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DIW Berlin
German Institute for Economic Research
Anton-Wilhelm-Amo-Str. 58
10117 Berlin

Tel. +49 (30) 897 89-0
Fax +49 (30) 897 89-200
<http://www.diw.de>

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Hedging as a Match-Maker: Unlocking Industrial Demand Flexibility for Renewable Energy Integration*

Paula Prakash^{†‡} Leon Stolle[†]

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Abstract

We analyze how long-term electricity hedging design affects industrial investments in load-shifting capacity. These investments enable flexible electricity consumption and play a crucial role in integrating variable renewable energy. We develop a theoretical model of flexibility investment by a risk-averse industrial firm facing uncertainty about renewable generation and electricity prices. We compare a conventional baseload hedge with a renewable energy profile (REP) hedge, a hedge with a fixed price but varying quantity proportional to renewable generation. The key difference is the consumer’s risk exposure and how it affects flexibility investment. Under the baseload hedge, flexibility provides an uncertain arbitrage value from shifting consumption across hours, so risk aversion reduces investment. Under the REP hedge, flexibility acts as a physical hedge against renewable profile risk by aligning the firm’s consumption with the contracted profile. This insurance value can increase flexibility investment under risk aversion. Numerical simulations illustrate the mechanism for realistic hourly price and renewable generation profiles. We further show that the REP hedge can reduce risk-adjusted total costs for flexible firms once baseload contract prices reflect observed profile risk premia. The results identify long-term hedging design as a potential channel to unlock industrial demand-side flexibility.

Keywords: Industrial demand response, long-term contracts, renewable energy, investment, risk aversion, profile risk

JEL-Codes: Q41, Q48, D21, D81

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[†]DIW Berlin and Technical University Berlin.

[‡]Corresponding author. Email: pprakash@diw.de.

1 Introduction

Decarbonizing electricity systems requires replacing fossil generation with variable renewable energy (VRE). As renewable output does not always coincide with electricity demand, increasing VRE penetration raises the need to shift electricity supply and demand across time. At the same time, dispatchable fossil plants that have historically provided such flexibility are gradually displaced, creating a flexibility gap (Papaeftymiou et al., 2018).

Industrial demand-side flexibility in the form of load shifting, where firms adjust electricity consumption around a baseline, can be valuable to address this flexibility gap. Such flexibility typically requires an up-front investment in storage capacity, for example for heat, intermediate products, or batteries. Once installed, it can provide low-cost, low-emission balancing of demand and supply by shifting consumption away from scarcity hours to hours with high renewable generation. This can reduce peak prices, curtailment, the need for power generation capacity, and grid expansion (Kim and Shcherbakova, 2011; Gils, 2016). On a firm-level, demand-side flexibility can decrease electricity costs by arbitraging between high and low-cost hours (Herre et al., 2020; Adetunji et al., 2025). Despite these benefits and substantial technical potential, only a small share of demand-side flexibility is currently unlocked (Howard et al., 2021).

One reason for this under-utilization is that incentives for flexibility investment depend on how firms procure electricity (Lund et al., 2015). Large industrial consumers typically cover a substantial share of electricity demand in advance on forward and futures markets to hedge price risk and ensure budget certainty. While such hedging reduces exposure to volatile spot prices, it can also weaken the firm’s value of shifting demand across hours (Lund et al., 2015; Arellano and Carrión, 2023). Electricity procurement therefore not only determines the level and volatility of electricity costs, but may also influence incentives for demand-side flexibility.

We study this relationship by examining how different long-term contract designs allocate risk to the industrial consumers, and how this affects incentives to invest in demand-side flexibility. In particular, we distinguish between price risk, volume risk, and profile risk (Simões et al., 2025). Spot procurement without any hedging leaves the firm exposed to price risk, as all consumption is settled at the spot price. Long-term hedges reduce this exposure by fixing the price for a contracted quantity, but differ in the delivery profile they provide. The most liquid hedging products are baseload contracts, which provide a constant hourly quantity of electricity at a fixed price (EEX, 2025).

With rising VRE shares and declining fossil generation, however, baseload-shaped delivery becomes increasingly costly to provide, as reflected in higher risk premia (BloombergNEF, 2022). We therefore consider a renewable energy profile (REP) hedge that fixes the price but supplies a time-varying quantity proportional to renewable generation. This shifts the consumer’s exposure from a flat profile toward a renewable profile. This increases the profile risk, i.e. the risk that the contracted delivery profile does not match the firm’s consumption profile. The consumer may additionally face inter-annual volume risk, as renewable output varies across years. Flexibility can then become valuable not only for arbitraging spot-price differences, but also for mitigating mismatches between renewable-profile delivery and the firm’s consumption needs.

To investigate incentives from these different contracts, we develop a two-stage model of investment under uncertainty. In the first stage, a representative industrial firm makes an

irreversible investment in flexibility capacity under risk aversion. Risk aversion reflects that flexibility is not part of the industrial firm’s core business and involves uncertain returns. In the second stage, after renewable output and spot prices are realized, it uses this flexibility capacity to shift consumption across periods while keeping annual production fixed. We first compare a baseload hedge and a REP hedge analytically. We then extend the analysis in a numerical application to the pulp and paper industry (PPI) using simulated hourly German electricity prices and renewable generation from [Klaucke et al. \(2026\)](#).

We identify a theoretical mechanism through which hedge design and risk aversion interact. Under a baseload hedge, flexibility mainly provides uncertain arbitrage revenues from shifting consumption across hours; risk aversion therefore reduces investment. We label this the ‘arbitrage effect.’ Under a REP hedge, flexibility additionally provides insurance against renewable profile risk, because it helps the firm align its consumption with the contracted renewable delivery profile. We label this the ‘exposure effect.’ The actual effect on flexibility investment under the REP hedge therefore depends on the relative strength of these two effects. The exposure effect increases investment relative to the risk-neutral benchmark and the risk-averse baseload firm. This happens when investment costs are sufficiently high to keep flexibility investment at levels where its marginal risk-reduction value remains substantial.

In the numerical analysis, we show that under conventional assumptions about investment costs the exposure effect dominates and leads to higher flexibility investments by a risk-averse firm under the REP hedge compared to a firm under a baseload hedge. Furthermore, we show that the combination of a REP hedge and optimal flexibility investment decreases risk-adjusted total costs compared to the baseload firm, already under currently observed baseload risk premia.

These findings have direct policy implications. Current policy and market-design choices will affect how the flexibility gap is filled. Exposing industrial consumers to renewable profile risk through hedges with a renewable profile, for example through EU tripartite energy agreements ([European Commission, 2026b](#)), could increase investment in demand-side flexibility. This could reduce the need for a continued build-up of supply-side flexibility such as gas-fired power plants.

Our contribution is twofold. First, we contribute to the literature on long-term electricity contracting, and its effect on risk allocation and investment incentives. A broad theoretical literature shows that limited opportunities to hedge long-term electricity-market risks (‘incomplete electricity markets’) can affect risk exposure and investment decisions of investors in generation capacity (see e.g., [Ehrenmann and Smeers, 2011](#); [de Maere d’Aertrycke et al., 2017](#); [Dimanchev et al., 2024](#); [Abada, 2026](#)). Related studies focus on renewable generation and show how long-term contracts affect investment incentives through risk allocation and financing conditions. [Newbery et al. \(2018\)](#) highlight the importance of long-term contracting design in markets with high shares of renewable generation for reducing risk and the cost of capital. [May and Neuhoff \(2021\)](#) quantify how renewable-support policies, which essentially are long-term contracts, reduce financing costs of renewables by addressing regulatory and market risks. [Neuhoff et al. \(2022\)](#) find that contracts for difference (CfDs) provide a comparatively effective hedge against electricity-price uncertainty for both renewable investors and consumers. At the same time, [Favre and Roques \(2023\)](#) emphasize the fundamental trade-off in contract design: protecting

investors from market-price risk lowers financing costs but may weaken incentives to respond efficiently to short-term price signals. Recent work further shows that contracting one asset can also affect investment incentives in complementary assets, depending on how risk is allocated: [Soumoy et al. \(2026\)](#) find that hedging renewable generators can reduce battery investment by replacing part of the natural-hedging value otherwise provided by storage. We build on this insight and shift attention to the demand side: rather than studying investment in the contracted generation asset, we examine how the design of an electricity-procurement contract affects the offtaker’s incentives to invest in flexibility.

We further add to this literature by explicitly accounting for the effects of risk aversion. [Munoz et al. \(2017\)](#) show that renewable investment can hedge exposure to uncertain fuel and operating costs, while [Möbius et al. \(2023\)](#) demonstrate that flexibility options have an additional risk-reduction value for risk-averse decision-makers. We confirm this general risk-reduction mechanism in a firm-level investment setting but show that its investment effect is conditional on the interplay between arbitrage and insurance value.

Second, we contribute to the literature on industrial demand response. Existing studies examine how electricity-market and policy design affect both the utilization of existing flexibility and incentives to invest in additional flexibility. [Richstein and Hosseinioun \(2020\)](#) analyze how network tariffs and participation rules in different electricity markets affect flexibility investment in and operation of a chlor-alkali process. They show that fixed network tariffs based on peak demand can substantially suppress flexibility utilization. From a system perspective, [Ambrosius et al. \(2018\)](#) show that the welfare effects of industrial demand flexibility depend on its spatial allocation and on the underlying pricing regime. Comparing uniform and locational pricing, they find that locational price signals improve the allocation of flexible industrial demand and thereby affect electricity costs, network expansion, and generation investment. Further contributions examine industrial demand response in reserve markets ([Ramin et al., 2018](#); [Devine et al., 2019](#); [Bohlayer et al., 2020](#)), its interaction with congestion management ([Rövekamp et al., 2023](#)), and its treatment under capacity mechanisms ([Lynch et al., 2019](#)). Whereas this literature focuses primarily on market and regulatory conditions under which flexibility is operated and remunerated, we examine a preceding electricity procurement decision: how a firm’s long-term hedge shapes its residual risk exposure and thereby its ex ante incentive to invest in flexibility.

The rest of the paper is structured as follows. In Section 2, we provide background information on long-term contracts for electricity and demand-side flexibility. Section 3 gives first intuition on how contract design and risk aversion affect investments. In Section 4, we introduce the analytical model, presenting the results in Section 5. We further investigate the model’s mechanisms in Section 6 through a numerical simulation. Section 7 concludes with a discussion and policy implications.

2 Institutional Setting

2.1 Long-term contracts in electricity procurement

Large industrial consumers typically enter long-term contracts to reduce their exposure to spot price variations and thus hedge their electricity costs ([Lund et al., 2015](#)). These can be exchange-

traded products or bilateral contracts including power purchase agreements (PPAs).

A consumer that procures electricity with a REP hedge, as introduced in this paper, pays a fixed price for an amount of electricity that co-moves with renewable generation, as depicted in Figure 1. This stands in contrast to the prevalent baseload hedge, which guarantees a constant amount of electricity, irrespective of the general market conditions. The key difference between baseload and REP contracts is thus the shape of the contracted profile. Any deviation between the firm’s actual consumption profile and the contracted profile is settled at spot prices, exposing the consumer to profile risk (Simões et al., 2025). Consumers can mitigate this risk by investing in and utilizing flexibility that reduces residual imbalances (Chod et al., 2010).

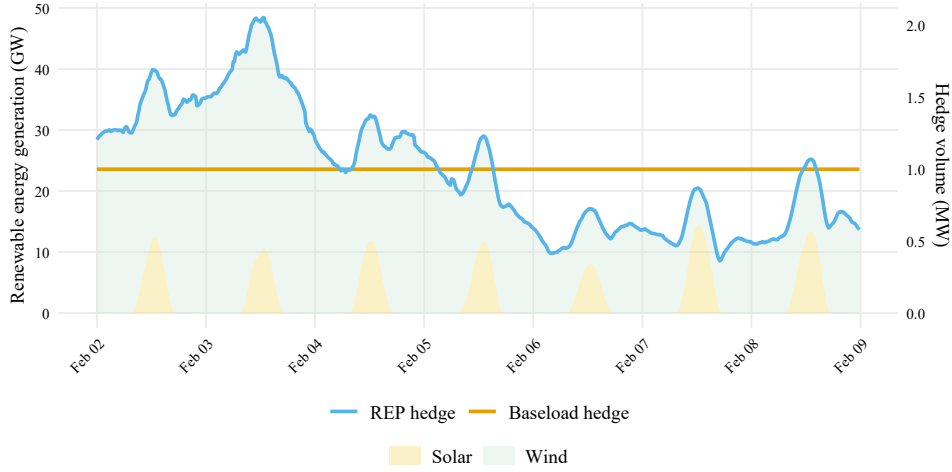


Figure 1: Derivation of the REP hedge from renewable production

Note: German renewable generation (left axis) for an exemplary week in February 2026 (data from [Fraunhofer ISE \(2026\)](#)). The volume of the REP hedge is defined as a share from renewable production with an average volume of 1 MW (right axis). Across the displayed week both hedges deliver the same amount of electricity.

