Designing Contracts for the Energy Transition*

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Abstract

This paper explores the design of long-term contracts to support zero-carbon investments in electricity markets. It examines the limitations of spot markets in providing adequate investment incentives, highlighting the role of long-term contracts in mitigating price volatility and facilitating the funding of the investments. A theoretical model is developed to analyze contract design under conditions of moral hazard and adverse selection, emphasizing the trade-offs that arise when exposing firms to price and quantity risk. The findings inform optimal contract design for nuclear and renewable energy projects, offering policy recommendations to enhance investment incentives while minimizing productive inefficiencies and excessive rents.

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1 Introduction

The electricity market is a crucial lever of the energy transition. The shift from polluting thermal power technologies—such as natural gas, coal, and oil—to zero-carbon sources, including primarily renewables but also nuclear power, requires massive investments. One of the greatest challenges for modern economies is how to promote these investments at the necessary speed and scale while minimizing costs for society and consumers.

Over recent years, the expansion of renewable generation has been spurred by a fast decline in the cost of building solar and wind plants. Between 2010 and 2023, the levelized cost of electricity (LCOE) from solar photovoltaic plants decreased by 90%. During the same period, the cost of onshore and offshore wind declined by 70% and 63% respectively (IRENA, 2023). This means that the cost of producing electricity with renewable technologies is now significantly lower than that of the fossil fuel technologies they are intended to replace. As a result, in 2023, more than one third of global electricity production came from renewable sources, nearly half of which was generated by solar and wind power (Ember, 2024).[1] In 2024, solar power generation in the EU surpassed electricity production from coal (Bloomberg, 2025). Figure 1 illustrates the evolution of each power source in Europe until 2023.

The modularity and relatively short construction times of renewable energy plants have the potential to enhance contestability in electricity markets. However, as discussed in Section 2, excessive reliance on electricity spot markets creates a significant barrier for new entrants. Spot market prices are highly volatile and often uncorrelated with the costs of renewable generation, making renewable investors' profits uncertain. While incumbents can hedge these risks through vertical integration between generation and retail, independent producers remain at a disadvantage, as they are fully exposed to spot price fluctuations. Moreover, excessive spot price volatility makes it difficult for new entrants to secure financing for capital-intensive investments, whereas incumbents can leverage profits from their conventional generation assets to improve their financing conditions.

While long-term contracts between independent generators and large buyers have the potential to partially mitigate these asymmetries, they often fall short in practice. A key reason for their limited adoption is exposure to counterparty risk (Fabra and Llobet, 2025). Large buyers have an incentive to renegotiate—or even renege on—the long-term contracts if purchasing at spot prices becomes more attractive, even after accounting for potential breach penalties. This risk is further heightened by the prospect that compliance

[1] Hydroelectric power remains the largest source of renewable electricity.

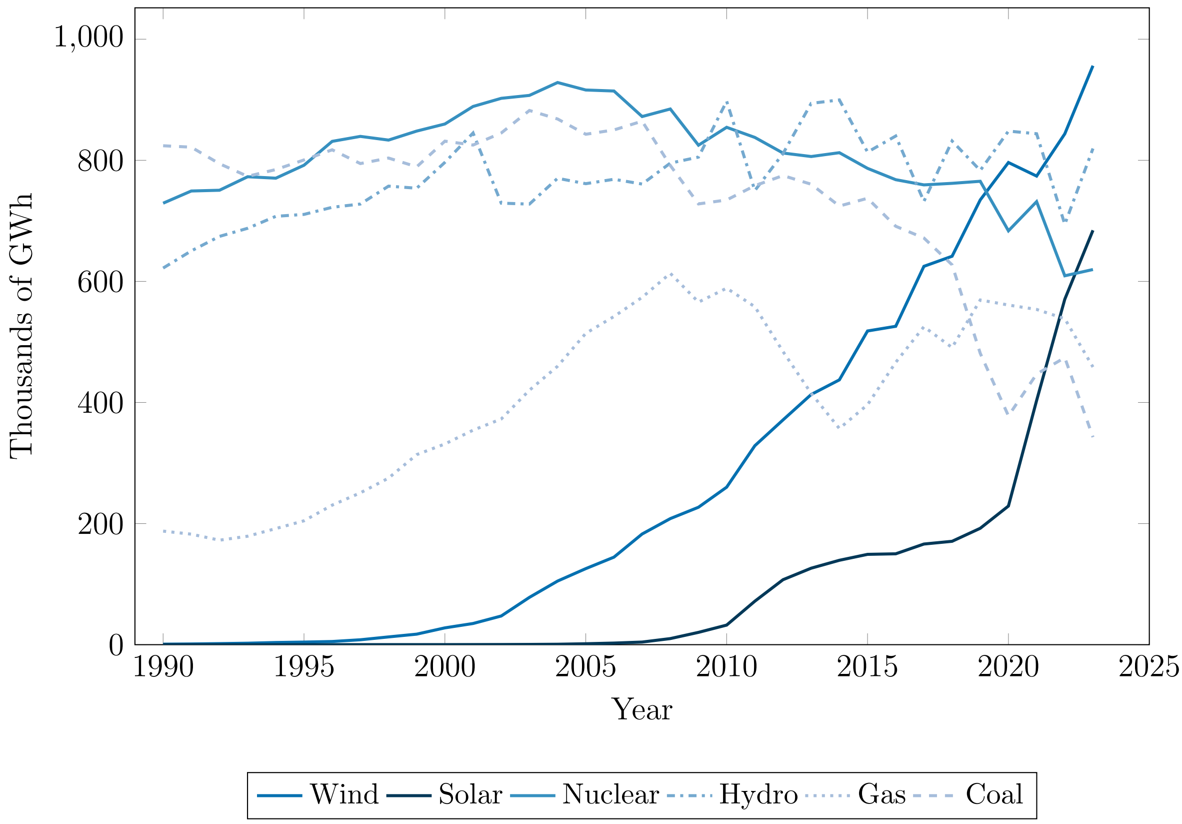

Figure 1: Electricity Production by Technology in the European Union. Source: Eurostat.

with ambitious renewable energy targets will drive down spot prices in the future. As a result, independent generators remain exposed to significant market risks, discouraging investment and ultimately leading to greater market concentration than in the absence of such risks.

Against this backdrop, this paper examines government interventions aimed at mitigating these inefficiencies. As discussed in Section 3, public entities can play a crucial role in enhancing liquidity in long-term contract markets by acting as a counterparty. In turn, this would help minimize counterparty risks, benefiting firms—by reducing their exposure to risk—and consumers—by ultimately leading to lower electricity prices. The key challenge lies in designing these contracts to promote efficient investment and production decisions by the new asset owners.

Accordingly, Section 4 introduces a simple model that provides insights into the optimal design of such contracts. The model shows how well-structured contracts can help derisk investments, enabling projects that would not materialize otherwise. However, due to challenges related to moral hazard and/or adverse selection, it is generally optimal to expose investors to some level of risk—even when they are risk averse. In Section 5, we relate the optimal contract design to remuneration schemes that are often observed in practice, for both renewable and nuclear power plants.

A key takeaway from our analysis is that the efficiency of the Energy Transition can be improved by tailoring contract design for zero-carbon technologies to their specific characteristics. Simply put, nuclear power plants and the various renewable technologies should not be subject to the same remuneration schemes, as the challenges they present are fundamentally different. Derisking the investments through mechanisms that provide a partial hedge against price and quantity risks is essential for both, given the highly capital-intensive nature of these projects. Beyond this, nuclear and renewable technologies possess unique attributes that should be taken into account when designing their contracts.

For nuclear power plants, the primary challenge is to induce the scheduling of maintenance in periods when renewable energy supply is abundant relative to demand, as this is when the social value of lost nuclear output is lowest. Contract design should counteract the natural tendency of nuclear plant owners to schedule maintenance at times when the resulting price increase would benefit other generation assets—often owned by the same company.

In contrast, renewable power plants typically cannot respond to market price signals, as their availability is dictated by weather conditions once the technology and location have been selected. However, investors should be incentivized to choose among different renewable technologies and locations in ways that maximize the social value of investments, taking into account both production costs and value.

The cost and value asymmetries across renewable projects also expose regulators to adverse selection. To optimize the allocation of often limited budgets, regulators should aim to minimize excess rents captured by inframarginal producers while ensuring that the most efficient investment projects are carried out.

The need for attribute-specific contracts that reflect this technological diversity stands in contrast to the prevailing electricity market design paradigm, which tends to favor technology-neutral mechanisms. By offering insights into the optimal contract design for zero-carbon technologies, this paper seeks to inform electricity market design in support of the ongoing Energy Transition.

