union's electricity market (Regulation 2024/1747 and Directive 2024/1711) adds another layer of complexity with the development of long-term contracts, such as power purchase agreements (PPAs) and contracts for difference (CfDs). PPAs are physical supply contracts between sellers and buyers of electricity, in which the two parties agree on a price in advance and, at the date specified in the contract, inject and withdraw (respectively) the agreed-upon volume. CfDs do not specify any electricity delivery; rather, they are a pure/unbundled insurance/financial

1 This policy note has been funded by the Agence Nationale de la Recherche under grant ANR-17-EURE-0010 (Investissements d'Avenir program). The TSE Energy & Climate Center receives financial support for its research; a list of partners of the Center is available here.

2 In energy transition, governments have used feed-in tariffs (long-term contracts with above-market prices) to encourage investment in renewable energy sources that are intermittent, such as solar and wind power.

3 In the European Union, energy is one of the areas of shared competences between the EU and its Member States. Member States exercise their own competence where the EU does not exercise, or has decided not to exercise, its own competence (Article 194 of the Treaty on the Functioning of the European Union). In this context, on 1 January 2017 France adopted a capacity market as the mechanism to complement electricity sales.

contract in which the seller (resp. buyer) pays the difference between the market price and the strike price if positive (resp. negative), thereby effectively fixing the transaction price in advance. The CfD contracts defined in the reform, however, differ from the standard CfDs; here, the monetary transfers are triggered by/conditional on actual power delivery. This hybrid contract (neither purely physical nor purely financial) will be called 'conditional-CfDs', or 'c-CfDs' for short.[4] Importantly, we will show that c-CfDs will provide suppliers with the wrong incentives.

In this Policy Insight, we discuss the challenges facing the organisation of the electricity market through the lens of the EU's market reform. We successively address two goals that the electricity market should consider: first, ensuring the optimal dispatching of existing electricity generation at the lowest cost (Section 2); and second, fostering efficient and reliable investment in new generation to reach the EU's decarbonisation targets (Section 3). We then investigate the challenges associated with developing long-term contracts for electricity generation in Section 4. Section 5 provides concluding remarks.

2 SHORT-TERM EFFICIENCY

In the short term, the cheapest sources of electricity production (in terms of social cost, including environmental costs) should be called upon first, and be utilised for their most productive uses on the demand side. Because the spot wholesale market and dispatching according to the merit order create a relevant price signal of current resource scarcity,[5] they respond effectively to this objective. Appropriately, their relevance has been reaffirmed in the agreement signed by European energy ministers on 17 October 2023. Yet, in some countries – particularly France – citizens and politicians are unsure as to why their electricity prices are so high (despite its relatively inexpensive production costs), when expensive natural gas represents only a small proportion of the primary energy used in French electricity generation.

The key to understanding the high sensitivity of electricity prices compared to that of gas is to note that gas is often the 'marginal' source of energy. When 1 extra MWh is needed for European consumption, this additional MWh will most likely be produced by a gas turbine, as decarbonised plants (renewables and nuclear) are already operating at capacity. But why should France 'import' European prices of €150/MWh, which was the variable cost of producing electricity from gas,[6] when the accounting cost[7] of its existing nuclear fleet, which provides most of its generation, is around €60/MWh? To answer this question, suppose that the price in France is administratively maintained at €60/MWh, and that the marginal French manufacturer is willing to pay €70 for this MWh. The MWh should not be dispatched to this manufacturer, as €70 lies below its opportunity cost. The cost of this MWh for society is the European price of €150, because it could have been resold at this higher price instead of being consumed. The outcome of this regulation is a shortfall of €90 for France, which could have more than compensated the industrial customer for their loss when they refrain from consuming (€70 – €60 = €10), leaving €80 for the community. Thus, the proper price is the price determined by the intersection of the marginal cost curve and the demand curve, which reveals the true value of electricity (€150/MWh in our example). Aligning French prices with French production costs would be misguided.

4 Note that the distinction between PPAs and CfDs is sometimes made not based on physical versus financial transactions but rather on the involvement of a third party (e.g., public authorities, such as the UK's Low Carbon Contracts Company Ltd) in CfDs. In fact, third-party intervention is not mandatory. CfDs can be private bilateral contracts like PPAs, although Regulation 2024/1747 mentions that the counterpart is "*usually a public entity*" (paragraph 76).