Features of the REP hedge can already be found in existing contracts and newly proposed product types. For example, in pay-as-produced PPAs, the consumer agrees to buy all or a fixed share of the generation of a renewable energy plant at a fixed price. The variability of generation from a single renewable energy plant can be quite high, which can lead to substantial risk of a mismatch between generation and the offtaker’s demand. [Gabrielli et al. \(2022\)](#) show that a PPA portfolio across different technologies and locations can decrease this risk. This feature is picked up by [Neuhoff et al. \(2025\)](#) in their proposal of a renewable energy pool, in which renewable energy plants on CfDs are aggregated, and the average conditions passed on to consumers. It is similar to the recent EU proposal for tripartite energy agreements ([European Commission, 2026b](#)).

2.2 Demand flexibility in electricity markets

Flexibility is a key complement to VRE. As intermittent wind and solar output increase, electricity systems face larger temporal mismatches between renewable supply and demand. This mismatch can be addressed through four different options of flexibility: supply-side, storage-based, network-side, and demand-side flexibility ([Leinauer et al., 2022](#); [Cruz et al., 2018](#)). In this paper, we focus on demand-side management, defined as the ability to shift electricity de-

mand across time to address fluctuating supply while keeping total consumption fixed (Heffron et al., 2020).

Technical potential. The industrial sector consumed 36% of global electricity in 2022 (IEA, 2023). Coupled with installed infrastructure that enables load shifting, this makes the industrial sector particularly relevant in providing demand-side flexibility (Gils, 2014). Estimates of the technical potential of industrial demand response vary across publications. For example in Germany, Fleiter et al. (2024) estimate 4.9 GW of load reduction and 1.1 GW of load increase potential for a shifting period of four hours, based on a review of existing literature. Considering a broader set of processes and including cross-cutting technologies, SynErgie (2024) estimate 9.2 GW reduction and 9.1 GW increase potential for a four-hour period.

Economic benefits. This technical potential directly translates into opportunities for economic benefits. On a plant-level basis, Summerbell et al. (2017) estimate that a flexible production schedule can yield electricity cost savings of 4.2% for a UK cement plant. Yu et al. (2018) estimate cost-saving potential between 6.5% and 8.2% for industrial consumers. From a system perspective, industrial demand response could substitute up to 10 GW of fossil power plant capacity in Germany (Gils, 2016). Because demand response is mostly used to shave peak demand, this substitution can lower total electricity generation costs by 1.4%–3.6% relative to a scenario without demand response. Further benefits include lower emissions (Golmohamadi, 2022; Förster et al., 2024; Gabrek and Seifermann, 2025) and reduced grid expansion needs (Kim and Shcherbakova, 2011).

Barriers. Despite the technical potential and benefits of demand flexibility in the industrial sector, most of it remains untapped (DG Competition, 2024). Several studies identify barriers through literature reviews and stakeholder interviews. Key barriers that affect investment incentives and risk allocation considered in this paper can be grouped into four categories.

First, barriers are created through muted price exposure and weak incentives. A natural revenue channel for flexibility is to exploit spot price dispersion via price arbitrage, shifting electricity consumption from high- to low-price hours. This incentive is often muted in part because many industrial consumers rely on long-term fixed-price procurement and have limited exposure or access to spot markets (Lund et al., 2015; Mays, 2021). Second, revenue uncertainty and missing risk markets limit demand-side flexibility: A major barrier is uncertain and volatile revenues from flexibility (Scharnhorst et al., 2024). Coupled with up-front investment needs, this uncertainty can increase the cost of capital and strengthen the role of efficient risk allocation (DG Competition, 2024). Third, there are transactional and organizational frictions: Participation in flexibility provision often requires metering, forecasting, baseline measurement, and operational coordination, which create fixed costs and may be subject to organizational inertia (Leinauer et al., 2022). Finally, tariff and market design frictions occur: Network tariffs and market rules can reduce profitability of load shifting, for example when grid tariffs are determined by peak demand, such as within the German industrial baseload privilege (Richstein and Hosseinioun, 2020; Buhl et al., 2025). Additionally, participation rules can limit access to

balancing and flexibility markets (ACER, 2023).

These barriers indicate that while industrial demand flexibility is both technically available and valuable from a firm- and system perspective, it does not imply that firms have sufficient incentives to invest in flexibility. The proposed REP hedge could contribute to addressing this by embedding incentives for flexibility within a long-term procurement structure through exposure to profile risk.

3 The Economics of Contract Design and Flexibility Investment

To provide first intuition on how contract design affects flexibility investments under risk aversion, we illustrate the optimal investment decision in a stylized marginal benefit (MB) — marginal cost (MC) framework. Firms invest in flexibility until the marginal benefit of an additional unit equals its marginal cost. We distinguish between (i) risk-neutral and risk-averse investors, and (ii) the baseload hedge and the REP hedge. The intuition is sketched in Figure 2.

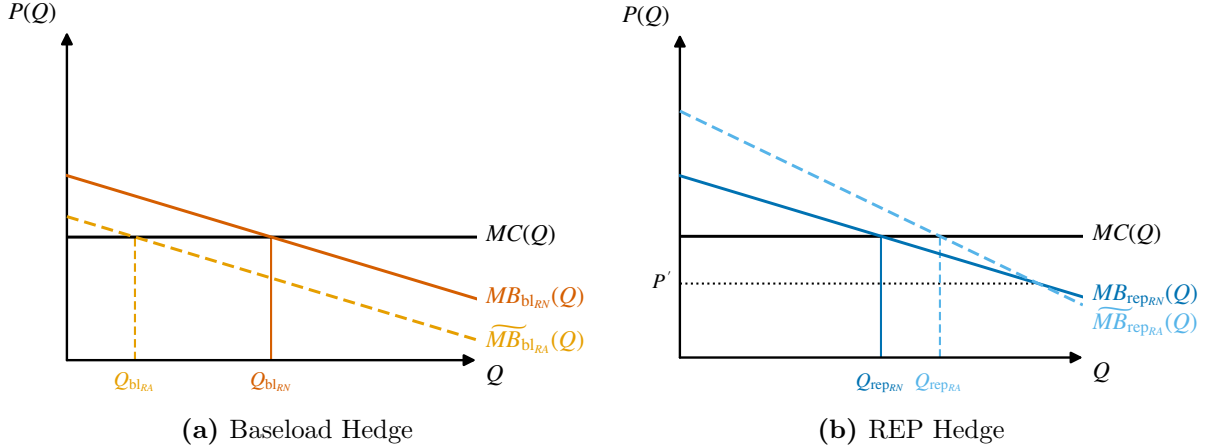


Figure 2: Optimal Investment Levels

Note: The reference investment levels are derived from risk-neutral marginal benefits (MB) and marginal costs (MC), depicted by the solid lines. The dashed lines represent the effects of accounting for risk aversion. $Q_{bl_{RN}}$, $Q_{rep_{RN}}$, $Q_{bl_{RA}}$ and $Q_{rep_{RA}}$ indicate the optimal investment levels, respectively. P' indicates the marginal cost level of investments above which the REP-hedge generates higher investments for risk-averse investors compared to their risk-neutral counterparts.

We assume marginal investment costs to be constant and thus represented as a horizontal line. Because investment costs are incurred upfront and are not subject to uncertainty, they are not affected by the level of risk aversion. Furthermore, the marginal cost curve is not affected by the contract structure. Benefits of flexibility arise from the ability to shift electricity consumption across hours and thereby arbitrage spot-price differences. Because the benefits accrue only after the investment and depend on the realization of electricity price spreads, the benefits are uncertain and potentially affected by risk aversion. Marginal benefits are decreasing in the level of flexibility.

Under risk neutrality, the marginal benefits of flexibility are identical for the baseload and REP firm. Flexibility creates an ‘arbitrage value’ by allowing the firm to shift consumption from high-price to low-price hours. This arbitrage value depends only on the spot-price spread.

If both firms shift load across hours the same way, the expected marginal benefit of additional flexibility is equal for the two firms. However, uncertain benefits of risky projects discourage investments by risk-averse investors. These investors require a higher expected return to invest in an asset with a risky return, which also holds true for investments in flexibility and the uncertain arbitrage profits. The marginal benefit curve thus shifts downward. A risk-averse firm with a baseload contract is exclusively affected by this ‘arbitrage effect’ and hence reduces optimal flexibility investment compared to its risk-neutral counterpart (Figure 2a).

Introducing risk aversion for the REP-hedged firm generates two competing effects. While risk-averse investors still require a higher expected return to invest in risky assets, flexibility also has an ‘insurance value’ under the REP hedge. As the REP hedge shifts the profile risk of renewables to the electricity consumer, the insurance value of flexibility arises as a physical hedge against this profile risk. The insurance value is most pronounced at low levels of flexibility, when the firm remains highly exposed to renewable profile risk, and declines as flexibility capacity increases. Hence, under the REP hedge, risk aversion not only shifts the marginal benefit curve, but also changes its slope, inducing a clockwise rotation (Figure 2b). As illustrated, risk-averse firms under the REP hedge invest more in flexibility than their baseload-hedged counterparts.

The key implication is that the relative investment effect of the REP hedge under risk aversion depends on the costs of investing in flexibility. At low investment costs, firms invest sufficiently in flexibility and exploit most arbitrage opportunities. At higher investment costs, however, investment decisions are more strongly affected by the exposure effect: Flexibility reduces exposure to unfavorable deliveries under the REP hedge rather than merely generating uncertain arbitrage gains. The REP hedge therefore induces more flexibility investment relative to the baseload hedge particularly when flexibility investment costs are high.¹

4 The Model

We develop a two-stage investment and production model with an exogenously given contract environment to study how different electricity procurement contracts c affect an industrial firm’s incentive to invest in operational flexibility (see Figure 3 for a visual representation of the model). In the first stage $s = 1$, it chooses an irreversible flexibility investment F , e.g. load-shifting capacity. It allows the firm to vary electricity consumption q_{yt} within a wider band around baseline demand while keeping annual consumption fixed. In the second stage $s = 2$, after renewable output and prices have been realized, the firm partially shifts consumption towards low-price hours, trading off resulting electricity cost savings against adjustment costs. In the contract environment $s = 0$, the firm is exogenously assigned a long-term hedge for electricity. We compare a baseload hedge with a REP hedge. Further, we vary the level of risk aversion of the industrial firm, modeled using the conditional value at risk (CVaR). Appendix A lists all variables and parameters of the model.

¹Throughout, ‘exposure effect’ denotes the formal REP-specific mechanism through which the ‘insurance value’ of flexibility affects operating cost.

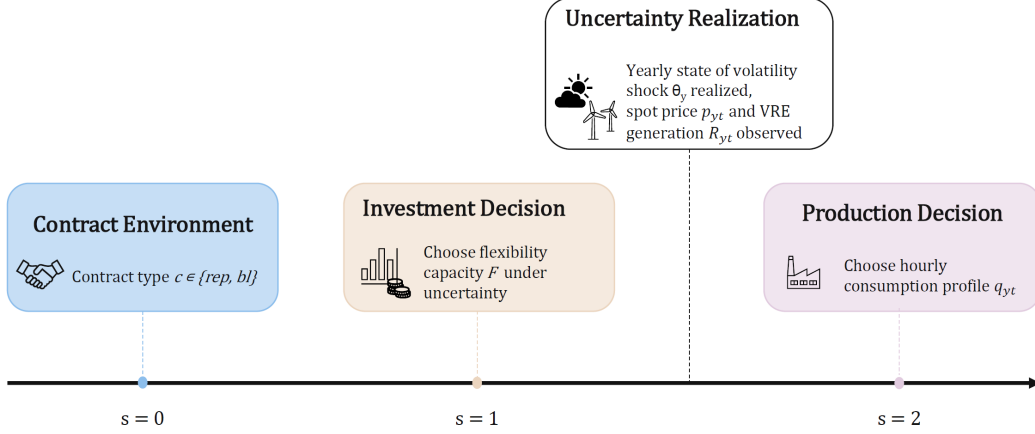


Figure 3: Timeline of the analytical model

4.1 Renewable energy supply and spot prices

We model the variability of renewable energy supply in line with the integration-cost framework of [Hirth et al. \(2015\)](#). We distinguish between (i) intra-annual variability of renewable output (see Figure 4a) and (ii) inter-annual uncertainty about its magnitude.² Renewable generation R_{yt} and spot prices p_{yt} are given by:

$$R_{yt} = \bar{R} + \theta_{yt} \quad (1)$$

$$p_{yt} = \bar{p} - \beta \theta_{yt} \quad (2)$$

where $\theta_{yt}|\theta_y \sim \mathcal{U}(-\theta_y, \theta_y)$ and $\theta_y \sim \mathcal{U}(\underline{\theta}, \bar{\theta})$, with $0 < \underline{\theta} < \bar{\theta}$

The volatility shock θ_{yt} captures deviations of VRE generation around its mean $\bar{R}$, which varies for every period t within a year y .³ Similarly, electricity spot prices are determined by the base price $\bar{p}$ and the same intra-annual volatility shock, scaled by β . The parameter $\beta > 0$ governs the magnitude of the negative correlation of renewable supply and prices: higher renewable output decreases spot prices ([Hirth, 2013](#)). Inter-annual uncertainty about the variability is represented by θ_y , which scales the intra-annual variance of renewable generation and electricity prices. Larger realizations of θ_y thus correspond to years with greater intra-annual variability and more pronounced profile effects.