2 Are Current Electricity Markets Future-Proof?

Until the mid-1980s, the power sector was regarded as a natural monopoly, which explains why a single firm or a few integrated firms controlled all activities—from generation to transmission and distribution. In many cases, these firms were government-owned, with investments driven by political considerations and pricing based on cost-of-service considerations.

The electricity market liberalization that began in the UK marked a shift toward a market-oriented approach. The European Commission embraced this model as a blueprint for transitioning other European markets, amid the opposition of some countries (Bolton, 2021). Transmission and distribution were unbundled from generation, and third-party access to the network was mandated to enable the entry of independent players. Retail choice was introduced to gradually phase out regulated tariffs for final consumers under the expectation that increased competition in the retail segment would, in turn, enhance the contestability of the generation segment. Ultimately, the goal of liberalization was to drive cost efficiencies, enabling countries to benefit from more competitive energy prices.

However, more than thirty years after the liberalization process began, it remains unclear whether the model delivered the expected benefits. The evidence is mixed. In the context of U.S. wholesale electricity markets, Cicala (2022) finds that liberalization reduced generation costs by 5 percent, primarily through allocative efficiency gains from trade across states. Other studies have reported reductions in labor and fuel costs but found no significant improvements in power plants' efficiency in converting heat into electricity (Fabrizio et al., 2007). The downside is that liberalized electricity markets have also proven vulnerable to market power exploitation, both in wholesale and retail markets. Among many others, Green and Newbery (1992) and Borenstein et al. (2002) provide evidence of market power in electricity wholesale markets, and Dressler and Weiergraeber (2023) in retail markets.

Market power remains a major concern due to the prevailing structure of most electricity markets, which are still characterized by high horizontal concentration and vertical integration between generation and retail. This has given incumbents a competitive advantage over independent entrants, reducing market contestability and often preventing excessive rents from being competed away — as was evident during the recent energy crisis in Europe (Fabra, 2023). Moreover, competition in the retail segment has fallen short of expectations. The limited scope for product differentiation together with the high switching costs have made it difficult for new entrants to gain market share (Joskow, 2000).

The lack of market contestability was partly driven by the European Commission's initial reluctance to actively promote long-term contracts. The concern, explicitly stated in the 2007 Energy Sector Competition Inquiry (European Comission, 2014*b*), was that incumbents might use such contracts with large buyers to foreclose the generation market (Roques and Duquesne, 2024). However, this perspective overlooked the fact that incumbents were vertically integrated, while independent entrants lacked the ability to replicate this arrangement due to the absence of liquid long-term contract markets.

2.1 The Limits of Spot Markets

As a consequence of the evolving electricity market design and structure, independent companies—whether in generation or retail—have had limited opportunities to hedge against the inherent volatility of spot electricity markets. Market risk has become an increasingly pressing issue as the need for additional capacity—primarily from renewable energy sources—continues to grow with the progress of the energy transition. Likewise, the energy crisis that hit Europe in 2021–2022, along with concerns over security of supply, has further intensified the debate on extending the lifespan of existing nuclear power plants and financing new reactors with state aid support (European Comission, 2024, 2025).

Basic economic theory suggests that well-functioning spot markets provide the appropriate signals for both production and investment. However, electricity markets rarely meet the ideal conditions for efficiency. As a result, alternative market designs influence long-term investment decisions and short-term production choices differently.

The consequences for investment are particularly pronounced for renewable energy and nuclear power. These technologies require substantial upfront capital-intensive investments, yet their low marginal production costs make it optimal for them to be dispatched at all times.[2]

As a result, financing costs are a key determinant of the overall cost of renewable energy projects. However, electricity prices in spot markets are highly volatile, as they tend to reflect the costs of gas-fired generation. Since these prices are largely uncorrelated with their own generation costs, full exposure to market prices leads to highly volatile profit margins for renewable and nuclear generators.

Lenders internalize the uncertainty over cost recovery, making it difficult for low-carbon generators exposed to spot prices to secure financing at competitive rates. This challenge is even more severe for nuclear power plants, which beyond requiring massive capital investments, have a long history of cost overruns.[3]

For thermal power plants, exposure to spot market prices is essential to foster efficient production. When these markets function properly, thermal plants are dispatched only when the value of their output—reflected in market prices—exceeds their marginal costs. While this introduces some quantity uncertainty, it also provides a degree of protection

[2]For renewable energy, this is due to its negligible marginal cost of production. For nuclear power plants, this occurs because of the high costs associated with shutting down and ramping up production.

[3]One of the most striking examples is Hinkley Point C, a nuclear plant in the UK with a capacity of 3,200 MW. In 2015, it was expected to be operational by 2025 at a cost of £31–35 billion. By 2024, the estimated cost had risen to £41–47 billion, with the completion date pushed back to 2031.

against price volatility. Indeed, to the extent that thermal plants are price-setting, market prices provide a natural hedge against changes in their production costs. In contrast, renewable power plants operate at their available capacity whenever market prices are non-negative. As a result, linking their remuneration to short-term prices is less critical for ensuring efficient production allocation but exposes them to additional price risks.

Short-term markets provide adequate investment incentives if they accurately reflect the social value of new capacity. This is the core principle behind the energy-only market paradigm, as advocated by the Electric Reliability Council of Texas (ERCOT). However, recent events suggest that under real-world conditions, these markets may fail to deliver sufficient investment incentives (Mays et al., 2022).

The efficiency of energy-only markets hinges upon several assumptions that are difficult to fulfill in practice. Some are standard, such as the absence of market power and the internalization of environmental externalities through carbon pricing. However, two additional assumptions are particularly relevant to our analysis. First, there should be no frictions in the real-time responsiveness of demand to price fluctuations. Second, forward markets must enable power producers and retailers to effectively hedge against all future price contingencies.

Regarding the first assumption, the widespread use of time-invariant electricity prices means that consumers have little incentive to respond to real-time price fluctuations. Even when real-time pricing is implemented, consumer responsiveness remains weak due to a lack of awareness, poor price information, and high transaction costs (Fabra et al., 2021). As a result, during periods of scarcity, high energy prices alone may not be enough to sufficiently curtail consumption and prevent blackouts. This was evident in Texas during the February 2021 energy crisis, when electricity prices surged past 9,000 USD/MWh—compared to an average of 50 USD/MWh—yet still failed to prevent widespread blackouts, while leaving consumers with exorbitant energy bills and limited ability to respond.

To address these concerns, electricity markets often deviate from the energy-only paradigm by implementing price caps in spot markets and introducing capacity payments. Price caps are used to protect consumers who cannot respond to real-time price fluctuations and mitigate market power (Joskow and Tirole, 2006; Fabra, 2018), but they create a gap between the social value of electricity and its market price, leading to the so-called *missing-money problem*. Backup plants are often maintained solely to capture the high prices that emerge during peak demand periods. However, if price caps suppress these scarcity signals, underinvestment is likely to occur unless capacity payments compensate for the missing-money problem.

In recent years, this issue has gained prominence due to growing concerns over the security of supply. As the share of electricity generated from renewable sources increases, so does the intermittency of available production. This, in turn, raises the social value of maintaining plants capable of supplying power under exceptional circumstances, even if they are rarely dispatched. Capacity markets have emerged as a mechanism to compensate these plants for their availability (Fabra, 2018; Llobet and Padilla, 2018), ensuring remuneration that is independent of their actual output.

The second assumption—the existence of complete forward markets—is also problematic in electricity markets, particularly over long horizons, giving rise to the so-called *missing-markets problem* (Newbery, 2016). The mismatch between the long lifespan of production assets and the limited ability to hedge future risks forces investors to bear a significant share of these uncertainties. This challenge is especially relevant in the context of the energy transition, where the future trajectory of market prices remains highly uncertain. In recent years, geopolitical shocks have further contributed to significant price fluctuations.

These challenges have reignited the debate on the role of long-term contracts. In line with the classical Theory of the Firm, long-term contracts have been presented as an alternative to organized financial markets, offering an efficient mechanism for allocating market risks among firms that are not vertically integrated. Spot markets imply negatively correlated risk for electricity buyers and sellers. Consequently, they can mutually benefit from long-term contracts that establish stable prices over the asset's lifetime. Large buyers may find these arrangements advantageous even if they are not risk-averse, as sellers are often willing to accept lower prices in exchange for greater price stability.

The next section explores these contracts in greater detail.