5 Here we make the assumption that bids reflect the social cost of carbon embodied in production, and so climate and other pollution costs are properly internalised in the price signal through emission pricing, such as a carbon tax or an emission trading scheme.

6 Gas prices on the European wholesale market exceeded €150/MWh in the summer of 2022. They were around €50/MWh in October 2023.

7 The accounting cost includes the operating cost (marginal cost per MWh) and the cost of extending the life of existing power plants, given that the construction cost has already been gradually paid off.

While the wholesale market efficiently allocates scarce power resources in a competitive market, incumbents who are dominant in their zonal market should not be able to exercise their market power. Such spatial dominance could lead them to hold onto unused capacity during periods of tension between supply and demand, when electricity prices are already high. Fortuitously, there are various ways of limiting the market power of incumbent operators. In addition to ongoing monitoring by national regulatory agencies under the European REMIT rules,[8] the three *least intrusive* approaches to limiting incumbents' incentives to manipulate market prices are:

- **Opening up domestic electricity markets to international competition**, which could be facilitated by increasing cross-border electricity transit capacity.
- **Forcing incumbents to sell electricity in forward markets**. While cross-border competition has a clear competitive effect, it is perhaps less obvious that forward sales also contribute to a healthier market. This is an idea that has been put into practice several times in Europe and the UK: raising prices by withdrawing capacity from the spot market is less profitable for a dominant operator when most of its generation capacity is subject to a previously fixed price. Indeed, price rises will only benefit the company for the remainder of its production sold on the spot market (Allaz and Vila, 1993; Green-Newbery, 1992). Forward sales weaken the market power of the dominant operator and will, therefore, not occur spontaneously. This is why regulators sometimes force companies to sell part of their production forward (for example, through long-term sales contracts, as we will see in Section 4).
- **Increasing the elasticity of demand** through the use of home automation, smart meters, batteries and other energy storage systems, and the installation of decentralised production units, which limits the benefit of price manipulations.

Regulatory interventions to force forward sales, however, must (a) not prioritise inframarginal units (low marginal cost/must-run plants are less likely to be withdrawn from the market); and (b) avoid creating opportunities for rent-seeking by capacity buyers (to this end, generation capacity must be sold forward by an incumbent operator at the market price). From both points of view, the policy preferred by the *Accès Régulé à l'Electricité Nucléaire Historique* (ARENH) in France, which forced EDF to sell part of its nuclear energy to retailers at the regulated price of €42/MWh when the market value of this resource was much higher, cannot be economically justified.[9] The nuclear rent could have gone either to EDF (and, therefore, in part to the French state, which is now EDF's sole shareholder), or, if EDF itself were considered to be undeserving of the rent, directly to the French state. Under no circumstance should public money have been transferred to private retailers. The official motivation was that this would create 'competition' for the incumbent operator, which was clearly not the case: a fixed quantity of nuclear electricity put on the grid has the same impact on the spot price of the electricity market, whether the electrons are labelled EDF or are under another retailer's name. This was an error to create the impression of competition via ARENH.[10] It would have been better to stimulate the development of competitive long-term contracts that more effectively limit the risks of the abuse of a dominant position on the wholesale market and incentivise new capacity, instead of redistributing the rents on the existing market.

8 Since 2011, the "Regulation on Wholesale Energy Market Integrity and Transparency" (REMIT) prohibits insider trading and market manipulation. It also obliges market participants to register with their National Regulatory Agency, to report wholesale energy market transactions and to publish insider information. The revised REMIT took effect on May 7, 2024. It expanded the scope of regular surveillance by the EU Agency for the Cooperation of Energy Regulators (ACER).

9 Fortunately, this ineffective, heavy-handed policy will come to an end in 2025, but to date, we do not know what it will be replaced by.

10 At the very least, the government should not have administratively set the price of access to ARENH. It would have been more efficient to resort to an auction (Ambec and Crampes, 2019).