4.2 The representative firm

We first define the two contract types that are assigned to the firm in $s = 0$. We proceed to describe the investment problem in $s = 1$ and the production problem in $s = 2$.

²[Hirth et al. \(2015\)](#) consider forecast errors of RE generation between the day-ahead and real-time as the main source of uncertainty. In contrast, we model inter-annual uncertainty about the magnitude of intra-annual variability and thus profile effects.

³In the analytical model, t denotes continuous within-year time. In the numerical model, t denotes hours. We use “period” in the analytical sections and “hour” in the numerical application.

Electricity procurement options. The firm procures electricity through one of two contract types $c \in \{rep, bl\}$. We represent each procurement option by a hedged quantity profile q_{yt}^c and a corresponding contract price p^c . Any deviation between the firm's period- t electricity consumption q_{yt} and the contracted quantity q_{yt}^c is traded on the spot market at the realized spot price p_{yt} . This formulation allows the firm to either buy additional electricity when $q_{yt} > q_{yt}^c$ or to sell excess contracted electricity when $q_{yt} < q_{yt}^c$.

Under a baseload hedge, the firm has a long-term contract for a constant hourly quantity equal to its baseline consumption, $q_{yt}^{bl} = \bar{q}$ at a fixed price p^{bl} . Under a REP hedge, the firm has a time-varying quantity as a share η of hourly renewable generation profile, $q_{yt}^{rep} = \eta R_{yt}$, at a fixed price p^{rep} .⁴ Hence, contracted REP electricity co-moves with renewable generation: the firm receives more electricity in high-renewable hours and less in low-renewable hours.

Investment stage. The firm chooses its flexibility investment level F such that total costs $TC^c(F)$ are minimized. The firm makes the investment decision in expectation of how flexibility will be used in the production stage, but only knows the probability distribution of the annual volatility shock θ_y (and hence the distribution of annual operating costs). The firm's investment decision therefore trades off higher investment expenditures against expected operating cost savings from being able to shift electricity consumption in the production stage.

The investment problem is therefore:

$$\min_{F \geq 0} TC^c(F) = g(F) + (1 - \omega) \mathbb{E}_y[OC_y^c(F)] + \omega \text{CVaR}_\alpha(OC_y^c(F)). \quad (3)$$

Total costs consist of annualized investment costs $g(F) = \lambda \cdot F$ with $\lambda > 0$ and a risk-adjusted assessment of minimized operating costs $OC_y^c(F)$ (defined below). The solution to (3) yields the optimal flexibility investment level under each procurement contract. To account for risk-averse investment behavior, we assume that the firm evaluates annual operating costs using a CVaR criterion (Rockafellar and Uryasev, 2000). It is modeled by a convex combination of expected annual operating costs $\mathbb{E}_y[OC_y^c(F)]$ and the CVaR_α , which is the average of the worst $(1 - \alpha) \cdot 100\%$ realizations of operating costs. The parameter $\alpha \in (0, 1)$ determines the tail probability considered in the CVaR, whereas $\omega \in [0, 1]$ describes the weight put on the CVaR. The degree of risk aversion of the firm thus increases in both ω and α . In its investment decision, the risk-averse firm thus places additional weight on the worst realizations of operating costs.

Production stage. At the beginning of the production stage, the annual volatility shock θ_y has realized and, under the assumption of perfect foresight of intra-annual supply and price variability, the firm observes the full within-year path of renewable output and spot prices $\{R_{yt}, p_{yt}\}_{t \in [0, T]}$, and thus its hedged electricity quantity q_{yt}^c . Given this and the flexibility level F , the firm chooses its hourly electricity demand profile $\{q_{yt}\}_{t \in [0, T]}$ to minimize hourly operating costs OC_{yt}^c :

$$OC_{yt}^c = p^c q_{yt}^c + p_{yt}(q_{yt} - q_{yt}^c) + h(q_{yt}), \quad \forall c \in \{rep, bl\}. \quad (4)$$

⁴For ease of notation, we normalize average renewable generation to resemble baseline consumption $\bar{R} = \bar{q}$ and set $\eta = 1$. This is equivalent to measuring renewable generation in units of average consumption. This normalization simplifies notation without changing qualitative results.

The first term captures payments under the respective contract, the second term captures cash flows from hourly net spot-market interactions, and the third term represents adjustment costs from shifting production away from the baseline level. The adjustment costs $h(q_{yt})$ reflect technological and organizational frictions in flexible operation and are given by

$$h(q_{yt}) = \gamma_1 |\bar{q} - q_{yt}|^{\gamma_2}, \quad (5)$$

where the parameter $\gamma_1 > 0$ scales the cost of adjustment, while $\gamma_2 > 1$ governs its curvature.

Integrating operating costs over all periods within a year subject to two operational constraints yields annual operating costs OC_y^c :

$$\begin{aligned} \min_{\{q_{yt}\}_{t \in [0, T]}} \quad & OC_y^c = \int_0^T OC_{yt}^c dt \\ \text{s.t.} \quad & q_{yt} \in [\bar{q} - F, \bar{q} + F] \quad \forall t \in [0, T], \\ & \int_0^T q_{yt} dt = T\bar{q}. \end{aligned} \quad (6)$$

The first constraint describes the flexibility bounds within which the firm can shift consumption around the baseline level. It implies that the ability to shift consumption across time is limited by the installed flexibility capacity F . The second constraint describes the fixed annual production target, defined in terms of the firm's total annual electricity demand. It ensures that flexibility is used for load shifting rather than for changing total output. The solution to (6) yields the minimized operating costs $OC_y^c(F)$ for a given year y and procurement option c , the distribution of which enters the investment problem in the first stage.

5 Analytical Results

The analytical results are derived recursively. We first characterize the optimal intra-annual consumption schedule in $s = 2$ for each contract type c and under a given flexibility investment F . We then turn to the investment decision in $s = 1$, taking the optimal consumption schedule into account. For the analytical benchmark, we assume quadratic adjustment costs with $\gamma_1 > 0$ and $\gamma_2 = 2$ (Equation 5).⁵ Furthermore, under both the baseload and REP hedge, expected contracted electricity equals average electricity consumption ($\mathbb{E}[q_{yt}^{rep}] = q^{bl} = \bar{q}$).

5.1 Production stage

Optimal consumption schedule. In the production stage $s = 2$, the firm optimizes its intra-annual electricity consumption $\{q_{yt}\}_{t \in [0, T]}$ as the solution to (6). Because contracted electricity and resulting payments are independent of the realized consumption schedule, contract choice does not affect the marginal incentive to shift consumption but only operating-cost levels. The consumption schedule is thus governed by spot-market prices and adjustment costs.

⁵Convexity can alternatively be introduced through increasing marginal investment costs. Consistent with industrial investments in flexibility (Klaucke et al., 2026), we maintain linear investment costs and quadratic adjustment costs.

The formal derivation of the optimal consumption schedule is derived in Appendix B.2. Within a year, when spot prices are high, the firm reduces electricity consumption within its installed flexibility bounds and can sell contracted electricity to the spot market. Conversely, when prices are low, the firm increases consumption and purchases additional electricity from spot markets. Flexibility therefore creates an opportunity for intra-annual arbitrage across periods with different electricity prices.

Exemplary optimal consumption schedules are illustrated in Figure 4b, distinguishing between two cases. In years with high pre-determined flexibility capacity relative to price variability ($2\gamma_1 F > \beta\theta_y$), the firm's consumption schedule is not constrained by its flexibility capacity and

$$q_{yt}^u = \bar{q} - \frac{\beta\theta_y}{2\gamma_1} \left(1 - \frac{2t}{T}\right). \quad (7)$$

In years when price variability is high compared to flexibility capacity ($2\gamma_1 F \leq \beta\theta_y$), the consumption schedule is constrained in periods of very high and low electricity prices, yielding a piecewise consumption schedule with the switching points t_1 and t_2 :

$$q_{yt}^c = \begin{cases} q^{\min}, & t \in [0, t_1), \\ \bar{q} - \frac{\beta\theta_y}{2\gamma_1} \left(1 - \frac{2t}{T}\right), & t \in [t_1, t_2], \\ q^{\max}, & t \in (t_2, T]. \end{cases} \quad (8)$$

The regime switch from an unconstrained to a constrained consumption schedule can be defined by a cutoff value of the variability shock $\theta_F(F) := \frac{2\gamma_1 F}{\beta}$. For small (large) variability realizations $\theta_y < \theta_F(F)$ ($\theta_y \geq \theta_F(F)$), the consumption schedule is unconstrained (constrained).⁶

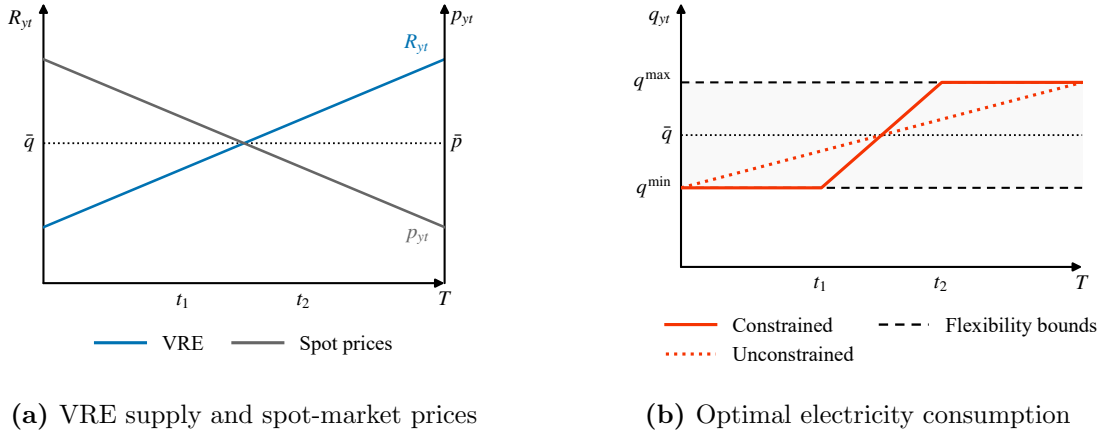


Figure 4: Optimal consumption schedule

Note: Panel (a) depicts VRE generation and electricity spot-market prices within an exemplary year. Panel (b) depicts the corresponding optimal consumption schedule. Flexibility allows the firm to operate between $q^{\max} = \bar{q} + F$ and $q^{\min} = \bar{q} - F$.

⁶In the following analyses, we assume that at least one year follows a constrained consumption schedule. Thus, we optimize over either an entirely constrained set of years or a mix of constrained and unconstrained regimes.

Annual operating costs. Using Equation (4) and integrating over the optimal consumption schedule yields annual operating costs by contract type:

$$OC_y^{bl}(F, \theta_y) = T \left[p^{bl} \bar{q} + G(F, \theta_y) \right], \quad (9)$$

$$OC_y^{rep}(F, \theta_y) = T \left[p^{rep} \bar{q} + \frac{\beta \theta_y^2}{3} + G(F, \theta_y) \right], \quad (10)$$

with

$$G(F, \theta_y) = \begin{cases} -\frac{\beta^2 \theta_y^2}{12 \gamma_1}, & \theta_y < \theta_F(F), \\ -\frac{\beta \theta_y F}{2} + \gamma_1 F^2 - \frac{2 \gamma_1^2 F^3}{3 \beta \theta_y}, & \theta_y \geq \theta_F(F). \end{cases} \quad (11)$$

The first term of (9) and (10) captures contract-specific payments for the contracted supply. The last term, $G(F, \theta_y)$, captures piecewise flexibility-related operating cost components that are common across contract types. Unique to the REP hedge is the middle term $\frac{\beta \theta_y^2}{3}$. It captures the firm's adverse exposure to profile effects of the REP hedge. It is cost-increasing because the REP hedge delivers relatively more electricity when prices are low and vice versa.