2.2 Markets for Long-Term Contracts

There is broad consensus regarding the need to promote long-term contracts. For example, the European Commission has made this a central objective of its electricity market design reform, emphasizing that its *"ultimate objective is to provide secure, stable investment conditions for renewable and low-carbon energy developers by bringing down risk and capital costs while avoiding windfall profits in periods of high prices"* (European Commission, 2023). Similarly, the World Bank has emphasized that long-term power contracts are *"central to the private sector participant's ability to raise finance for the project, recover its capital costs, and earn a return on equity"* (World Bank, 2024).

Indeed, as acknowledged by both institutions, financiers tend to favor investors in renewable energy that can secure a long-term contract for the sale of their output at stable prices. Gohdes et al. (2022) examine a sample of VRE projects and show that a greater proportion of the output covered by a long-term contract is associated with lower entry costs through higher leverage and lower credit spreads. This effect is stronger the higher the credit rating of the counterparty.

The use of long-term contracts to support renewable energy investment has grown significantly in recent years. As shown in Figure 2, the contracted capacity in Europe quadrupled between 2018 and 2023. While some of these contracts involve utilities as counterparties, energy-intensive firms remain the primary buyers. The evidence also reveals that Information and Communication Technology (ICT) companies represent the largest share of these buyers. Data centers, with their high energy demands, benefit from securing green energy at fixed prices to stabilize their costs and comply with their ESG commitments.

However, there is a widespread perception that these contracts are not fully realizing their potential in driving new investment in renewable energy at the required speed and scale (Polo et al., 2023). This is further reflected in the geographic concentration of Power Purchase Agreements (PPAs) within a limited number of European countries.

Despite the consensus on the need to promote long-term contracting, there is a lack of diagnosis as to why PPA markets have failed to provide enough liquidity for long-term power contracts. The European Commission acknowledges that *"a barrier to the growth of this market is the credit risk that a consumer will not always be able to buy electricity over the whole period."* However, beyond expressing this concern, the implications of counterparty risk on the performance of PPA markets have not been explored in detail.

Fabra and Llobet (2025) investigates the implications of counterparty risk in long-term contract markets, focusing on situations where buyers may default or renegotiate contracts if prices in short-term markets become relatively more favourable.[4] To do so, the paper develops a theoretical model in which buyers and sellers trade a homogeneous good in a short-run (or spot) market characterized by price volatility. Because sellers are risk-averse, they have an incentive to enter into fixed-price contracts to hedge against price uncertainty.

However, contracts might not fully hedge sellers from future price volatility if, along the contract's duration, there is a positive probability that the buyer defaults on the contract — either opportunistically, or out of necessity (e.g., for instance, a retailer losing market share due to uncompetitive prices or an energy-intensive consumer going bankrupt). The model distinguishes between *trustworthy* buyers, who always honor contracts, and *opportunistic* buyers, who default when it is advantageous to do so, e.g., when spot prices drop sufficiently below the contract price relative to the contract's collateral.[5]

[4]While electricity markets are the paper's main motivation, the analysis applies more broadly to other markets for which long-term contracts are essential for securing capital-intensive investment and mitigating price volatility.

[5]An extension of the model incorporates dynamic interactions, recognizing that contracts span mul-

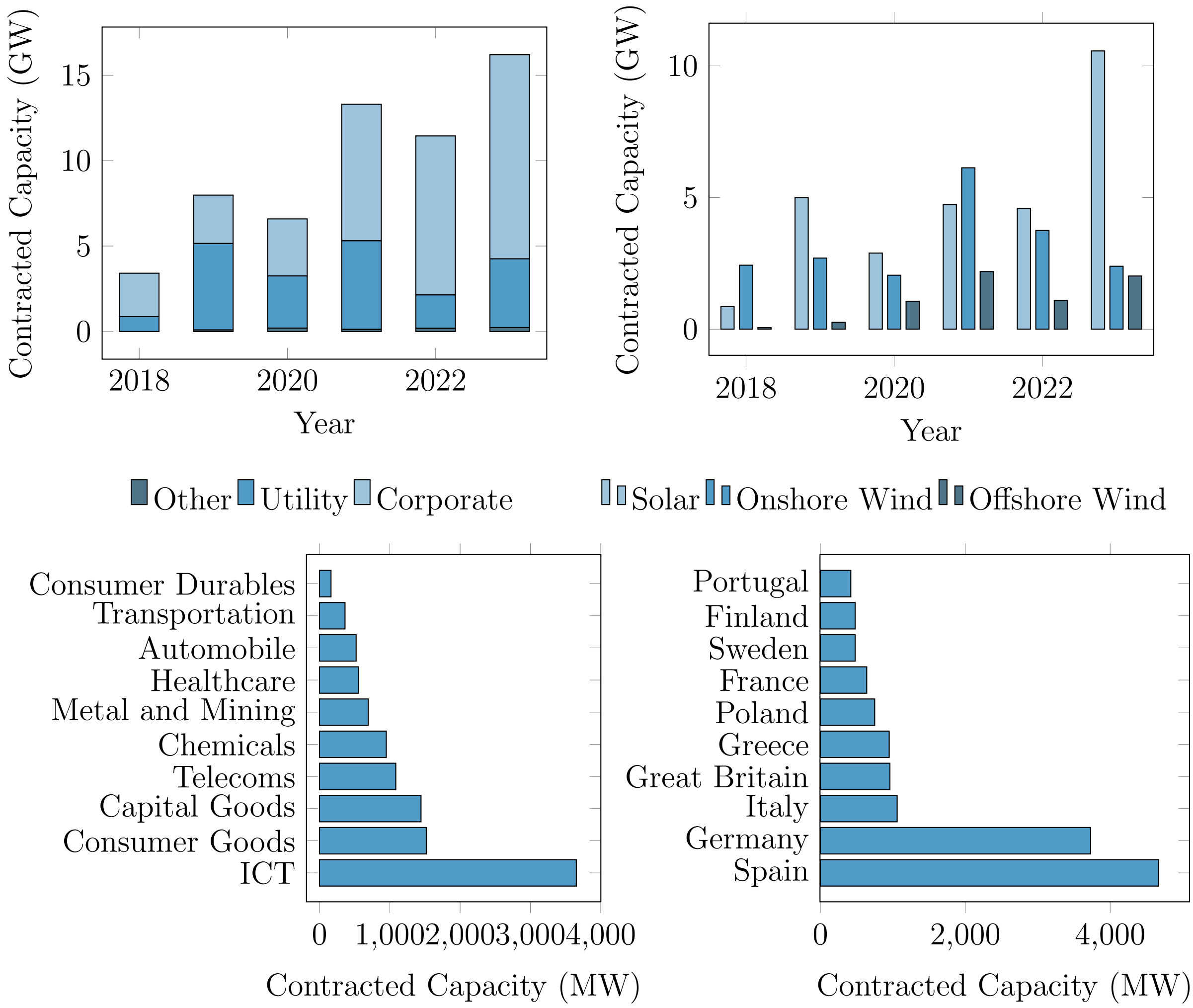

Figure 2: The market for PPAs in Europe. Contracted capacity by type of buyer (upper left) and industry to which corporate buyers belong (lower left). Capacity by technology (upper right) and new capacity contracted by country in 2023 (lower right). Source: Plexapark.

The proportion of opportunistic buyers in the market determines the extent of contract risk and influences the equilibrium outcomes.

In particular, relative to the spot market, long-term contracts allow sellers to reduce their risk premia, and hence they are willing to sign contracts at fixed prices below the expected spot market price. However, if buyers behave opportunistically, sellers require higher contract prices to compensate for the increased price volatility they would face in case of default.

These insights have two key implications. Firstly, long-term contracts enable potential sellers to make capacity investments that would not occur otherwise. By reducing

tiple periods and that future price expectations influence current decisions. When prices fluctuate over time, an opportunistic buyer may still choose to honor a contract if defaulting today means losing the ability to hedge against future price increases. This dynamic effect can partially mitigate counterparty risk by introducing an implicit cost to defaulting.

sellers' risk premia, they lower investment costs, allowing more investors to break even. These additional investments are efficient, as their production displaces that of higher-cost generators, leading to productive cost savings that exceed investment costs. This result supports the rationale for promoting long-term contracts in practice.

Secondly, the equilibrium outcome under long-term contracts falls short of achieving the First-Best. Specifically, as sellers raise contract prices to account for default risk, the profitability of these contracts is reduced, leading to a reduction in investment which, in turn, further increases the price. The price effect amplifies risk premia across all contracts, as opportunistic buyers are more likely to default when contract prices rise. Meanwhile, the resulting underinvesment prevents some cost savings from materializing. Ultimately, if the extent of counterparty risk is too high (either because there are too many opportunistic buyers, or because the likelihood of low spot prices becomes too high), sellers may either set prohibitively high prices or withdraw from the market altogether, causing the long-term contract market to unravel.