However, at the time ARENH was created, the European Commission had a very negative view of contracts, which it saw only in terms of blocking the entry of challengers.[11] Yet, the general role of contracts is to introduce some security in the relationships of co-contractors by limiting opportunistic behaviours. The resulting mutual commitment allows the buyer and the seller to share risk and to invest in consumption and production equipment. During the 2021-2022 energy crisis, the European authorities revised their negative judgement. As we explain in the next section, these authorities now consider that long-term contracts are 'welfare enhancing', because they "*provide long-term price stability for the customer and the necessary certainty for the producer to take the investment decision*" (Regulation 2024/1747, recital 28).

3 INVESTMENT IN NEW GENERATION, RENTS AND ELECTRICITY PRICES

In Subsection 3.1, we examine three interdependent questions that require further thought: Are the demand and supply of electricity buyers and sellers flexible enough for them to reap the full benefits of the spot market? Can spot prices serve as a guide to investment in consumption and production equipment? Do spot prices allow electricity producers to balance their books, and can domestic and professional consumers afford them? The following two subsections explain why physical and financial contracts promoted in the EU by Regulation 2024/1747 can efficiently complement the wholesale market if they are well designed.[12]

3.1 Wholesale market imperfections

3.1.1 Imperfect adaptation to short-term price volatility

Electricity is not (yet) a storable commodity. Consequently, spot prices fluctuate wildly in response to temporary supply and demand shocks. Yet, for technical and/or behavioural reasons, consumers react very little to daily increases in electricity prices. This lack of flexibility reduces their wellbeing in contrast to a situation where they could adapt their consumption. Similarly, production lines may not be flexible enough to take advantage of price variations. With the deployment of ever-more-sophisticated smart meters (for households) and more flexible production technologies (for business users), nevertheless, retail and business users will be able to take advantage of price fluctuations by benefiting from low prices while reducing the impact of high ones. The development of electricity storage – which is encouraged by prices that truly reflect scarcity – will also contribute to the smoothing of prices.

3.1.2 Absence of signals for investment

So far, we have focused on the spot market and its price as a signal of current scarcity. In the longer term, maintenance and investment decisions need to be guided by a price signal that reflects the expectations of electricity scarcity in the future. This is particularly important as the uses of electricity increase rapidly with green mobility and green heating. The investments required in the near future – both upstream (low-carbon electricity production and transmission) and downstream (decarbonised electricity consumption) – will be substantial,[13] and all players will need reliable price signals. This is particularly the case for investors in green electricity generation, who require reliable information about the return on their investments if they are to take up the challenge. This emphasises the critical nature of the regulatory framework and its credibility.

11 For an illustration, see "Commission decision relating to a proceeding under Article 102 of the Treaty on the Functioning of the European Union and Article 54 of the EEA Agreement", which explains how the Commission obliged the French producer EDF to shorten the duration of its contracts with large industrial consumers in 2010.

12 Recall that in the EU, contrary to a "Directive" that must be transposed into national law before it is applicable in the member state, a "Regulation" is binding in its entirety and directly applicable in all member states as it enters into force. By its Article 3, Regulation 2024/1747 entered into force on 16 July 2024.

13 "*The Net Zero Emission Scenario requires a large increase in investment in clean energy. … Electricity generation from renewables sees one of the largest increases, rising from USD390 billion in recent years to USD 1,300 billion by 2030*" (IEA, 2022).

3.1.3 Keeping prices affordable and covering costs

Besides the investment imperative, another key challenge for authorities is to avoid a large impact of uncertainty on the financial strength of agents – in particular, financially fragile agents, where the aggregate risk cannot be avoided, but it can be shared through an insurance mechanism. Fluctuations may not be temporary – with low prices compensating high ones – and shocks may have lasting effects, such as the war in Ukraine, the decommissioning of nuclear power in Germany, or tomorrow's need for generation and transmission network reinforcement. Long-term uncertainty about the average price of electricity requires careful risk management by companies and households: poor households may not be able to afford electricity price hikes, and businesses may lose their international competitiveness, face financial hardship, or face bankruptcy. Conversely, low prices jeopardise the financial health of power-generating companies, while the anticipation of low prices slows down investment, creating shortages in the future.