5.1.1 Comparative statics

Two properties of annual operating costs are central for the investment decision, which we identify by analyzing the comparative statics.

Flexibility capacity (F). Flexibility increases the firm's ability to arbitrage intra-annual price fluctuations, thereby reducing operating costs. At the same time, larger production adjustments require greater deviations from the baseline production schedule and thus incur increasing adjustment costs. The marginal effect of additional flexibility capacity on operating costs is identical for both contract types, given by

$$m(F, \theta_y) := \frac{\partial OC_y^c(F, \theta_y)}{\partial F} = \begin{cases} 0, & \theta_y < \theta_F(F), \\ -\frac{T}{2 \beta \theta_y} (\beta \theta_y - 2 \gamma_1 F)^2 \leq 0, & \theta_y \geq \theta_F(F). \end{cases} \quad (12)$$

In years with an unconstrained consumption schedule ($\theta_y < \theta_F(F)$), an additional unit of flexibility capacity has no operating value. Arbitrage opportunities are small compared to adjustment costs and the installed flexibility is sufficient to operate the optimal consumption schedule. By contrast, in flexibility-constrained states ($\theta_y \geq \theta_F(F)$), additional capacity reduces operating costs. The cost reduction from additional load shifting across time periods is larger than the incurred adjustment costs.

VRE and price variability (θ_y). The volatility shock θ_y affects operating costs through two channels. First, an increase in θ_y raises spot price dispersion and thereby strengthens opportunities for intra-annual arbitrage. This arbitrage channel is present under all contract

types and lowers operating costs. Second, under the REP contract, higher renewable variability also creates a wedge between contracted renewable generation q_{yt}^{rep} and electricity demand q_{yt} . This exposure effect is unique to the REP contract and increases operating costs whenever surplus electricity must be sold at low prices or additional electricity must be purchased at high prices. Thus, while the marginal operating value of flexibility is identical for the REP and baseload contracts, the effect of increasing variability on operating costs differs.

For the baseload hedged firm,

$$\frac{\partial OC_y^{bl}(F, \theta_y)}{\partial \theta_y} = \begin{cases} -\frac{T\beta^2\theta_y}{6\gamma_1}, & \theta_y < \theta_F(F), \\ T \left[-\frac{\beta F}{2} + \frac{2\gamma_1^2 F^3}{3\beta\theta_y^2} \right], & \theta_y \geq \theta_F(F). \end{cases} \quad (13)$$

Thus, operating costs under the baseload hedge decrease monotonically in θ_y . High-variability across years offers greater opportunities for profitable load shifting.

For the REP hedge, the additional exposure term $\beta\theta_y^2/3$ changes the effect of variability:

$$\frac{\partial OC_y^{rep}(F, \theta_y)}{\partial \theta_y} = \begin{cases} -\frac{T\beta^2\theta_y}{6\gamma_1} + \frac{2T\beta\theta_y}{3} = \frac{T\beta\theta_y}{6\gamma_1} (4\gamma_1 - \beta), & \theta_y < \theta_F(F), \\ T \left[-\frac{\beta F}{2} + \frac{2\gamma_1^2 F^3}{3\beta\theta_y^2} + \frac{2\beta\theta_y}{3} \right], & \theta_y \geq \theta_F(F). \end{cases} \quad (14)$$

Hence, the effect of the volatility shock on REP operating costs depends on the interplay between the arbitrage and the exposure effect. Under the sufficient condition $\beta < 4\gamma_1$, additional variability increases REP operating costs. Then, operating costs under the two hedges are differentially affected by increasing variability:

$$\frac{\partial OC_y^{bl}}{\partial \theta_y} < 0, \quad \frac{\partial OC_y^{rep}}{\partial \theta_y} \begin{cases} > 0, & \beta < 4\gamma_1, \\ \geq, & \beta \geq 4\gamma_1. \end{cases} \quad (15)$$

The differential effect of variability on operating costs for the REP and baseload hedge is essential to derive the CVaR and thus risk-averse optimal investment levels. For the baseload firm, the most expensive years are always those with low VRE and price variability. For the REP firm, the effect depends on the interplay of the arbitrage and the exposure effect. This effect is also visualized in Figure 5. While baseload operating costs are strictly decreasing in θ_y , the REP operating costs are convex in θ_y , with the exact shape depending on parametrization and flexibility capacity.

Cross-derivatives. Taking the cross-derivatives yields

$$\frac{\partial^2 OC_y^c}{\partial \theta_y \partial F} \leq 0. \quad (16)$$

Hence, additional flexibility has no marginal value in low-volatility states but becomes increasingly valuable once flexibility binds in high-volatility states.

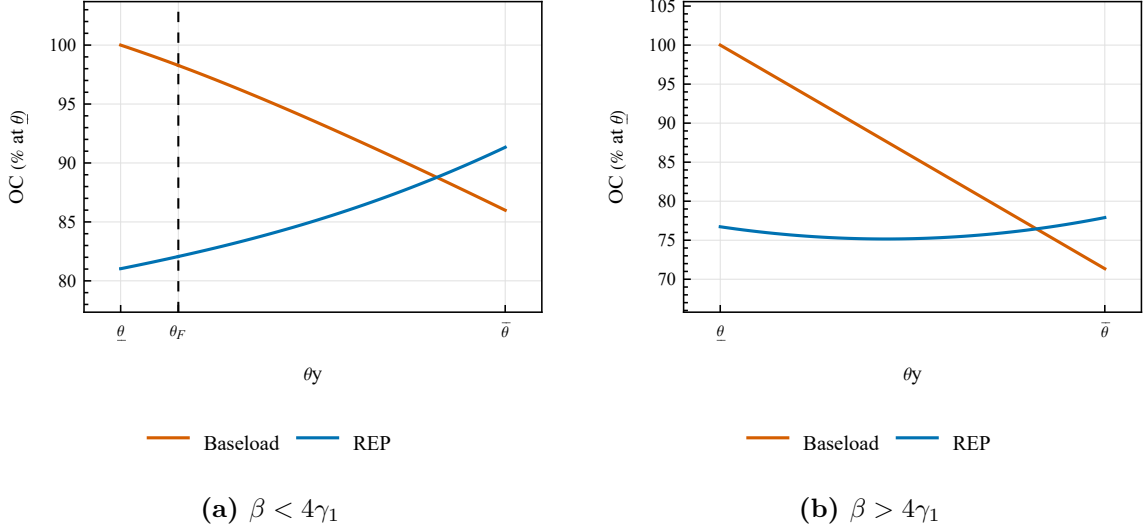


Figure 5: Annual operating costs across volatility states

Note: Panel (a) shows the case in which the sufficient condition $\beta < 4\gamma_1$ holds. The regime switch occurs at $\theta_F(F)$: for smaller θ_y realizations, the unconstrained consumption schedule is implemented; for larger realizations, the constrained schedule is implemented. Panel (b) shows a case in which $\beta > 4\gamma_1$. Operating costs decrease in θ_y under the baseload hedge, while the shape of REP operating costs depends on the relative strength of the arbitrage and exposure effects. Operating costs are normalized by baseload operating costs at $\underline{\theta}$.

5.2 Investment stage

We now turn to the preceding investment stage $s = 1$. At this stage, the firm knows the distribution of the volatility shock θ_y and chooses flexibility capacity taking the consumption schedule into account, optimizing (3).⁷ We first consider a risk-neutral firm and then introduce risk-averse decision making, focusing on the intuition of the results that explains the mechanism. Additional derivations and a graphical summary are presented in Appendix B.4.

5.2.1 Risk-neutral investment

Under risk neutrality ($\omega = 0$), the firm minimizes expected total costs,

$$\min_{F \geq 0} TC_{RN}^c(F) = IC(F) + \mathbb{E}_y[OC_y^c(F)] = \lambda F + \frac{1}{\bar{\theta} - \underline{\theta}} \int_{\underline{\theta}}^{\bar{\theta}} OC_y^c d\theta_y. \quad (17)$$

Using the previously derived marginal operating-cost effect $m(F, \theta_y)$ (12), we can define the expected marginal operating-cost effect relevant in the first-order condition for optimal risk-neutral investment:

$$M(F) := \frac{\partial \mathbb{E}[OC_y^c(F)]}{\partial F} = \frac{1}{\bar{\theta} - \underline{\theta}} \int_{\underline{\theta}}^{\bar{\theta}} m(F, \theta_y) d\theta_y. \quad (18)$$

Because $m(F, \theta_y)$ is identical across contract types, $M(F)$ is also contract independent. Contract design affects expected operating-cost levels, but not the expected marginal return to flexibility. Consequently, an interior optimum as a solution to (17) satisfies $\lambda + M(F_{RN}) = 0$,

⁷To constrain the set of solutions, we make the feasible ex-ante assumption that the firm never invests so much that it is in an unconstrained consumption schedule in all variability realizations ($\theta_F(F) < \bar{\theta}$).

and thus:

$$F_{RN}^{bl} = F_{RN}^{rep} \equiv F_{RN}.$$

Intuitively, the contracts generate different operating-cost levels, but additional flexibility changes operating costs by the same amount for a given θ_y . Since under risk neutrality both firms average these marginal effects over the same distribution of θ_y , they face the same expected marginal return to flexibility. Given identical investment costs, they therefore choose the same level of flexibility.

5.3 The risk-averse firm

We now consider firms that minimize risk-adjusted total costs using the CVaR objective ($\omega > 0$):

$$\min_{F \geq 0} TC_{RA}^c(F) = \lambda F + (1 - \omega)\mathbb{E}[OC_y^c(F)] + \omega \text{CVaR}_\alpha^c(F). \quad (19)$$

In contrast to the risk-neutral case, investment decisions are no longer based solely on expected operating costs. Under the CVaR criterion, the worst $(1 - \alpha) \cdot 100\%$ realizations of annual operating costs receive additional weight. Consequently, the effect of risk aversion depends on the marginal operating value of flexibility in these highest-cost years. Since the marginal operating-cost effect $m(F, \theta_y)$ is identical across contracts but becomes weakly more negative as θ_y increases, contract design affects risk-averse investment through the volatility states that enter the CVaR.

More generally, the marginal effect of flexibility on the CVaR is given by

$$\frac{\partial \text{CVaR}_\alpha^c(F)}{\partial F} = \frac{1}{(1 - \alpha)(\bar{\theta} - \underline{\theta})} \int_{S_\alpha^c(F)} m(F, \theta_y) d\theta_y \quad (20)$$

where $S_\alpha^c(F)$ denotes the set of volatility realizations constituting the worst $(1 - \alpha) \cdot 100\%$ of annual operating costs. Hence, risk aversion increases investment if the CVaR places additional weight on states in which flexibility has a larger-than-average marginal operating value, and decreases investment if it places additional weight on states in which flexibility is less valuable.

Baseload hedge. For baseload firms, the most expensive years are those with low-volatility realizations. Relative to a risk-neutral firm, the CVaR objective therefore places greater weight on θ_y -realizations in which spot-market arbitrage opportunities are limited. Since flexibility has a lower marginal operating value in these states than in the average year,

$$\frac{\partial \text{CVaR}_\alpha^{bl}}{\partial F} \geq M(F), \quad (21)$$

where both terms are non-positive. Evaluated at the risk-neutral optimum, this makes the marginal risk-adjusted cost of additional flexibility weakly positive. Given convex total costs, risk aversion therefore reduces baseload investment relative to the risk-neutral benchmark:

$$F_{RA}^{bl} < F_{RN}.$$

REP hedge. The implications are fundamentally different under the REP hedge. Higher volatility simultaneously increases spot-market arbitrage opportunities and exposure to the renewable profile. The location of the REP downside-risk-states therefore depends on the relative importance of the arbitrage effect (AE) and the exposure effect (EE). These depend on the firm's flexibility level and thus on the investment cost parameter λ .