3 The Role of Public Policy

The lack of market liquidity in private long-term contract markets opens the door to policy interventions. One potential solution for mitigating the adverse effects of counterparty risk is the provision of public guarantees, which shift default risk from sellers to the government. As shown by Fabra and Llobet (2025), this intervention lowers contract prices and increases investment, but at the cost of creating moral hazard. The reason is that, anticipating government protection, sellers increase contract prices, which in turn makes default more likely.

Another policy tool for reducing counterparty risk involves collateral requirements, where buyers must post financial security to ensure contract compliance. While this reduces counterparty risk, it imposes financial burdens on buyers, potentially restricting market participation.

Investment subsidies, conditional on the investor signing a long-term contract, are also effective in promoting contract market liquidity. However, subsidies require careful design, as they involve public expenditures and may lead to excessive inframarginal rents, where firms receive financial support even if they would have invested in their absence.

In sum, the need to promote liquidity in long-term contracts should not obviate other potential problems that can arise. As previously discussed, each of these policy interventions presents trade-offs: public guarantees reduce the costs of counterparty risk for investors but may encourage excessive risk-taking; public support encourages investments but it is costly; collateral requirements enhance contract reliability but limit market participation.

Moreover, even if liquidity issues are addressed, other challenges remain. A key issue is the lack of transparency in long-term contract markets, particularly when contracts between private parties are involved. Price opacity hinders competition, creates barriers for new entrants, and weakens long-term investment signals. Some companies gather and sell data about PPAs, but not only is this data expensive, it is also rarely based on actual transaction data.

Additionally, when energy retailers enter into PPAs at prices below the expected spot prices, there is no guarantee that they will pass on the cost savings to consumers. This is because retailers set electricity prices based on the prevailing market equilibrium, rather than the price they pay for electricity upstream. Finally, without appropriate safeguards, energy tied to PPAs may not be sufficiently available in the wholesale market, reducing market liquidity, and potentially undermining competition and efficiency.

These issues are mitigated when a public entity (broadly understood) serves as the counterparty to long-term contracts, commonly referred to as Contracts-for-Differences (CfDs). Under this contractual arrangement, the producer sells its output in the market, while the regulator settles the difference between the contract's strike price and the prevailing market price.[6]

CfDs not only expand contract demand by enabling buyers who find it too costly to engage in long-term contracts to participate, but they also help mitigate counterparty risk. This is because the regulator has the authority to enforce the contract price, ensuring that payments remain stable even if spot prices drop below the strike price.

As a result, buyers benefit from the lower prices that sellers are willing to offer for these contracts in exchange for mitigating their risks. For example, in Europe, the revenues collected from CfDs can be used to support vulnerable customers and those affected by energy poverty, as well as to finance investments in energy efficiency, distribution grid development, or electric-vehicle charging infrastructure, among others (European Commission, 2023). However, as acknowledged by the European Commission, it is crucial that the redistribution of CfD revenues ensures that customers remain somewhat exposed to the price signal, in order to avoid distorting efficient consumption decisions.

One of the concerns regarding CfDs is that they might crowd out PPAs, as noted by European Commission (2023) when it calls Member States to *"ensure that support schemes do not constitute a barrier for the development of commercial contracts such as PPAs."* Fabra and Llobet (2025) demonstrates that CfDs indeed have the potential to crowd out the PPA market, either partially or fully. However, the outcome with

[6] A two-way CfD requires the firm to pay the regulator if the strike price falls below the market price. In contrast, a one-way CfD only involves payments from the regulator to the firm when the market price is below the strike price.

CfDs is welfare superior even if PPAs a crowded out, as CfDs enhance contract liquidity while reducing counterparty risks, particularly when the performance of the private PPA market is weak in both dimensions.

Relative to PPAs, CfDs offer an important additional advantage. When private parties enter into a bilateral contract, they do so to serve their own needs, often disregarding the externalities they create. In this regard, contract design becomes critical. While most PPAs remunerate renewable generators with a fixed price for their actual output, this can lead to inefficiencies in production and investment decisions, which can be mitigated by the regulator through an adequate contract design.

Taking these considerations into account, regulators could design CfDs in a way that better contributes to overall market efficiency. We now develop a simple model to illustrate how such contracts should be designed, depending on the technology's attributes. Our setup can encompass both moral hazard and adverse selection, allowing the social value of an investment to increase through costly effort and the optimal selection of the project characteristics. The model incorporates risk-averse investors and allows for different social weights of consumers and producers.

4 Designing Power Contracts: a Simple Model

Consider a power plant with a marginal cost normalized to zero for production up to its unit capacity. Production fluctuates between being fully available (so the plant can produce $q = 1$), or completely unavailable ($q = 0$). Market prices can be either $p = 0$ and $p = 1$, reflecting the marginal cost of the last unit of production and, consequently, the cost savings originated when it is replaced during those periods.[7] Both price levels occur with equal probability. The correlation between the plant's availability and market prices is governed by the conditional probabilities

$$\Pr(q = 1|\, p = 1) = \beta + e,$$
$$\Pr(q = 1|\, p = 0) = \beta - e,$$

where $e \leq 1 - \beta$ denotes the plant's effort to shift production from low-priced to high-priced periods.[8] Notice that $E(q) = \beta$ and, therefore, effort has no impact on expected output.

[7] This assumption can be interpreted, for example, as capturing situations where renewable energy is enough to cover the whole market, and prices are 0 or a situation where fossil fuels are necessary and the price of 1 normalizes the marginal cost of these plants.

[8] To simplify the exposition, we do not explicitly consider situations where $\beta < e$, which would imply a negative probability when $p = 0$. As market revenues are 0 in this case, considering a 0 bound would have no effect on the results.

Plants may differ in their expected production. When unobservable to the regulator, this may lead to *adverse selection*. We assume that there is a unit mass of plants with β values that are uniformly distributed in the unit interval. Similarly, because plant owners can exert effort to align their production with market prices, the model has a *moral hazard* dimension when effort, e, is unobservable. Production and effort are costly. We use $C(\beta, e)$ to denote the associated cost function, which is increasing in both arguments.

We consider contracts that potentially compensate both capacity and output. Specifically, given an output realization q and a prevailing price p, the regulator specifies a remuneration

$$F + fq + \alpha pq,$$

where F is a capacity payment, $f \geq 0$ is a fixed price per unit of output and $\alpha \in [0, 1]$ is the degree of price exposure to spot prices. We summarize contracts as a vector (F, f, α).

In the spirit of Fabra and Llobet (2025), we assume that investors are risk-averse, and use $R(\beta, e; f, \alpha)$ to capture their risk premium. We interpret this premium as arising from mean-variance preferences so that investors make decisions to maximize their expected profits minus the variance of their cash flows with weight $r \geq 0$.

Given a contract, an investor with a project of expected production β who exerts effort e obtains expected utility

$$U(\beta, e) = F + f\beta + \alpha\frac{\beta + e}{2} - R(\beta, e; f, \alpha) - C(\beta, e), \tag{1}$$

where the expected production is $E(q) = \beta$ and the expected revenue is $\frac{\beta+e}{2}$. Throughout the analysis, it will become handy to refer to the firm's expected utility gross of the fixed payment, $u(\beta, e) \equiv U(\beta, e) - F$.

With mean-variance preferences, the implied risk premium is equal to

$$R(\beta, e; \alpha, f) = r\left[f^2\beta(1-\beta) + f\alpha(\beta + e)(1-\beta) + \alpha^2\left(\frac{\beta + e}{2}\right)\left(1 - \frac{\beta + e}{2}\right)\right]. \tag{2}$$

This risk premium, proportional to the variance of cash flows, can take three values. The producer gets a remuneration equal to $F + f + \alpha$ if $p = 1$ and $q = 1$, an event which occurs with probability $(\beta + e)/2$; equal to $F + f$ if $p = 0$ and $q = 1$, an event which occurs with probability $(\beta - e)/2$, and F otherwise. We can establish the following properties:

Lemma 1. *The risk premium $R(\beta, e; f, \alpha)$ is increasing in r, e, α, and f. Furthermore, $\frac{\partial^2 R}{\partial^2 e} < 0$, $\frac{\partial^2 R}{\partial^2 \beta} < 0$, and $\frac{\partial R}{\partial e \partial \beta} < 0$.*

When $r, \alpha > 0$, the risk premium $R(\beta, e; f, \alpha)$ is increasing in e. This means that, while promoting effort increases production at times when it is most valuable, it also increases the risk premium. In turn, increasing e raises the risk premium less when β is higher, which induces higher effort for the projects that are more productive.