3.2 Power purchase agreements

The need to protect against long-term price uncertainty clearly calls for the signing of long-term insurance contracts. To stabilise their balance sheets, buyers and sellers of electricity can agree on the price of electricity delivery in advance. This is referred to as a 'physical contract' (requiring guaranteed access to the corresponding network between the points of withdrawal by the buyer and injection by the seller). These physical contracts are named power purchase agreements (PPAs). Under a PPA, the volume specified in the bilateral contract (between buyer and seller) is effectively supplied and withdrawn on the power grid. The reciprocal benefits brought by a PPA to its signatories explains the wave of deals seen in the United States in 2024 between operators of large data centres and power producers using nuclear energy (including small modular reactors; see Ambec and Crampes, 2025). The agreements enable the operators to secure their energy supply and the power producers to obtain financing for their investments.

EU Regulation 2024/1747 calls for the development of "transparent" markets for PPAs. Transparency requires standardised templates (designed under the control of the EU's Agency of Cooperation between Energy Regulators (ACER); see Article 19b) that may leave insufficient flexibility in contract design. Indeed, it may be in the interest of electricity-intensive companies to negotiate a purchase contract (individually or collectively) with producers that corresponds exactly to their needs; an agreement where the conditions do not perfectly comply with the official model. For example, Exeltium, a purchasing consortium established in France (May 2006) by seven of the country's biggest electricity consumers[14] and with the backing of the public authorities and banks, currently issues invitations to tender for the supply of blocks of electricity over the long term. This deal was accepted by EDF as it helped the main French electricity producer to plan the new Flamanville nuclear power unit. The EC Directorate-General for Competition modified the Exeltium rules: member companies were allowed to opt out of the deal at year ten, and every five years thereafter; and resale restrictions were lifted. Whether this regulatory intervention is justified by competition concerns or not, it illustrates the difficulty of drawing bespoke contracts. In any case, the most electricity-intensive companies are seeking new long-term electricity contracts that could include partial financing of new nuclear power plants, in return for reserved capacity (UNIDEN, 2023).

3.3 Two-way contracts for difference

A contract for difference (CfD) does not specify any real electricity delivery, and simply sets a nominal quantity that forms the basis for pure monetary transfers between contract participants. Any quantity injected into the grid by a producer is

14 The founding members were Arkema (TOTAL's chemicals subsidiary), Air Liquide, Alcan, Arcelor, Rhodia, Solvay and the Finnish paper manufacturer UPM. They were later joined by some 20 other companies.

remunerated at the market price; similarly, the buyer on the other side of the contract pays the market price if he or she decides to consume. Thus, as is the case for spot markets, there is no obligation to inject or withdraw any specific quantity, including the nominal quantity specified in the CfD contract. The nominal volume only serves as the basis by which to compute financial transfers, as the contract is a mutual insurance or financial contract. The seller receives a payment from the buyer that is equal to the difference (on this volume) between the contract price and the market price, if the latter is smaller. Symmetrically, the buyer receives from the seller a unit payment equal to the difference between the realised market price and the contract price on this volume, if the latter is smaller. So, if the volumes actually injected and withdrawn correspond to the volume specified in the contract, both sides are fully protected from price risk. Furthermore, as actual wholesale market transactions are totally disconnected from the CfD contract, they are efficient: the seller puts the quantity of electricity on the market that is profitable to produce at the market price, and symmetrically, the buyer consumes if and only if their willingness to pay exceeds the market price.

As suggested above, a CfD contract volume has a double dividend roughly equal to the production volume that is contemplated for the plant. First, the producer is insured on average; it is fully insured if supply is inelastic and *relatively well insured* if some adaptation of production to market conditions is desirable. Second, forward sales curb market power, if any. Withdrawing electricity capacity from the spot wholesale market raises prices, especially in periods of scarcity where the supply response is weak. However, if most of the electricity sold by the producer is the object of CfDs, raising the spot price is not very profitable, even for a dominant electricity producer. The price increase is then compensated for by a payment from the producer to its counterpart in equal magnitude for the CfD volume.

In fact, the EU's market reform promotes both types of long-term contracts (PPAs and CfDs). However, the notion of CfD contracts in the reform differs from the standard contract in the economics literature. It resembles a CfD, except that the insurance component is triggered by physical delivery. For this reason, we call 'c-CfDs' the *EU version of the CfD*, where the 'c' refers to the *conditionality* of the agreement, which is applied only if physical delivery occurs. This mix of financial and physical features is an inferior design as it fails to disconnect the insurance and the dispatching sections of the agreement.