1) High investment cost ($\lambda \geq \lambda_{EE}$): For sufficiently high investment costs, firms invest in relatively little flexibility. Thus, high-volatility realizations generate the largest operating costs because limited flexibility capacity leaves the firm exposed to profile risk: excess supply must be sold at low market prices, while supply shortfalls require purchases at high spot-market prices. The CVaR places greater weight exclusively on high-volatility states, in which additional flexibility has large marginal operating value. Flexibility therefore acts as insurance against profile risk, implying that risk aversion increases flexibility investment relative to the risk-neutral benchmark:

$$F_{RA}^{rep} [\lambda \geq \lambda_{EE}] > F_{RN}.$$

2) Low investment cost ($\lambda \leq \lambda_{AE}$): For sufficiently low investment costs, firms install substantial flexibility capacity. Profile risk is then largely mitigated and downside risk becomes concentrated in low-volatility realizations in which spot-market arbitrage opportunities are limited. As under the baseload hedge, the CVaR places additional weight exclusively on states in which flexibility has a relatively low marginal operating value. Risk aversion therefore reduces flexibility investment:

$$F_{RA}^{rep} [\lambda \leq \lambda_{AE}] = F_{RA}^{bl} < F_{RN}.$$

For intermediate investment costs, both low- and high-volatility realizations may enter the REP downside-risk set, and the investment response depends on their relative contribution to the marginal CVaR effect. The exact threshold conditions are derived in Appendix B.4.

The central implication is that REP procurement fundamentally alters the relationship between risk aversion and flexibility investment. Unlike baseload hedging, which unambiguously reduces flexibility investment under risk aversion, REP procurement may increase investment because flexibility simultaneously generates arbitrage revenues and provides insurance against profile risk. Thus, under risk aversion, REP investment is always weakly higher than baseload investment:

$$\boxed{F_{RA}^{rep} \geq F_{RA}^{bl}}$$

The following numerical simulation maps this threshold logic to a calibrated industrial setting and examines whether the arbitrage or exposure effect dominates under realistic hourly price and renewable-generation profiles.

6 Numerical Application to the Pulp and Paper Industry

We use a stylized case study of the pulp and paper industry (PPI) to provide a more concrete setting for our analysis. Specifically, we simulate flexibility investments of a pulp and paper producer in a future German electricity market in 2030. This allows us to illustrate potential

implications of a REP hedge on industrial consumers and to expand our analytical results. As in the analytical model, we continue to model flexibility as the potential to shift load around a baseline consumption level with marginally increasing adjustment costs. Flexibility potential stems from operating on-site pulp storage. In contrast to the analytical model, we allow for a more realistic relationship between renewable energy generation and electricity prices, using simulated data based on [Klaucke et al. \(2026\)](#).

6.1 Demand-side flexibility in the pulp and paper industry

The PPI is an energy-intensive industry, accounting for 8.8% of European industrial electricity consumption in 2023 ([CEPI, 2024](#)). This size, coupled with its process structure, offers large potential for demand flexibility ([Paulus and Borggreffe, 2011](#)). Paper can either be produced from recycled paper or from wood as a raw material. We focus on the primary route, which follows three steps ([Ferreira De Almeida et al., 2026](#)): First, pulp making debarks the wood and then removes the fibers through chemical or mechanical pulping. In a second step, the fibers are bleached. Finally, it is pressed and dried in the third paper-making step.

The largest potential for flexible operation of the process lies in the mechanical pulping, which is responsible for up to 70% of a mill’s energy consumption ([Herre et al., 2020](#)). While the refiners used in this step are interruptible, the subsequent paper-making needs to run continuously. Thus, additional storage for pulp, which is flexibly filled but continuously emptied, is needed to enable flexible operation ([Kopernikus SynErgie, 2025](#)). This intermediate storage requires up-front investments ([Paulus and Borggreffe, 2011](#)).

Previous research has estimated significant savings potential for the PPI through flexible operation. [Herre et al. \(2020\)](#) identify electricity cost savings of 7.4% in summer and 2.3% in winter for a paper mill optimizing its bidding in day-ahead and reserve markets in Sweden. [Adetunji et al. \(2025\)](#) find cost reductions of up to 6% for the Finnish PPI optimizing its load curve.

6.2 Parametrization

We model the mechanical pulping of the paper production process and assume that it has a base electricity demand of 100 MW.⁸ Our parametrization is mostly based on the techno-economic assumptions in [Klaucke et al. \(2026\)](#), summarized in Table 1. For flexibility investments in the paper production process, they assume linear investment costs of 5240 €/MW for installing flexibility capacity. Furthermore, they assume variable costs of deviating from the baseload production level. While they do not specify a continuous adjustment cost function, they state that deviations of up to 20% from the baseload production level can be achieved at a lower variable cost of 10 €/MW, while larger deviations are more costly. We translate this into a quadratic adjustment cost function, varying its curvature in a sensitivity analysis (Section 6.5). As in the analytical model, we identify optimal flexibility investment for both the risk-neutral and the risk-averse firm. Our benchmark simulation assumes $\omega = 0.5$ and $\alpha = 0.9$ and we later perform a sensitivity analysis (Section 6.5).

⁸While this represents a large paper mill, it is not unusual for a production line to consist of three refiners with up to 30 MW production capacity each ([Helin et al., 2017](#)).

Klaucke et al. (2026) further simulate the German electricity market in 2030 with 80 % generation from renewable energy in a market with a strategic reserve. For seven weather years (2008 to 2014), they estimate hourly renewable generation and electricity prices. We use these seven years to derive a multinomial joint distribution of intra-annual renewable generation and electricity prices, as well as a Dirichlet distribution for inter-annual realizations. We then draw $Y = 1000$ synthetic years of $T = 8760$ hours as the basis of our simulation (see Appendix C.1 for details).

In line with the analytical model, the firm procures electricity with either the REP or baseload hedge. Both hedges are fairly priced: the baseload price corresponds to the average electricity price, whereas the REP is priced at the average market value of VRE generation (Section 6.4 provides an extension, where we vary this pricing assumption).⁹ We also consider spot procurement as a third option, in which all electricity is directly procured on the spot market without hedging. Such a firm is thus fully exposed to price risks. In Section 6.4, we allow for mixed hedging positions of the firm.

Table 1: Benchmark parametrization for the numerical simulation

Parameter	Time horizon		Hedge prices		Firm characteristics					
	Y	T	p^{bl}	p^{rep}	$\bar{q}$	λ	γ_1	γ_2	ω	α
Value	1000	8760 h	70.18 $\frac{\text{€}}{\text{MWh}}$	50.85 $\frac{\text{€}}{\text{MWh}}$	100 MW	5240 $\frac{\text{€}}{\text{MW}}$	10 $\frac{\text{€}}{\text{MW}}$	2	0.5	0.9

6.3 Benchmark simulation results

6.3.1 Production stage

The results of the intra-annual optimal production strategy confirm the results of the analytical model: Electricity consumption, and thus utilization of load shifting in each hour is equal across contract types, as well as for the spot-procuring firm. All three firms consume up to the bounds of their pre-determined flexibility capacity for high prices. Due to the increasing adjustment costs and prices bounded below by zero, the revenue potential of shifting load at low and moderate prices is limited. Thus, upward load shifting never extends up to the invested flexibility potential (see Appendix C.2 for more detail).

6.3.2 Investment stage

For risk-neutral firms, contract design does not affect optimal flexibility investment (Figure 6a). Once risk aversion is considered, investment decisions differ across contract types. Under the baseload hedge, the firm reduces its optimal investment level (Figure 6b). By contrast, firms under the REP hedge and spot procurement increase their flexibility investment in response to the exposure to profile risk.

Risk-neutral investment and operating costs. Risk-neutral investment levels (17 MW) and expected total costs (60.8 mio €) are equal across contract types. However, this hides considerable inter-annual heterogeneity in operating costs (see Table 2 and Appendix C.3).

⁹In the benchmark calibration, the REP price is therefore 27.6% below the baseload price.

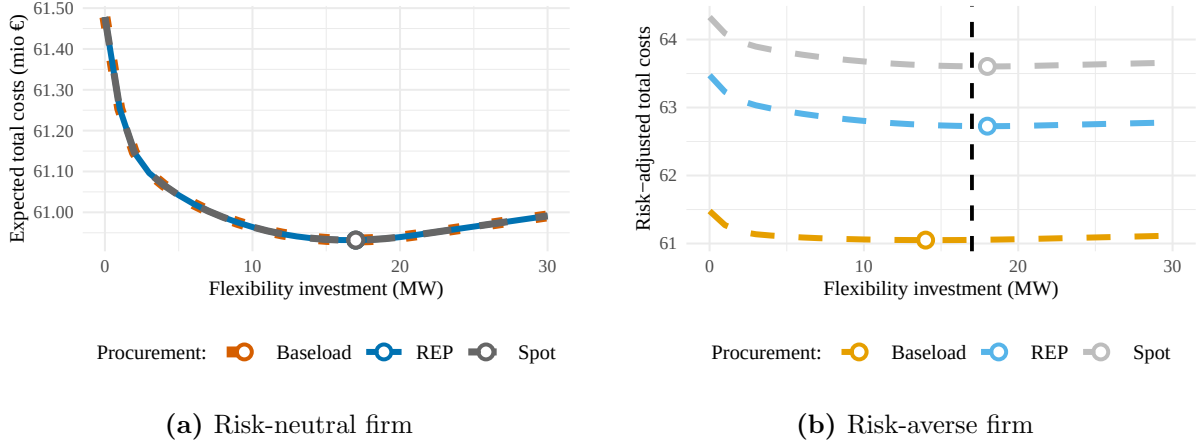


Figure 6: Total costs and optimal flexibility investment

With neither price nor volume risk, operating costs with the baseload contract are stable across years (standard deviation of 0.20 mio €). The firm is protected from downside risks, with only a slight chance to realize upside risks. A firm procuring electricity exclusively on spot markets has much higher volatility of annual operating costs (standard deviation of 2.74 mio €), being fully exposed to price risk. Compared to spot procurement, the REP hedge reduces the volatility of annual operating costs (standard deviation of 1.77 mio €).

Table 2: Standard deviation of annual operating costs

Baseload hedge	REP hedge	Spot procurement
0.20 mio €	1.77 mio €	2.74 mio €

CVaR and risk-averse investment. Risk aversion changes optimal flexibility investment across procurement types. Relative to the risk-neutral benchmark of 17 MW, the baseload firm’s optimal investment decreases by 18% (to 14 MW), whereas the REP-hedged and spot firms increase investment by 6% (to 18 MW).

Figure 7 helps explain this pattern by showing the characteristics of the high-cost years that enter the CVaR. For the baseload-hedged firm, the most expensive years are characterized by low price variability. As shown in the analytical model, the arbitrage value of flexibility is limited in such years, making them high-cost states.

For the REP-hedged firm, the opposite holds. Its most expensive years are characterized by high price variability. In these states, mismatches between the renewable delivery profile and the firm’s consumption profile are settled at more extreme prices and therefore become more costly. Flexibility provides an insurance value by reducing market exposure and helping the firm manage renewable profile risk. In the benchmark simulation, this exposure effect dominates the uncertain arbitrage effect, inducing the risk-averse REP firm to invest more in flexibility. Importantly, profile exposure alone does not drive high-cost outcomes; it materializes when the associated imbalances are settled under volatile prices.

The spot-exposed firm directly bears price risk. Consequently, its CVaR tail is primarily dominated by years with high mean electricity prices. Because renewable generation and elec-

tricity prices are negatively correlated, these years also tend to exhibit low average renewable generation. Price variability also increases costs, but it appears less distinctive than the shift in mean prices.