Total welfare is defined as the weighted sum of consumer and producer surplus. When the project is carried out by an investor with a plant of expected production β who exerts effort e, total welfare is

$$W(\beta, e) = (1-\alpha)\,\frac{\beta+e}{2} - f\beta - F + \gamma U(\beta, e),$$

where $\gamma \in [0,1]$ is the weight of the firm in the social welfare function. The first three terms correspond to the surplus that consumers obtain from the operation of the new project, the expected cost of the fixed price per unit of production, and the fixed payment, respectively. The regulator's objective is to efficiently procure the construction and operation of exogenous capacity $\theta \leq 1$ within the space of contracts (F, f, α), subject to the firm obtaining non-negative profits.

To simplify the exposition, we analyze the model under two different assumptions. First, we consider a setting where only moral hazard is present. Second, we consider situations where only adverse selection is at play. We will use specific parametric cost functions for $C(\beta, e)$ to obtain closed-form solutions.

4.1 Moral Hazard

Consider the case in which expected output β is contractible, but effort e is not. We parametrize the cost function as $C(e) = c\frac{e^2}{2}$, and assume $r < 2c$.[9] Because β is contractible, our results readily extend to cost functions that depend on β.

As social welfare is increasing in β, the regulator will offer a contract only to investors with $\beta \geq 1-\theta$. The contract can be tailored to each β, meaning that rents are minimized by offering each investor a contract that makes the participation constraint binding. Hence, in this case, maximizing welfare is equivalent to maximizing total surplus,

$$W(\beta, e) = (1-\alpha)\,\frac{\beta+e}{2} - f\beta + u(\beta, e). \tag{3}$$

From equations (1) and (2), we can conclude that the usage of a per-unit output compensation f is dominated by a capacity payment, F. A higher f increases the variance of the cash flows, implying that a higher f discourages effort without increasing the social value of production. Furthermore, as opposed to F, payments based on output are not a pure transfer from consumers to producers as they give rise to additional risk, which needs to be compensated. Consequently, it is optimal to set $f^* = 0$ and use F to ensure that the firm breaks even at its optimal effort level.

Lemma 2. *Under Moral Hazard and when β is contractible, the optimal contract does not condition on actual output, $f^* = 0$.*

[9] As it will be clear below, this condition guarantees that the investor's expected utility is concave in effort, implying that the direct effect of exerting effort dominates over the increase in the risk-premium.

Interestingly, we can interpret this result as an indication that, under moral hazard, investors should be compensated based on their expected production β rather than realized production q, i.e., $F = fE(q)$. The key assumption driving this result is that effort affects only the correlation between production and market prices, not production itself.[10] This assumption is reasonable, for example, for the case of nuclear power plants, which require regular maintenance that can be scheduled at different times during the year with varying implications for cost and firm revenue but not for total output.

Once we restrict our analysis to efficient contracts so that $f^* = 0$, we can simplify the risk premium as

$$R(\beta, e; 0, \alpha) = r\alpha^2 \left(\frac{\beta + e}{2}\right)\left(1 - \frac{\beta + e}{2}\right).$$

The next result characterizes, for a given contract, the level of investment that maximizes the profits of an investor with a project of average production β.

Lemma 3. *There exists $\underline{\beta} < \overline{\beta}$ such that optimal effort e^* exerted by a $\beta-$type investor under a contract $(F, 0, \alpha)$ can be characterized as follows:*

(i) For $\beta < \underline{\beta}$, $e^* = 0$.

(ii) For $\beta \in \left[\underline{\beta}, \overline{\beta}\right]$, the solution is interior with

$$e^* = \frac{\alpha\left(1 - r\alpha\left(1 - \beta\right)\right)}{2c - r\alpha^2} \in (0, 1 - \beta).$$

(iii) Otherwise, $e^* = 1 - \beta$.

For a low-production plant, it is optimal not to exert effort, as it is more adversely affected by the increased profit volatility that comes with positive effort. In contrast, a higher-production plant finds it optimal to exert positive effort, which is increasing as expected production rises. Eventually, a corner solution is reached when the optimal effort level becomes high enough that the plant consistently operates at full capacity during high-price periods. Beyond this point, a high-production plant no longer needs to exert as much effort to maximize output when market prices are favorable.

In anticipation of the plant's effort choice, the regulator can now determine the optimal degree of price exposure. Take intermediate values of β, for which the interior effort level applies. The derivative of the welfare function in (3) determines the optimal level of price exposure as the result of the following first order condition:

$$\frac{1}{2}\left(1 - \alpha\right)\frac{\partial e^*}{\partial \alpha} = 2\alpha R(\beta, e; \alpha, 0). \tag{4}$$

[10] If expected production were affected by e, a higher f could foster greater effort, potentially altering the previous trade-off.

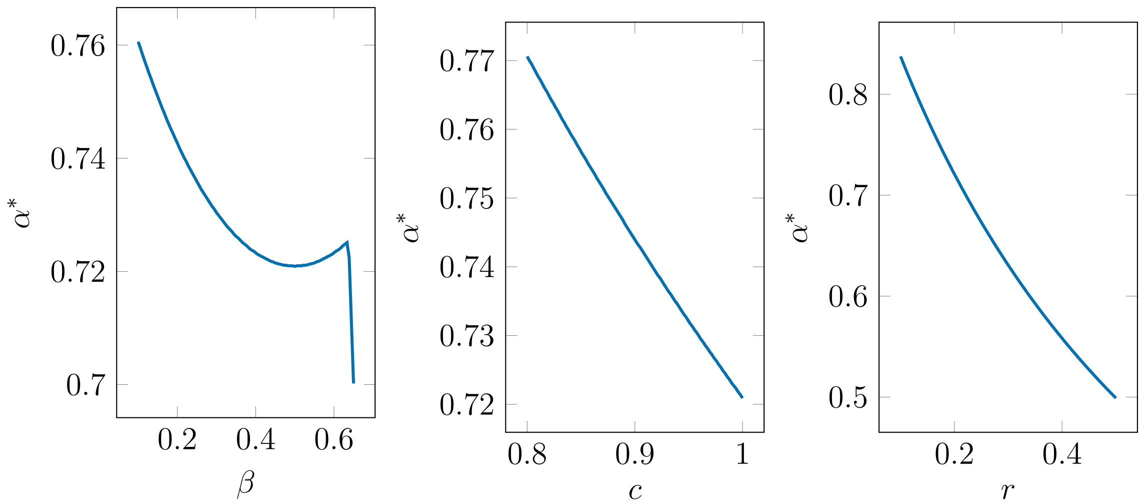

Figure 3: Optimal value of α as a function of β, c, and r. Baseline parameters: $r = 0.2$, $\beta = 0.5$, and $c = 1$.

This equation reflects a risk-efficiency trade-off. On the one hand, a higher α enables the firm to capture a greater share of the social value generated by its effort, inducing higher effort. On the other hand, a higher α also increases the volatility of cash flows and, hence, the firm's risk premium which needs to be compensated by consumers through a higher fixed payment F. The optimal degree of price exposure balances out these two countervailing effects and leads to an interior solution for α.

Proposition 1. *For $r > 0$, and any β, the social optimum is characterized by partial price exposure, $\alpha^* \in (0, 1)$.*

Crucially, the risk-efficiency trade-off ensures that neither extreme contract — a fixed payment nor full price exposure — is ever optimal. Reliance on a fixed payment ($\alpha = 0$) is inefficient because it eliminates the firm's incentive to exert effort, as it receives the same price regardless of its effort level. However, some effort is socially beneficial, in spite of the risk it entails, as it shifts production from periods of zero value to times when it has a positive value, while the marginal cost of effort remains zero when none is exerted. Conversely, full price exposure ($\alpha = 1$) is also suboptimal, as it leads to inefficiently high risk. In this case, the marginal value of additional effort is zero, yet the increased exposure to price volatility raises the firm's risk premium.

Figure 3 illustrates how the optimal level of price exposure changes with the main parameters of the model. As it is intuitive, a higher risk premium, reflected in a higher r, increases the cost of inducing effort and makes it optimal to reduce price exposure. Similarly, a lower productivity of effort reduces the benefits from exposing the firm to risk. The effect of β on α^* is not monotonic and the interpretation stems from Lemma 3. When β takes an intermediate value, price exposure increases with β as this implies an increasing productivity of effort induced by a high α. When β is small, however, effort is not very sensitive to α due to the resulting risk premium. A lower price exposure induces consumer gains through the term $(1-\alpha)$ in (4), which overpower the lower effort that it entails. Finally, if β is high, the constraint $\beta + e \leq 1$ becomes binding. A high exposure does not foster additional effort, and it becomes optimal to choose the lowest α for which $e^* = 1 - \beta$.