The contemplated version of a c-CfD involves the government as the buyer of electricity. In such a c-CfD, the government compensates the producer for lost revenue when the market price is lower than the strike price (the producer's remuneration is fixed in advance by a reference price known as the 'strike price'). Conversely, the producer pays the difference when the market price is higher than the strike price. So far, so good. Unfortunately, and in contrast to an ordinary CfD, these monetary transfers only occur if the producer actually puts the corresponding volume on the market.

While c-CfDs reduce the risk faced by investors in new electricity plants without jeopardising the existence of the wholesale market, the fact that the producer's remuneration is contingent on delivery implies that power plants could be called upon to produce, even though they are not the cheapest. Conversely, electricity may not be dispatched as the production cost lies below the market price. To illustrate this, suppose an electricity producer signs a c-CfD with the state with a strike price of €60 per MWh. If the market price is €40 per MWh, the state will pay the difference of €20 per MWh. If it rises to €80, the producer will have to pay back €20 per MWh. As a result, the producer earns €60 per delivered MWh, regardless of the realised wholesale market price. It is, therefore, in its interest to produce electricity if the strike price exceeds its production cost. If this occurs, it will bid the lowest possible price in order to be certain of being called into dispatching (which is built by stacking production bids in ascending order).

If the market price is €40 per MWh, a plant with a production cost of €50 per MWh should not operate if efficiency is to be achieved. Yet, when the c-CfD strike price is €60 per MWh, it bids below €40, is called in on merit, and pockets a margin of €60–€50 = €10 per MWh. Symmetrically, if its production cost is higher than the strike price, it would lose out on every MWh produced. Therefore, it bids an amount high enough not to be called. If its cost is €70 per MWh, it does not produce so as to avoid making a loss, even if the market price rises to €80 per MWh. The conditionality of the insurance contract on actual delivery thus creates an artificial wedge between market price and plant revenue from generation, and leads to inefficient dispatching. In this respect, by fully insuring the producer against price variations, a c-CfD functions like another form of conditional contract; that is, the *guaranteed feed-in tariffs* for renewable energies. These tariffs have contributed to the occurrence of episodes of zero or even negative prices (Ambec and Crampes, 2017). Indeed, in the case of feed-in tariffs, producers have continued producing in periods where there is a glut of electricity, as they receive a relatively high price for electricity that is useless or even detrimental.

4 THE CHALLENGES FOR DEVELOPING A LONG-TERM CONTRACT MARKET

The development of physical and financial contracts should improve the efficiency of medium- and long-term exchanges in the electrical industry. Nonetheless, there are still obstacles to this development (Subsection 4.1), and public authorities will have to intervene to overcome them (Subsection 4.2).

4.1 Obstacles to signing contracts

In practice, there are very few insurance contracts in the absence of regulation, for three main reasons: first, the anticipation of public aid in the event of difficulties; second, the lack of liquidity in the market for futures; and third, an insufficient supply of insurance. Specifically:

1. **Anticipation of state bailouts, implying limited insurance demand**. The first reason for the lack of insurance contracts is the buyers' and sellers' expectations of government intervention in the event of solvency problems. Electricity consumers (households, industry, utilities) expect a 'soft budget constraint'; that is, a government bailout. When the price is high and powerful political lobbies have not covered themselves enough through forward sales/purchases, the government is under pressure to bail them out. This bailout makes sense ex post but generates the wrong incentives ex ante.
   Government bailouts – which may more broadly benefit banks, industry, farmers, and so on – are not usually announced ex ante. In fact, regulators often state that they will not bail out uninsured players, although they may renege on their commitment when facing a fait accompli. In the electricity market, the recent tariff shields were decided ex post, after the shock occurred.

   The electricity market is not unique in this respect. For example, farmers who refuse to insure themselves against price or production contingencies rely on a gesture from the state in the event of a problem. Their strength lies in their numbers. A single uninsured farmer would not be listened to by the state, whereas a large number of farmers in this situation are more likely to be heard. Similarly, the individual who builds their house next to an airport will not prevent the expansion of that airport. Conversely, 10,000 individuals who do so may have more effect and be able to block any expansion. Economists call this phenomenon a problem of 'collective moral hazard'.