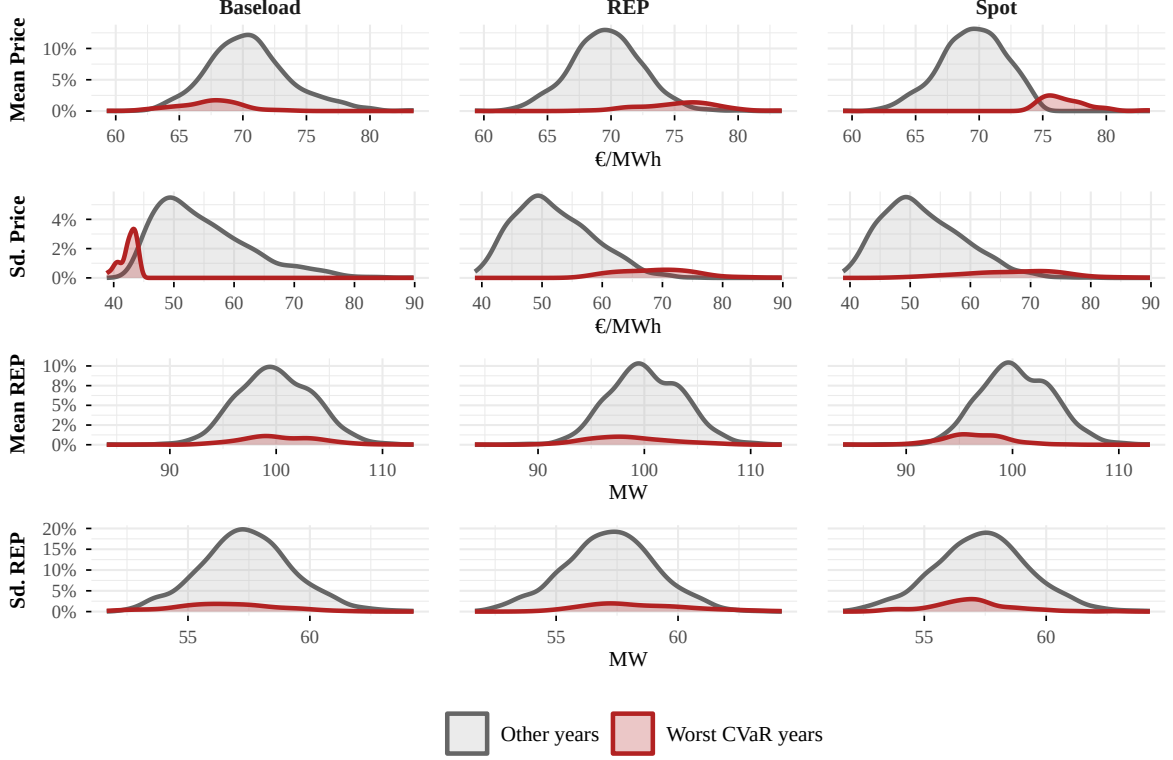


Figure 7: Density of the 10% most expensive CVaR years compared to the other 90% of years

Investment cost level. Analytically, we identified threshold levels (λ_{AE} , λ_{EE} , see Section 5.3) in terms of investment costs, which are decisive for the relative investment level between the different contracts. Numerically, we can uncover whether the arbitrage or the exposure effect is dominating. Plotting risk-averse optimal investment for the different contract types in Figure 8, we see that for all levels of investment costs, the exposure effect is dominating for REP firms. Thus, optimal risk-averse flexibility investment increases relative to investments under the baseload contract. The REP hedge therefore always leads to increased flexibility investment relative to the baseload hedge ($\lambda \geq \lambda_{EE}$).

6.4 Model extensions

Hedge pricing. The total cost level of the paper plant depends on our assumptions about the prices of the different hedges. In our benchmark specification, we assume actuarially fair, risk-neutral pricing. However, the internalization of the profile risk of VRE supply likely leads to price mark-ups on baseload hedges or discounts on REP hedges. This is in line with surveys of market participants on PPA pricing in Europe: price mark-ups on pay-as-consumed PPAs (baseload-similar contracts) relative to pay-as-produced PPAs (REP-similar contracts) are between 1.7 €/MWh and 6.5 €/MWh (BloombergNEF, 2022), representing an increase of up to

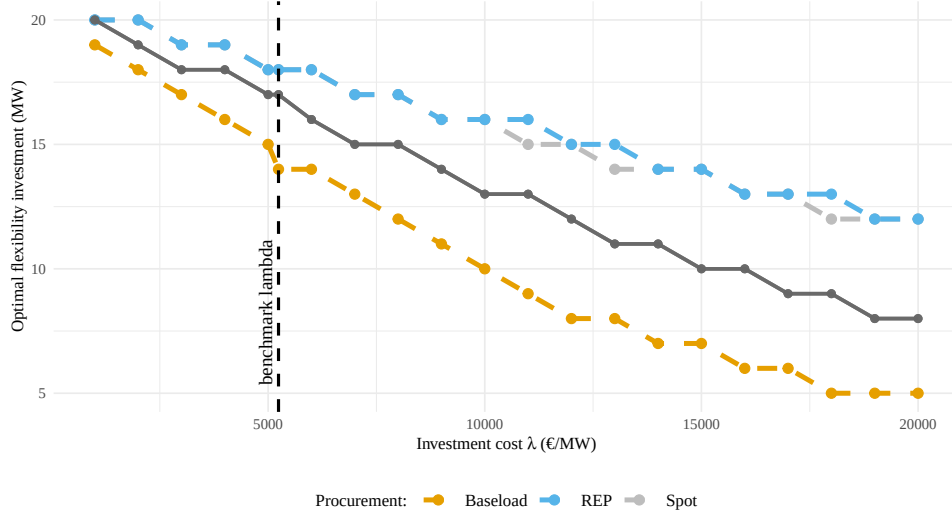


Figure 8: Optimal flexibility investment by investment cost parameter λ

Note: Dashed lines represent risk-averse investment. When the gray risk-averse spot investment is not visible, it is identical to turquoise risk-averse REP investment. The solid dark-gray line represents risk-neutral investment, which is identical across procurement types.

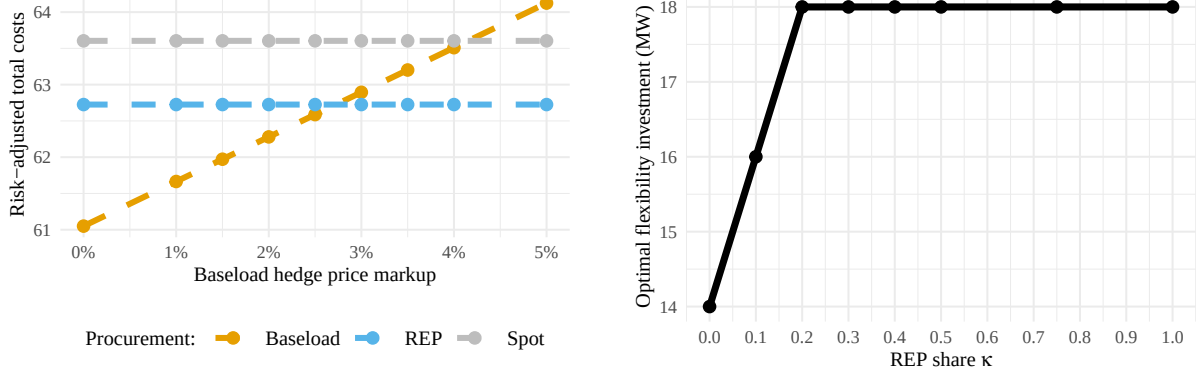
10%. Considering that our analysis is simulated for the year 2030 with increased RE shares, these mark-ups might further rise.

Accounting for these profile risk premia on the baseload hedge, we introduce a price mark-up on the baseload hedge in Figure 9a. While the investment level in flexibility is unaffected by the hedge prices, the risk-adjusted total costs of the baseload-hedged firm linearly increase with the mark-up. At mark-ups between 2.5% and 3%, the risk-adjusted costs of the baseload firm equal those of the REP firm, and between 4% and 4.5% those of the spot firm. Deviating from our assumption of fair pricing thus can make the REP hedge competitive in terms of risk-adjusted total costs with the baseload hedge, at price mark-ups well in line with those observed in the European PPA market.

Portfolio hedging. In our benchmark model, we assume that each firm hedges its entire average annual electricity consumption through one hedge. However, in reality, firms employ more sophisticated hedging strategies combining different products (Arellano and Carrión, 2023). We test one such portfolio approach with a mixed hedge that covers κ of expected electricity consumption via a REP hedge and the remaining $(1 - \kappa)$ via the baseload hedge. Figure 9b reveals that under benchmark model assumptions, the optimal investment in flexibility increases already at small REP shares in the hedge portfolio. When 20% of annual electricity is covered with the REP hedge, the optimal investment level of a fully REP-hedged firm is reached. This indicates that already at small REP share levels, the firm is exposed to profile risk that increases the insurance value of flexibility.

6.5 Sensitivity analysis

Risk aversion. Our results show that the incentive effects of different hedging contracts are highly dependent on the level of risk aversion of industrial firms when making investments in



(a) Risk-adjusted total costs under optimal investment with price mark-up on p^{bl}

(b) Optimal investment under portfolio hedge of $\kappa \cdot \text{REP}$ and $(1 - \kappa) \cdot \text{baseload}$

Figure 9: Extensions: baseload price mark-ups and mixed hedge portfolio

flexibility capacity. Figure 10 thus plots the sensitivity of optimal investment to the two risk aversion parameters, the CVaR weight ω and the share $(1 - \alpha) \cdot 100\%$ of most expensive years considered in the CVaR.

For the baseload contract higher risk aversion decreases the optimal flexibility investment, as a higher return for the investment under uncertainty is required. For the REP firm, increasing the level of risk aversion increases optimal flexibility investment. The insurance value of additional investment as a physical hedge increases. Already at moderate levels of risk aversion (e.g. $\omega > 0.15$ and $\alpha > 0.1$), the REP hedge leads to more flexibility investment compared to the baseload hedge.

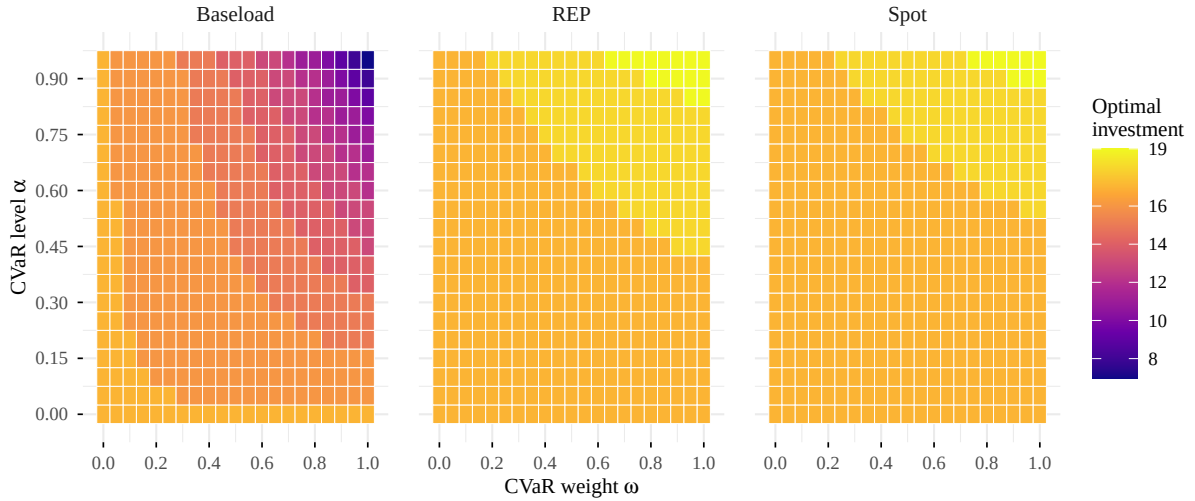


Figure 10: Optimal flexibility investment under alternative risk aversion parameters

Note: Risk aversion increases when moving farther away from the origin.

Adjustment costs. The results and the mechanism are also robust to changes in the adjustment cost function of the firm. In Appendix C.4, we show that when varying the parameters γ_1 and γ_2 in the adjustment cost function, the results of increased relative investment of the risk-averse REP firm compared to the baseload firm is robust.

7 Policy Implications and Conclusion

This paper investigates how the design of long-term electricity hedges affects industrial investment in load-shifting capacity under risk aversion. We formalize the operational and investment incentives of firms given two different contracts. Under the baseload hedge, flexibility creates value mainly through arbitrage between high- and low-price periods. Under the REP hedge, flexibility additionally serves as a physical hedge against renewable profile risk. We illustrate this in a numerical application, calibrated to the pulp and paper industry. The simulation highlights that under risk aversion, the exposure effect outweighs the arbitrage effect. Therefore, under risk aversion, the REP-hedged firm invests more in flexibility than its risk-neutral counterpart and the risk-averse baseload-hedged firm. The REP hedge becomes particularly attractive once profile-risk premia are reflected in baseload contract prices. In our simulation, a baseload mark-up between 2.5% and 3% is sufficient for the risk-adjusted total costs of the baseload-hedged firm to exceed those of the REP-hedged firm. Thus, the REP hedge can reduce risk-adjusted total costs for flexible firms when the alternative is an increasingly expensive baseload product.