4.2 Adverse Selection

Consider now a scenario where expected output, β, is observable ex-post, but it is not contractible, meaning that all plant types must be offered the same contract. Assume that the cost of effort is prohibitively high, leading to no effort being exerted ($e^* = 0$), and implying that plants produce expected output β regardless of the market price. Hence, we omit e from the rest of the analysis to focus on the adverse selection dimension. To simplify our calculations we assume a cost function $C(\beta) = \frac{\beta^2}{4}$, which guarantees that in a perfect information setup it is in the interest of the regulator to select the most efficient plants.

The expected utility of a project with expected production β is

$$U(\beta) = F + f\beta + \alpha\frac{\beta}{2} - R(\beta; \alpha, f) - C(\beta),$$

and, as before, we define $u(\beta) \equiv U(\beta) - F$. The risk premium expression in (2) simplifies to

$$R(\beta; f, \alpha) = r\left[f\beta(1-\beta)(f+\alpha) + \alpha^2\frac{\beta(2-\beta)}{4}\right].$$

The social welfare associated with the participation of a project β is now

$$W(\beta) = (1-\alpha)\frac{\beta}{2} - f\beta - F + \gamma U(\beta),$$

which, in contrast to the moral-hazard case, does not necessarily imply $U(\beta) = 0$, as the regulator can no longer offer a contract that depends on the characteristics of each project.

Our first result shows that under adverse selection, the usage of per-unit payments, f, is always superior to offering price exposure α.

Lemma 4. *Consider all contracts of the form (F, f, α) that yield a utility, gross of the fixed payment, of $u(\beta) = \bar{u}$. For any type $\beta > 0$, social surplus is higher when $\alpha = 0$.*

This result, which implies $\alpha^* = 0$, is in stark contrast with the previous case. Under moral hazard, the per-unit output payment was detrimental to effort, as it yielded an increase in the risk premium, but not on effort, that had to be compensated. Without moral hazard, a per-unit payment is superior to price exposure because, for the same increase in the expected remuneration, it yields a lower risk premium.

This result applies to all projects regardless of the value of β, allowing us to focus, without loss of generality, on contracts of the form $(F, f, 0)$. Since $\alpha^* = 0$, the expected utility of a project of type β simplifies to

$$U(\beta) = F + f\beta - rf^2\beta(1-\beta) - C(\beta). \tag{5}$$

The social welfare it generates can, therefore, be written as

$$W(\beta) = \frac{\beta}{2} - f\beta - F + \gamma U(\beta),$$

where $U(\beta) \geq 0$. If β were observable, the optimal contract would call for $f = 0$ as this would both eliminate rents (which have a lower weight in the social welfare function than the corresponding cost for consumers) and also eliminate the risk incurred by all plants, allowing for a decrease in F. In this case, with β observable and $f = 0$,

$$W(\beta) = \frac{\beta}{2} - C(\beta).$$

The parametrization $C(\beta) = \frac{\beta^2}{4}$ guarantees that, absent any friction, social welfare is increasing in β, making it optimal for the regulator to select a mass θ of plants with the highest β.

In contrast, when β is not observable, the regulator must offer the same contract to all projects, making it impossible to achieve the socially optimal allocation. Since the choice of $f = 0$ implies $U'(\beta) = C'(\beta) < 0$, such a contract would only entice the participation of the projects with the lowest expected production.

To better understand the implications of asymmetric information, in the remainder of this section we focus on the two-type case. We assume that β can be either $\underline{\beta} < 1$ or $\overline{\beta} = 1$, with the same probability 1/2. We also assume $\theta > \frac{1}{2}$, so that plants of both types are required to fulfill the demand requirement, making the asymmetric information problem relevant.

Using (5), we can write the expected utility of both types as

$$\begin{aligned} U(1) &= f - C(1) + F, \\ U(\underline{\beta}) &= F + f\underline{\beta} - rf^2\underline{\beta}(1-\underline{\beta}) - C\left(\underline{\beta}\right). \end{aligned}$$

Consider a contract that induces an efficient allocation, i.e., demand is covered by all plants with high production, and the residual demand $\theta - \frac{1}{2}$ is covered by the low production plants.[11] Unlike the case with perfect information, $f > 0$ is now required to

[11] We assume that, when indifferent, the tie-breaking rule selects the plants with the highest revenue. We also assume if a plant participates, those that would obtain higher profits would also participate.

induce the separation between the two types. In particular, this allocation requires

$$f \geq \underline{f} \equiv \frac{\sqrt{r\beta(1-\beta)+1}-1}{2r\beta} > 0,$$

arising from $U(1) = U(\underline{\beta})$.

Proposition 2. *Consider the Adverse Selection case with two equally-likely types, $\beta \in \{\underline{\beta}, 1\}$. Under the optimal contract $(F^*, f^*, 0)$, the plant selection is efficient and all firms obtain zero rents. This contract is characterized by $f^* = \underline{f}$ and $F^* = \underline{f} - C(1)$.*

Since $\gamma \leq 1$, the optimal choice of F ensures that low-production plants earn zero profits. Consequently, setting $f > \underline{f}$ is dominated by setting $f = \underline{f}$ for two reasons. First, a higher f raises the risk premium borne by low-output plants, which must then be offset by consumers through an increase in F. Second, raising f creates rents for high-production plants, which, when $\gamma < 1$, results in a welfare loss. Because, in this case, plant selection is efficient and no rents are allocated, the outcome is already optimal and cannot be further improved.[12] Hence, the optimal contract requires $f^* = \underline{f}$ and $F^* = f^* - C(1)$.

Notice that $\underline{f}$ is decreasing in r. The reason is that, as the risk premium becomes more relevant, separating the two types of plants is easier and, therefore, a lower distortion is necessary. In turn, this lower payment can be compensated with a higher F, which implies no distortion. As a result, in cases where r is sufficiently high, f^* is low and firms are mostly financed through a positive fixed payment.

This result has important implications for contract design. Forcing the regulator to choose $F = 0$ in instances where r is high would require a higher per-unit payment f at the cost of increasing the risk premium. Similarly, if r is low and the optimal contract requires $F < 0$, a restriction to compensate firms solely through output would result in high rents.

5 Contract Design in Practice

Our analysis recommends against a one-size-fits-all approach in the electricity market. The optimal contract varies depending on the specific attributes of each technology. Here, we elaborate on how to design contracts in practice for nuclear and renewable power plants through the lenses of our simple model.[13]

[12] Notice that the alternative contract would imply $F = \frac{1}{4}$ and $f = 0$. In that case, risk is completely eliminated and $U(1) = 0 < U(\underline{\beta})$. This allocation is inefficient as it would imply that a proportion $1 - \theta$ of plants with production $\overline{\beta} = 1$ are not built.

[13] See Kröger and Newberry (2024) for a more detailed discussion on how these contracts are implemented in practice. Leblanc (2024) provides a numerical assessment of some of these contracts.

Nuclear power plants Their expected output is observable, as they generally operate at full capacity (absent outages), except during maintenance periods. Therefore, the regulator can design the contract based on the plant's expected output. The key challenge is incentivizing nuclear operators to schedule maintenance during low-priced periods, when the social value of production lost during those times is also low. One concern is that those periods may not necessarily coincide with the time when their cost of carrying out maintenance works is the lowest. More important, however, are strategic considerations when the same firm operates multiple plants, particularly thermal, which may not be dispatched otherwise. In that case, scheduling the maintenance of a nuclear plant increases the probability that other plants are dispatched. The value of this decision is greater when the market price is higher.

In our model, e can capture this maintenance decision which, if interpreted as discrete, would imply $e = 1 - \beta$ if maintenance takes place when $p = 0$, and $e = 0$ if maintenance is independent of the market price.[14]

As moral hazard is the primary concern in this case, our model suggests that the compensation of the firm should partially depend on market prices to encourage the optimal timing for maintenance. A natural way to do so is to determine a strike price s based on the expected production of the plant, which would conform the fixed payment part, $F \equiv sE(q)$, and the lowest value of $\alpha^* \in (0, 1)$ that provides incentives to schedule maintenance of the plant when prices are low, giving rise to a total payment of $sE(p) + \alpha^* pq$.

To minimize the cost to consumers, the value of s should be the lowest amount that guarantees that the plant breaks even.[15] Consequently, the fixed payment $sE(q)$ could be potentially positive or negative, depending on whether market revenues exceed or fall short of the plant's costs. Since market revenues are not known at the time of writing the contract, the regulator might prefer to set $F \equiv (s - \alpha\tilde{p})E(q)$, where $\tilde{p}$ is the ex-post realized average market price, an approach that provides both buyers and sellers with price protection against fluctuations in expected market prices. The social value of this hedge is not fully captured in our model, as it assumes a constant expected production β and a constant expected market price.