   Some ex ante promises of bailouts, however, also exist in the electricity sector. An example is the option for French electricity consumers who have a contract that states that the price they pay is indexed on the spot price and that it will switch back to EDF's regulated tariff if wholesale prices rise. Similarly, retailers benefit from a free option under ARENH; a policy instrument they turn to only when wholesale prices increase.

The appropriate remedy for unwanted ex post bailouts is to mandate ex ante insurance. In the electricity context, this consists of forcing a large proportion of electricity generation capacity to be bought/sold on the forward market or to hedge it with a long-term financial contract. This is easier said than done, however, due to:

2. **The lack of liquidity on the futures market**. A vertically integrated company (for example, an electricity producer that is also an electricity retailer) is 'naturally hedged' and therefore has little interest in participating in the futures market, which in turn reduces its liquidity. Once again, compulsory participation would help avoid excessively low liquidity; and
3. **The limited offer of insurance**. The solvency of insurers can also be an obstacle to the conclusion of forward contracts. Uncertainty about their ability to meet their commitments can hinder such contracts. This may occur in the same way that a bank can be excluded from the interbank market when information about its balance and off-balance sheet activities is leaked and concerns are then raised about its ability to repay loans or honour obligations in the derivative markets. Monitoring the solvency of both sides of the long-term markets or the use of margin calls may help foster such markets. Solvency regulations may also prevent specialised companies from developing their portfolio of insured contracts.

4.2 Some basic regulations

Regulatory changes – in particular, the updating of prudential regulations – and changes in practice are possible and desirable in order to remove these three types of limitations discussed above.

The EU's market reform encourages strongly – but does not mandate – the two types of long-term contracts previously mentioned (PPA and c-CfD). The market's conditions for c-CfDs create wrong incentives on the supply side. Furthermore, if member states are authorised to conclude c-CfDs for new decarbonised installations (renewables and nuclear), contracts concerning investments to upgrade and extend the life of existing nuclear power plants will be subject to more restrictive conditions and controlled by the European Commission. In the EU legal framework, CfDs signed with a public entity are state aid likely to distort competition, as clearly established by the European Commission (2014). Therefore, these CfDs must be notified to the Commission, which will decide whether to raise objections to the envisaged CfD allocation plan. For example, in July 2024, the Commission approved €1.5 billion French state CfDs to support sustainable biomethane production in order to foster the transition to a net-zero economy (European Commission, 2024).

5 CONCLUDING REMARKS

We shall conclude with the 'elephant in the room'. In recent years, households have been protected by a tariff shield that has been extremely costly to public finances. These protective measures could have been less costly if they had targeted only the poorest households. We must therefore prepare for the future so as to avoid increasing public deficit further should similar conditions arise. The EU's market reforms highlight that two-way c-CfDs would provide an additional source of revenue for member states levied on producers in case of price spikes. This extra revenue could then be passed on to the final consumers. Regulation 2024/1747 (recital 43) recommends to "*favour vulnerable consumers and customers affected by energy poverty*" without imposing any specific allocation rule. It also acknowledges that, in the event of a new and sustained surge in prices, governments can adopt tariff shield-type measures as part of a crisis mechanism (recital 8). The economic rationality of the tariff shield remains to be proven. Further, the absence of consumer reactivity to price variations – at least in the short term – can be invoked (Gerlagh et al., 2022), but this does not suppress the need for ex ante insurance instruments (such as long-term contracts). We must prevent collective moral hazard in the form of a wide-scale lack of insurance and the associated *fait accompli* motivating tariff shields (on the consumer side) and bailouts (on the corporate side).

Which brings us to our final point. The fight against global warming, geopolitical tensions, the unsettled social acceptability of most means of production, and technological uncertainty all create a significant macroeconomic risk. With all things considered, someone has to bear this risk (which many people prefer to ignore). Furthermore, in a world where investment must guarantee a minimum level of profitability to attract financing, not all of the risk can or should be placed on electricity producers, which means that consumers – both retail and industrial – must also be exposed to risk. Alternatively, they must sign up to insurance contracts (through their suppliers in the case of households) at prices in line with the scarcity of the resource. Long-term contracts are the ideal instrument for sharing these macroeconomic risks. The state can therefore govern and regulate this insurance market, but it must not be completely rigid in demanding adherence to all its terms and conditions.

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