These findings have direct policy implications. First, contract design matters. Long-term contract design should be seen as one channel through which policymakers can influence the emerging flexibility gap in electricity systems. As renewable shares increase, additional flexibility is needed to balance periods of high renewable generation and scarcity hours. This flexibility can be provided either by supply-side options, such as dispatchable backup capacity, or by demand-side flexibility from consumers that adjust their load to the renewable generation profile (Papaefthymiou et al., 2018). Our results show that hedging design can affect incentives for industrial demand-side flexibility, contributing to closing the flexibility gap. This has direct implications for current debates on industrial electricity prices. Policy proposals often focus on protecting industrial consumers from high and volatile electricity prices, but our results suggest that the profile of this protection matters. Baseload-like support, such as the German *Industriestrompreis* (European Commission, 2026a), can stabilize costs, but at the same time reduce consumers' exposure to the time-varying value of electricity and thereby weaken incentives for flexible and system-friendly consumption. Profile-based alternatives, such as tripartite energy agreements (Neuhoff et al., 2025; European Commission, 2026b), could limit operating cost volatility while maintaining consumers' exposure to profile risk that incentivizes investment in flexibility.

Second, policymakers should account for risk aversion when evaluating flexibility incentives of different policies. Flexibility investment is often not part of the core business of industrial firms and requires irreversible up-front expenditures. Firms therefore evaluate uncertain flexibility revenues more cautiously than a risk-neutral benchmark would imply. Financing constraints can further amplify this effect if lenders and investors are themselves risk-averse. Ignoring risk aversion therefore leads to an overestimation of flexibility investment for baseload-hedged firms and an underestimation for REP-hedged firms.

Third, firms without technical flexibility potential may prefer to contract additional flexibility services instead of investing in load-shifting capacity themselves. This points to a potential role for intermediaries, such as retailers or aggregators, and “flexibility-as-a-service” business

models. Such actors could help firms manage residual profile risk or offer financial products that complement REP-style procurement.¹⁰

Our analysis has limitations that point to opportunities for future research. First, the model only provides a stylized representation of both the industrial production process and the electricity market. Firms interact only with the spot market and do not participate in balancing, reserve, or congestion-management markets. However, these markets could affect the investment decision via additional revenue streams for flexibility, but also via transaction costs and regulatory constraints.

Second, optimizing the production stage, we assume perfect foresight of intra-annual realizations of electricity prices and renewable generation. In practice, firms face substantial uncertainty regarding intra-annual realizations, limiting their ability to optimally schedule electricity consumption. This is likely to reduce the value of load shifting and thereby lower investment incentives. On the other hand, our model is agnostic to the considered time horizon. Instead of assuming perfect foresight over an annual horizon, the model could be equally applied to shorter operational horizons, such as days, where price forecasts are more reliable and the assumption of perfect foresight is thus easier to justify.

Third, we take electricity prices as given and abstract from general equilibrium effects of additional demand-side flexibility on market prices. If many firms invest in and use flexibility, price spreads likely decrease, reducing the profitability of additional flexibility investment (Ambrosius et al., 2018).

Finally, the numerical application should be interpreted as an illustrative example. The simulation is based on a restricted set of seven simulated weather years for a German electricity market in 2030, expanded by drawing further synthetic years from their distribution. The numerical results should therefore be interpreted as an illustration and consistency check of the analytical mechanism rather than as precise estimates of flexibility investment or cost savings.

¹⁰Such contracts are currently not available at a large scale, but could be catalyzed with a REP hedge and be important to stabilize the revenue of external flexibility providers, such as battery operators. In 2015, the European Energy Exchange briefly introduced a product called intraday cap-future, which allowed to hedge intraday price peaks (Hinderks and Wagner, 2019). However, due to limited price volatility resulting from over-capacities at the time, the product quickly faded (Connect Energy Economics, 2024).

Declaration of used generative AI and AI-assisted technologies

During the preparation of this work, the authors used ChatGPT (OpenAI) to assist with coding, check spelling and grammar, and make minor editorial improvements to the text. After using this tool, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

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A List of Variables and Parameters

Symbols	Description
<u>Indices and sets</u>	
$s \in \{0, 1, 2\}$	Model stage {contract environment, investment, production}
$t \in [0, T]$	Periods within one year of the production stage
$c \in \{bl, rep\}$	Contract type, either baseload or REP
y	Index of a representative year
<u>Decision variables</u>	
q_{yt}	Electricity consumption of the firm in period-t
F	Flexibility capacity for load shifting
<u>Stochastic variables</u>	
R_{yt}	Renewable energy generation in period-t
p_{yt}	Spot market electricity price in period-t
$\theta_{yt} \sim \mathcal{U}(-\theta_y, \theta_y)$	Intra-annual renewable variability shock
$\theta_y \sim \mathcal{U}(\underline{\theta}, \bar{\theta})$	Inter-annual variability, determining the dispersion of θ_{yt}
<u>Cost and risk measures</u>	
IC	Annualized investment cost, $IC = g(F)$
OC_y	Annual operating costs from electricity expenditure
TC	Total cost in a representative year
$CVaR_\alpha$	Conditional value at risk at confidence level α
<u>Parameters</u>	
β	Strength of the negative relationship between RE and prices
α	CVaR confidence level; the tail contains the worst $(1 - \alpha) \cdot 100\%$ outcomes
ω	Weight on $CVaR_\alpha$
λ	Investment cost per MW of flexibility capacity
γ_1 and γ_2	Adjustment cost function parameters (scale and curvature)
η	Share of renewable energy generation for REP hedge supply
κ	Share of REP hedge in portfolio of hedges
$\bar{q}$	Baseline electricity consumption
$\bar{R}$	Baseline renewable energy generation
$\bar{p}$	Baseline electricity price
p^{rep}	Unit cost of electricity under the REP hedge
p^{bl}	Unit cost electricity under the baseload hedge
<u>Functions</u>	
$g(F) = \lambda F$	Annualized flexibility investment costs
$h(q_{yt}) = \gamma_1(q_{yt} - \bar{q})^{\gamma_2}$	Adjustment costs for deviations from baseline consumption

B Analytical Model: Production Stage

B.1 Intra-annual realizations of volatility shocks

Our assumption of perfect foresight within the year allows us to order time periods to improve the solvability of the analytical model. Rather than following chronological time, hours are ordered according to their position in the price duration curve, ranging from the highest-price hour to the lowest-price hour. Under the assumption of a uniformly distributed intra-annual volatility shock, the corresponding functions are linear. Renewable generation and electricity prices can therefore be written as

$$\begin{aligned} R_{yt} &= \bar{R} - \theta_y + \frac{2\theta_y}{T}t \\ p_{yt} &= \bar{p} + \beta\theta_y - \frac{2\beta\theta_y}{T}t \end{aligned}$$

The parameter θ_y determines the magnitude of intra-annual variability in year y . Larger realizations of θ_y increase the spread between the lowest and highest renewable-output hours. It also increases the spread between the lowest and highest electricity price hours, scaled by the cannibalization parameter β . Consequently, higher values of θ_y correspond to years with more pronounced profile effects. Figure B.1 illustrates this relationship by comparing two realizations $\theta_2 > \theta_1$.

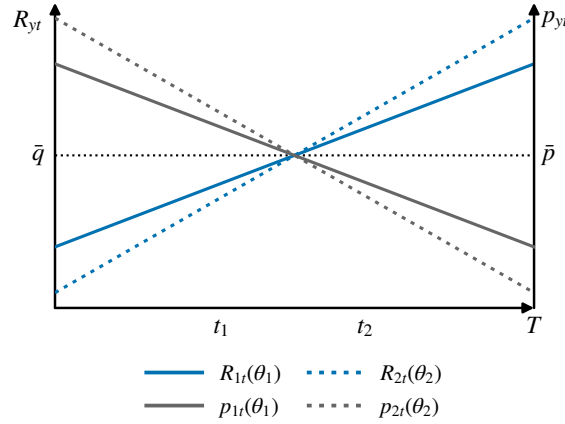


Figure B.1: Renewable generation and prices for two realizations of the volatility shock

B.2 Derivation of intra-annual production strategy

This section derives the firm's optimal intra-annual electricity-consumption schedule for a given flexibility capacity F and realization of the annual volatility shock θ_y . We assume quadratic adjustment costs, $\gamma_2 = 2$. Conditional on the realized spot-price path, the optimal production schedule is identical under the baseload and REP hedge.¹¹

¹¹For ease of notation, we use continuous-time notation and suppress the year index y .

Optimality conditions. From the optimization problem stated in (6), we set up the Lagrangian as

$$\mathcal{L} = \int_0^T \left[p^c q^c(t) + (q(t) - q^c(t))p(t) + \gamma_1 (q(t) - \bar{q})^2 + v(t)(q(t) - q^{\max}) + \nu(t)(q^{\min} - q(t)) \right] dt + \lambda_L \left[\int_0^T q(t) dt - T\bar{q} \right]. \quad (22)$$

The first-order condition is

$$p(t) + \lambda_L + 2\gamma_1 (q(t) - \bar{q}) + v(t) - \nu(t) = 0, \quad (23)$$

with complementary slackness

$$v(t)(q(t) - q^{\max}) = 0, \quad \nu(t)(q^{\min} - q(t)) = 0. \quad (24)$$

Whenever neither flexibility bound binds at $q^{\min} < q(t) < q^{\max}$, the respective multipliers become zero $v(t) = \nu(t) = 0$, and the unconstrained optimum is

$$q^u(t; \lambda_L) = \bar{q} - \frac{p(t) + \lambda_L}{2\gamma_1}. \quad (25)$$

The constrained optimal consumption schedule is then the unconstrained solution projected onto the feasible consumption interval:

$$q^*(t; \lambda_L) = \min \{ q^{\max}, \max \{ q^{\min}, q^u(t; \lambda_L) \} \}. \quad (26)$$

Determining the multiplier. From Appendix B.1, the ordered electricity price profile is

$$p(t) = \bar{p} + \beta\theta_y - \frac{2\beta\theta_y}{T}t, \quad (27)$$

or, expressed as a deviation from its average,

$$p(t) - \bar{p} = \beta\theta_y \left(1 - \frac{2t}{T} \right). \quad (28)$$

Hence, the price profile is symmetric around $\bar{p}$. Since adjustment costs and flexibility bounds are likewise symmetric around $\bar{q}$, the annual production requirement is satisfied when the reference price $-\lambda_L$ equals the average electricity price:

$$\lambda_L^* = -\bar{p}. \quad (29)$$

It follows that

$$q^u(t) = \bar{q} - \frac{\beta\theta_y}{2\gamma_1} \left(1 - \frac{2t}{T} \right). \quad (30)$$

The resulting schedule is symmetric around $\bar{q}$, implying

$$\int_0^T (q^*(t) - \bar{q}) dt = 0, \quad (31)$$

and hence $\int_0^T q^*(t) dt = T\bar{q}$, thus satisfying the annual consumption requirement.

Switching points and optimal schedule. Whether the flexibility bounds bind depends on the size of installed flexibility relative to the intra-annual price spread, determined by the annual volatility shock θ_y . The maximum absolute deviation of the unconstrained schedule from baseline is reached at either $t = 0$ or $t = T$, thus:

$$\max_{t \in [0, T]} |q^u(t) - \bar{q}| = \frac{\beta\theta_y}{2\gamma_1}. \quad (32)$$

Hence, two cases arise. First, if

$$F < \frac{\beta\theta_y}{2\gamma_1}, \quad (33)$$

the unconstrained schedule exceeds the flexibility bounds in the highest- and lowest-price periods. The switching points are obtained from $|q^u(t) - \bar{q}| = F$, yielding

$$t_1 = \frac{T}{2} - \frac{\gamma_1 FT}{\beta\theta_y}, \quad t_2 = \frac{T}{2} + \frac{\gamma_1 FT}{\beta\theta_y}. \quad (34)$$

The optimal consumption schedule then consists of three regions:

$$q^*(t) = \begin{cases} q^{\min}, & t \in [0, t_1), \\ \bar{q} - \frac{\beta\theta_y}{2\gamma_1} \left(1 - \frac{2t}{T}\right), & t \in [t_1, t_2], \\ q^{\max}, & t \in (t_2, T]. \end{cases} \quad (35)$$

Second, if

$$F \geq \frac{\beta\theta_y}{2\gamma_1}, \quad (36)$$

the consumption schedule remains within the installed flexibility bounds throughout the year. The optimal schedule is therefore unconstrained and given by

$$q^*(t) = q^u(t) = \bar{q} - \frac{\beta\theta_y}{2\gamma_1} \left(1 - \frac{2t}{T}\right), \quad t \in [0, T]. \quad (37)$$

Thus, whether installed flexibility is fully utilized depends on the realized annual volatility shock θ_y , the cannibalization parameter β , and the magnitude of adjustment costs γ_1 . In years with relatively large renewable variability, and thus high price variability through β , the unconstrained consumption deviations are larger and the flexibility bounds are more likely to bind. In low-volatility years, the same installed flexibility capacity may only be used partially. Higher adjustment costs also lead to lower utilization of flexibility and thus potentially to an unconstrained consumption schedule.