It is worth noting that the most commonly used contracts for nuclear plants differ from the one outlined here. In most cases, nuclear power plants are subject to Contracts-

[14]The model assumes $e \geq 0$. However, it could easily accommodate effort decisions meant to increase production when prices are low so that, in the limit, $e = \beta - 1 < 0$.

[15]Whether extending the lifespan of an existing nuclear reactor or constructing a new one, there is typically only a single company involved, meaning competition cannot be relied upon to determine contract parameters. As a result, regulators must rely on complex financial models to set s, a process that is inherently challenging due to asymmetric information.

for-Differences (CfD), with a regulated strike price.[16] These contracts are typically settled based on metered output and the actual market prices received. Under this arrangement, the scheduling of maintenance ought to be determined by a third party, such as the system operator, to avoid inefficiencies in the absence of the price signal.

In contrast with the previous approach, in a recent State Aid decision regarding the construction of a new nuclear power plant in the Czech Republic (European Comission, 2024), the European Commission has agreed on a remuneration formula, $(s - \tilde{p})\, E(q) + pq$ that is close to the one outlined here, with the exception that the plant will be fully exposed to market prices, as $\alpha = 1$. Since full price exposure is risky, our analysis suggests that payments to the plant could have been reduced, to the benefit of consumers, by reducing $\alpha < 1$.

A key issue in the discussion is how to set the formula parameters to avoid overcompensation and under-compensation. From the expressions above, it should be clear that the nuclear power plant is overcompensated if s is set under the assumption that it operates at baseload (i.e., in our model, this would correspond to the firm exerting no effort, producing β both when $p = 0$ and $p = 1$). However, the formula actually incentivizes the plant to produce relatively more during high-price periods, implying that expected market revenues $E(pq)$ would exceed those assumed in the settlement term, $\tilde{p}E(q)$, giving rise to expected payments above $sE(q)$. Therefore, the choice of s should account for the plant's expected market revenues, considering the production decisions induced by the formula.

Renewable power plants Consider now intermittent renewable plants, such as solar or wind farms. Once location and technological choices have been made, these plants have limited ability to modify their production profiles, which are largely determined by weather conditions. However, these plants widely differ in their expected output, β, depending on the availability of the natural resource at the chosen location. Additionally, locations may vary in the investment costs of installing the plant, $C(\beta)$. This may be due, for example, to landowners setting a higher lease cost in resource-abundant areas.

The analysis of contract design for renewable technologies that share the same production profile but differ in their expected production can be captured through our adverse selection model, which assumes prohibitively high costs to shift production across time and heterogeneous values of β. In some cases, though, it is also relevant to consider con-

[16] For instance, in a recent decision, the EC (European Comission, 2025) has allowed Belgium to extend the lifetime of two nuclear reactors (Doel 4 and Tihange 3) under a Contract-for-Differences (CfD). The strike price of the contract is computed on the basis of a discounted cash flow model ensuring that the total aid amount is limited to the funding gap of the project. The operation of the plant is transferred to an independent energy manager. The new UK nuclear reactor, Hickley point, is also subject to a CfD with a regulated strike price (European Comission, 2014*a*).

tract design in cases where investors can affect the renewable plants' production profiles through location and technological choices (e.g., by investing in locations or technologies such that the availability of the resource is negatively correlated with market prices).

When production profiles cannot be modified, Lemma 4 suggests that high-production renewable plants should be compensated through a positive output payment, $f > 0$, rather than through market-price exposure. For the same expected remuneration, setting $f = 0$ and $\alpha > 0$ would induce a higher risk premium, while setting $f = 0$ and $\alpha = 0$ and basing the plants' entire remuneration on a capacity payment, would not allow for the selection of the most productive projects. Eliminating capacity payments, in turn, would make remuneration more reliant on output, which would overcompensate high-production projects and increase the plants' risk premium, ultimately borne by consumers. Hence, for intermittent renewable-energy plants that cannot modify their production profile, our model indicates that the optimal contract design combines both output and capacity payments, i.e., $f > 0$ and $F \neq 0$.

Notice that this result is based on the model assumption that prices never fall below zero. When this can occur, this contract design could induce inefficient production: as the plant is remunerated at $f > 0$, it keeps producing even if market prices fall below its (zero) marginal cost.[17] This distortion can be mitigated by setting a zero price floor, so that when the market price is negative, the plant is remunerated at that price, providing incentives to curtail production.

In practice, many commonly used contracts for solar and wind investments differ from the one described here. Initially, two support schemes were most prevalent: Feed-in-Tariffs (FiT), involving only a regulated fixed price for metered output (i.e., $F = 0$, $f > 0$, and $\alpha = 0$); or Feed-in-Premia (FiP), involving a fixed premium for metered output in addition to the market price (i.e., $F = 0$, $f > 0$, and $\alpha = 1$).[18] These are extreme cases, where the former does not allow for capacity payments, while the latter exposes investors to a high risk both related to price and output.

More recently, some renewable projects are carried out by merchant investors, who face full price exposure and receive no fixed output or capacity payments, thus failing in both dimensions. As discussed in previous sections, nowadays, a large proportion of new investments are executed under Power Purchase Agreements (PPAs) that vary in several ways, but most commonly include only a fixed output payment $f > 0$ based on the actual production (pay-as-produced), with $\alpha = 0$ and $F = 0$. However, as buyers

[17] This concern is acknowledge by the EC (European Commission, 2023) (para. 44), which requires Member States to ensure that the CfDs "*do not undermine the efficient, competitive and liquid functioning of the electricity markets, preserving the incentives of producers to react to market signals, including stop generating when electricity prices are below their operational costs*".

[18] Fabra and Imelda (2023) have compared the impact of these two contracts on market performance when some generators have market power.

seek to reduce their price exposure, some of these PPAs are evolving towards the so-called baseload contracts. In our framework, this is equivalent to $F > 0$, $f = 0$, and $\alpha > 0$, since the plant owner is exposed to market prices for the contract volume that it cannot meet with its own production.

In a recent decision, the EC (European Commission, 2023) has recently set a new obligation for Member States to use two-way Contracts-for-Difference (CfD) when supporting investments in renewable energies. CfDs are typically settled based on metered output and the actual prices received, corresponding to $F = 0$, $f > 0$, and $\alpha = 0$. In cases where setting $F > 0$ is optimal, our model suggests that these contracts would over-remunerate production, leading to excessive rents for high-production projects and positive risk premia due to output volatility.

The idea of not making the plants' remuneration fully linear in output to mitigate excessive rents for high-production sites has been implemented in Austria, the Netherlands, and Germany, where the strike price includes positive and negative adjustments for locations with low and high resource quality.[19] Similar effects are achieved when the contract duration is limited by a set number of operating hours, effectively replacing the output remuneration with a capacity remuneration, in the spirit of the Least-Present-Value-of-Revenue mechanism proposed for the financing of infrastructure (Engel et al., 2001). While this approach helps reduce rents at resource-abundant sites, it might also promote investment in resource-poor locations, particularly if the fixed costs of investing in those sites are lower.

In some instances, CfDs incorporate price exposure either directly through $\alpha > 0$, or indirectly through contract durations that are shorter than the lifetime of the asset. For example, the Spanish CfDs last for 12 years, typically about half of the plants' expected lifetimes, and include $\alpha = 0.1$, with f determined through auctions. Once the contract expires, the plants are fully exposed to market prices.

Alternatively, a CfD can be settled based on an exogenous reference price, $\tilde{p}$, resulting in revenues of $(s - \tilde{p})q + pq$. These are the so-called CfDs with a sliding premium, involving $F = 0$, full price exposure with $\alpha = 1$, and a per-unit output payment of $f = s - \tilde{p}$. An example of this contract design is used in Germany, where the reference price is the average market price received over a month by all renewable plants of the same technology. The positive correlation between the plant's captured market price and the contract's reference price reduces risk exposure. Conditioning on rivals' captured prices provides additional incentives to exert effort, in the spirit of yardstick competition (Shleifer, 1985). To the extent that moral hazard is present — e.g., if firms can influence their production profile through costly effort — these contracts have the advantage of incentivizing

[19] In Germany, this correction model is referred to as the *Reference Yield Model* (Kröger et al., 2022).

investors to choose sites or technologies that provide more valuable production.

Finally, if the CfD is computed using an exogenous output reference k, it results in revenues of $(s - \widetilde{p})k + pq$. In our framework, this corresponds to a fixed payment $F = (s - \widetilde{p})k$ and no remuneration based on actual output, together with $\alpha = 1$. This structure when $k = E(q)$ is in line with the nuclear remuneration formula proposed by the EC for the Dukovany nuclear reactor, as described above. However, this price exposure may be seen more inadequate in this context, given that intermittent renewable plants cannot influence their availability to the same extent as nuclear power plants can through maintenance decisions.

Finally, our moral hazard and adverse selection models can be combined to provide insight into several other relevant cases, where effort choices influence both the production profile and expected production. For instance, installing solar trackers allows solar panels to produce more throughout the day, with a relatively greater increase during the early hours of sunrise and the late hours of sunset. The key takeaway is that moral hazard issues are better addressed with price exposure, whereas adverse selection issues are more effectively tackled with fixed per-unit output payments. In both cases, capacity payments play an important role, as they allow remuneration without introducing risk, which can be costly and discourage effort, while also helping to mitigate rents. The optimal contract in each scenario combines these elements based on the relative importance of moral hazard and adverse selection, given the specific attributes of each technology.

This takeaway is also relevant for the comparison between technology-neutral and technology-specific mechanisms. Fabra and Montero (2022) have compared the two approaches, concluding that, while technology-neutral mechanisms are effective at selecting the most efficient projects, they may result in high rents for the most productive ones. In particular, if competing projects are highly asymmetric and regulators are sufficiently well-informed about the costs and social value of the various technologies, relying on technology-specific mechanisms might lead to welfare improvements. The analysis in this paper provides an additional argument to this debate: since the optimal contract design varies with the attributes of each technology, applying a technology-neutral approach among technologies with different attributes could be counterproductive.

6 Conclusions

The design of long-term contracts plays a crucial role in fostering low-carbon investments by mitigating the price and quantity volatility they face under spot market trading. This paper underscores the importance of contract mechanisms that provide partial risk hedging to both derisk the investments as well as to ensure the efficient deployment and operation of renewable and nuclear energy projects. Our analysis reveals that a one-size-fits-all approach is suboptimal, as different technologies require tailored contract structures based on their attributes; specifically, whether they introduce challenges related to moral hazard, adverse selection, or both.

Policy interventions that promote Contracts-for-Differences (CfDs) can help alleviate liquidity constraints in long-term contracting markets while addressing the root causes of underlying market failures, such as counterparty risk. Promoting Power Purchase Agreements (PPAs) would expand available contracting options. However, regulators should remain vigilant regarding potential distortions, such as excessive counterparty risk, which inflate contract prices, and the partial pass-through of these costs to final consumers, particularly in markets with weak retail competition.

Our findings suggest that technology-specific contracts, rather than strictly technology-neutral mechanisms, may be essential to promote efficient investment and production decisions while minimizing financial burdens on consumers.

Appendix: Proofs

Proof of Lemma 1. The positive effect of f, α, and r is immediate. Regarding the other results, we can compute

$$\frac{\partial R}{\partial e} = \frac{\alpha r}{2}\left[1 - \alpha(e+\beta) + 2f(1-\beta)\right] > 0,$$
$$\frac{\partial R}{\partial \beta} = \frac{r}{2}\left[\alpha(\alpha+2f)(1-e-\beta) - 2f(\alpha\beta - f + 2\beta f)\right].$$

Taking the derivative with respect to β and e,

$$\frac{\partial^2 R}{\partial^2 e} = -\frac{\alpha^2 r}{2} < 0,$$
$$\frac{\partial R}{\partial e \partial \beta} = -\frac{\alpha r(2f+\alpha)}{2} < 0,$$
$$\frac{\partial^2 R}{\partial^2 \beta} = -\frac{r(2f+\alpha)^2}{2} < 0.$$

□

Proof of Lemma 2. In the text. □

Proof of Lemma 3. The expected utility of investors is

$$U(\beta, e) = F + f\beta + \alpha\frac{\beta+e}{2} - r\alpha^2\frac{\beta+e}{2}\left(1 - \frac{\beta+e}{2}\right) - C(\beta, e).$$

The first-order derivative with respect to effort can be written as

$$\frac{\partial U}{\partial e} = \frac{1}{2}\alpha\left(1 - r\alpha\left(1 - (\beta+e)\right)\right) - ce,$$

while the second derivative and cross-derivatives are,

$$\frac{\partial^2 U}{\partial e^2} = \frac{1}{2}r\alpha^2 - c < 0,$$
$$\frac{\partial U}{\partial e \partial \beta} = \frac{1}{2}r\alpha^2 > 0.$$

At $e = 0$, expected utility is decreasing in effort if $\beta < \underline{\beta} \equiv 1 - \frac{1}{r\alpha}$. Hence, optimal effort is $e^* = 0$. For $\beta \geq \underline{\beta}$, the interior solution is given by

$$e^* = \frac{1}{2}\frac{\alpha\left(1 - r\alpha\left(1-\beta\right)\right)}{c - \frac{1}{2}r\alpha^2} > 0.$$

For an interior solution, we need $\beta + e^* \leq 1$, so that

$$\beta + e^* = \beta + \frac{1}{2}\frac{\alpha\left(1 - r\alpha\left(1-\beta\right)\right)}{c - \frac{1}{2}r\alpha^2} \leq 1,$$

which is satisfied if $\beta \leq \overline{\beta} \equiv 1 - \frac{\alpha}{2c}$. Since e^* is increasing in β, it follows that for $\beta > \overline{\beta}$, we obtain a corner solution at $e^* = 1 - \beta$. □

Proof of Proposition 1. The derivative of social welfare with respect to α can be written as

$$\frac{dW}{d\alpha} = \frac{1}{2}(1-\alpha)\frac{\partial e^*}{\partial \alpha} - 2\alpha R(\beta, e; \alpha, 0),$$

which gives rise to (4) when the solution is interior and determines, in that case, the optimal value α^*.

We can rule out the situation with $\alpha^* = 1$ as this would lead to

$$\frac{dW}{d\alpha} = -2R(\beta, e; 1, 0) < 0,$$

implying that welfare could increase by lowering α.

Suppose now, towards a contradiction, that $\alpha^* = 0$. As this would imply no risk, the derivative of the social welfare would have the same sign as $\frac{\partial e^*}{\partial \alpha}$. In an interior solution for effort,

$$\left.\frac{\partial e^*}{\partial \alpha}\right|_{\alpha=0} = \frac{1}{2c} > 0,$$

which would be incompatible with $\alpha^* = 0$. Hence, e^* must be either 0 or 1. Suppose that $e^* = 0$. From Lemma 3, this implies $\beta < \underline{\beta} = 1 - \frac{1}{r\alpha^*} = 0$ which is a contradiction. Finally, suppose that $e^* = 1 - \beta$. Also from Lemma 3, this would require $\beta > \overline{\beta} = 1 - \frac{\alpha^*}{2c} = 1$ which is, again, a contradiction. □

Proof of Lemma 4. Suppose that $\beta > 0$ is observable. In the choice between f and α, the objective function of the regulator can be written as

$$\max_{(f,\alpha)} \; (1-\alpha)\frac{\beta}{2} - f\beta - F + \gamma\left[u(\beta) + F\right],$$
$$\text{s.t. } u(\beta) = \bar{u}.$$

The Lagrangian of this problem becomes

$$\mathcal{L} = (1-\alpha)\frac{\beta}{2} - f\beta - (1-\gamma)F + (\gamma+\lambda)u(\beta) - \lambda\bar{u},$$

where $\lambda \geq 0$ is the Lagrange multiplier. The derivatives with respect to α and f become

$$\frac{\partial \mathcal{L}}{\partial \alpha} = -\frac{\beta}{2} + (\gamma+\lambda)\left[\frac{\beta}{2} - r\beta\left(f(1-\beta) + \frac{\alpha(2-\beta)}{2}\right)\right],$$
$$\frac{\partial \mathcal{L}}{\partial f} = -\beta + (\gamma+\lambda)\left[\beta - r\beta(1-\beta)(2f+\alpha)\right].$$

Combining the previous expressions we obtain that

$$\frac{\partial \mathcal{L}}{\partial \alpha} = \frac{1}{2}\frac{\partial \mathcal{L}}{\partial f} - (\gamma+\lambda)r\frac{\alpha\beta}{2}.$$

This means that if the optimal per-unit price f is positive, arising from $\frac{\partial \mathcal{L}}{\partial f} = 0$, then $\frac{\partial \mathcal{L}}{\partial \alpha} < 0$ and $\alpha^* = 0$. If the optimal f is 0, then $\frac{\partial \mathcal{L}}{\partial f} < 0$, which also implies $\frac{\partial \mathcal{L}}{\partial \alpha} < 0$ and, again, $\alpha^* = 0$. □

Proof of Proposition 2. In the text. □

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