B.3 Annual operating costs

Effect of flexibility. A graphical representation of the marginal effect of flexibility capacity on operating costs is depicted in Figure B.2. For different levels of pre-determined flexibility capacity $F_1 < F_2$, the marginal effect is either zero or negative and decreasing. This depends on the location of the cutoff value $\theta_F(F) = \frac{2\gamma_1 F}{\beta}$, which determines whether in the respective year the firm has an unconstrained or constrained consumption schedule. If it is constrained, it is bounded by its flexibility capacity and additional flexibility capacity would reduce operating costs.

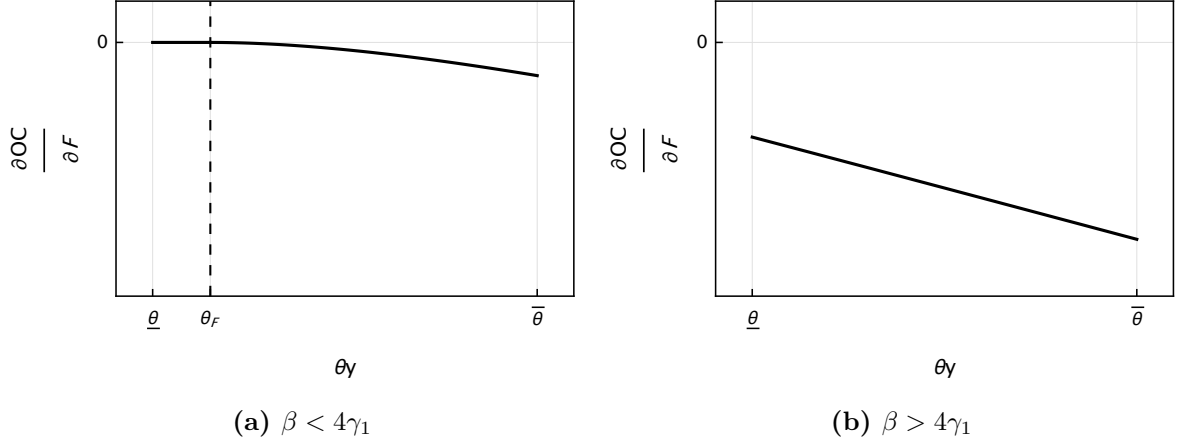


Figure B.2: Marginal operating value of flexibility

Note: In panel (a), the firm has a mix of unconstrained consumption when $\theta_y < \theta_F$ and constrained consumption when $\theta_y > \theta_F$. In panel (b), the firm has a constrained consumption schedule in any θ_y -realization. The underlying parametrization of the plots is equivalent to Plots 5a and 5b.

The second-order condition of deriving annual operating costs with respect to flexibility is positive. Thus, operating costs are convex in flexibility:

$$\frac{\partial^2 OC_y^c}{\partial F^2} = \begin{cases} 0, & \theta_y < \theta_F(F), \\ 2T\gamma_1 \left(1 - \frac{2\gamma_1 F}{\beta\theta_y}\right) \geq 0, & \theta_y \geq \theta_F(F). \end{cases} \quad (38)$$

Cross-derivative. Differentiating the marginal operating-cost effect of flexibility with respect to the annual volatility state yields

$$\frac{\partial^2 OC_y^c}{\partial \theta_y \partial F} = \frac{\partial m(F, \theta_y)}{\partial \theta_y} = \begin{cases} 0, & \theta_y < \theta_F(F), \\ -\frac{T\beta}{2} \left[1 - \left(\frac{2\gamma_1 F}{\beta\theta_y}\right)^2\right], & \theta_y \geq \theta_F(F). \end{cases} \quad (39)$$

Since $2\gamma_1 F \leq \beta\theta_y$ in the binding regime, the cross-derivative is non-positive. Thus, higher volatility weakly increases the marginal operating-cost benefit of flexibility.

B.4 Risk-averse flexibility investment

The risk-averse firm minimizes risk-adjusted total costs using the CVaR objective ($\omega > 0$):

$$\min_{F \geq 0} TC_{RA}^c(F) = \lambda F + (1 - \omega) \mathbb{E}[OC_y^c(F)] + \omega \text{CVaR}_\alpha^c(F). \quad (40)$$

From the risk-neutral analysis, we know that expected marginal operating costs are identical across contract types. Hence, differences in risk-averse investment can only arise through the CVaR objective. To derive the optimal relative investment between the two hedges, it is thus sufficient to analyze the effect of the CVaR. We proceed in two steps: First, we show how the location of the downside-risk states affects the marginal value of flexibility. Second, we characterize which volatility realizations constitute downside risk under the baseload and REP hedge.

B.4.1 Effect of shifting downside risk states

Recall that the marginal operating-cost effect of flexibility, $m(F, \theta_y)$ from (12), is weakly decreasing in θ_y . Additional flexibility therefore has weakly greater marginal operating value in higher-volatility states, as higher price volatility increases arbitrage revenue.

Let $S_\alpha^c(F)$ denote the set of volatility realizations that constitute the worst $(1 - \alpha) \cdot 100\%$ of annual operating costs under contract c . Because θ_y is continuously distributed, the marginal CVaR effect can be written as in (20), which summarizes the central mechanism.

$$\frac{\partial \text{CVaR}_\alpha^c(F)}{\partial F} = \frac{1}{(1 - \alpha)(\bar{\theta} - \underline{\theta})} \int_{S_\alpha^c(F)} m(F, \theta_y) d\theta_y.$$

While the marginal operating-cost function $m(F, \theta_y)$ is identical across contracts, contract design determines which volatility states receive additional weight through the CVaR.

Identical downside-risk states. Suppose that the REP and baseload contracts generate the same downside-risk set,

$$S_\alpha^{\text{rep}}(F) = S_\alpha^{\text{bl}}(F). \quad (41)$$

Then, their marginal CVaR effects coincide:

$$\frac{\partial \text{CVaR}_\alpha^{\text{rep}}}{\partial F} = \frac{\partial \text{CVaR}_\alpha^{\text{bl}}}{\partial F}. \quad (42)$$

This result is independent of whether the consumption schedule in the common CVaR interval is fully constrained, fully unconstrained, or crosses $\theta_F(F)$. Thus, the risk-averse investment conditions coincide and

$$\boxed{F_{RA}^{\text{rep}} = F_{RA}^{\text{bl}}}. \quad (43)$$

REP downside risk shifts toward higher volatility states. Now suppose that the REP downside-risk set shifts toward higher realizations of θ_y . Since $m(F, \theta_y)$ is weakly decreasing in

θ_y ,

$$\frac{\partial \text{CVaR}_\alpha^{\text{rep}}}{\partial F} \leq \frac{\partial \text{CVaR}_\alpha^{\text{bl}}}{\partial F}. \quad (44)$$

The inequality is strict whenever a positive-measure set of lower-volatility states is replaced by higher-volatility states over which $m(F, \theta_y)$ is strictly decreasing.

The first-order condition of the risk-averse firm is

$$\frac{\partial TC_{RA}^c}{\partial F} = \lambda + (1 - \omega)M(F) + \omega \frac{\partial \text{CVaR}_\alpha^c}{\partial F} = 0. \quad (45)$$

Since the first two terms are contract-independent and total costs are convex in F , (44) implies

$$\boxed{F_{RA}^{\text{rep}} \geq F_{RA}^{\text{bl}}} \quad (46)$$

The ordering is strict whenever the REP hedge shifts downside risk toward higher-volatility states over which the marginal operating value of flexibility is strictly greater.

The investment comparison therefore does not require the baseload CVaR states to be fully unconstrained or the REP CVaR states to be fully constrained. What matters is how contract design changes the volatility states contained in the CVaR.

B.4.2 Operating-cost risk across volatility states

The previous result reduces the investment comparison to the location of the downside-risk states. We therefore next characterize which realizations of θ_y enter the CVaR under each contract.

Baseload hedge. Under the baseload hedge, operating costs are strictly decreasing in θ_y in both operational regimes:

$$\frac{\partial OC_y^{\text{bl}}}{\partial \theta_y} = \begin{cases} -\frac{T\beta^2\theta_y}{6\gamma_1} < 0, & \theta_y < \theta_F(F), \\ T \left[-\frac{\beta F}{2} + \frac{2\gamma_1^2 F^3}{3\beta\theta_y^2} \right] < 0, & \theta_y \geq \theta_F(F). \end{cases} \quad (47)$$

Since the two operating-cost branches coincide at $\theta_F(F)$, baseload operating costs are continuous and strictly decreasing in θ_y , irrespective of whether the relevant realizations are constrained, unconstrained, or mixed consumption regimes. Hence, the worst $(1 - \alpha) \cdot 100\%$ of baseload realizations always corresponds to the lowest volatility states,

$$S_\alpha^{\text{bl}} = [\underline{\theta}, \theta_\alpha^{\text{bl}}], \quad \theta_\alpha^{\text{bl}} = \underline{\theta} + (1 - \alpha)(\bar{\theta} - \underline{\theta}). \quad (48)$$

REP hedge. Under the REP hedge, higher volatility has two opposing effects: it creates arbitrage opportunities but also increases exposure to the renewable delivery profile:

$$\frac{\partial OC_y^{\text{rep}}}{\partial \theta_y} = \begin{cases} \frac{T\beta\theta_y}{6\gamma_1} (4\gamma_1 - \beta), & \theta_y < \theta_F(F), \\ T \left[\frac{2\beta\theta_y}{3} - \frac{\beta F}{2} + \frac{2\gamma_1^2 F^3}{3\beta\theta_y^2} \right], & \theta_y \geq \theta_F(F). \end{cases} \quad (49)$$

For the constrained regime, define

$$x := \frac{2\gamma_1 F}{\beta\theta_y} \in [0, 1]. \quad (50)$$

Then

$$\frac{\partial OC_y^{rep, constrained}}{\partial \theta_y} = \frac{T\beta\theta_y}{12\gamma_1} [8\gamma_1 + \beta(x^3 - 3x)]. \quad (51)$$

Since $x^3 - 3x \geq -2$ for $x \in [0, 1]$,

$$\frac{\partial OC_y^{rep, constrained}}{\partial \theta_y} \geq \frac{\partial OC_y^{rep, unconstrained}}{\partial \theta_y}. \quad (52)$$

If $4\gamma_1 < \beta$, REP operating costs are decreasing in θ_y , but could be increasing in θ_y after regime change. The REP cost profile can therefore be non-monotonic. In this case, the location of the CVaR depends on the relative strength of the arbitrage and exposure effect, and therefore on the installed level of flexibility.

Consider first the benchmark in which the REP downside-risk set coincides with the baseload downside-risk set,

$$S_\alpha^{rep} = S_\alpha^{bl} = [\underline{\theta}, \theta_\alpha^{bl}]. \quad (53)$$

High volatility realizations begin to enter the REP CVaR once their operating costs exceed the cost at the marginal realization of this left-sided tail. The corresponding flexibility threshold F_{AE} is therefore implicitly defined by

$$OC_y^{rep}(F_{AE}, \bar{\theta}) = OC_y^{rep}(F_{AE}, \theta_\alpha^{bl}), \quad (54)$$

whereby F_{AE} refers to the optimal investment level at which the missing arbitrage revenues alone determine the CVAR states (Arbitrage Effect, AE).

Given (49), for

$$OC_y^{rep}(F, \bar{\theta}) > OC_y^{rep}(F, \theta_\alpha^{bl}) \quad (55)$$

the REP downside-risk set can no longer coincide with the purely left-sided baseload CVaR interval. Higher-volatility realizations enter the REP CVaR and replace lower-volatility realizations. Since the marginal operating-cost effect of flexibility is weakly decreasing in θ_y , this rightward shift makes the marginal CVaR effect of flexibility weakly more negative and therefore raises REP investment relative to the baseload hedge:

$$S_\alpha^{rep} \text{ shifted toward higher } \theta_y \implies F_{RA}^{rep} \geq F_{RA}^{bl}, \quad (56)$$

with strict inequality whenever the shift places positive probability weight on states in which the marginal value of flexibility is strictly larger:

$$\boxed{F_{RA}^{rep} > F_{RA}^{bl}}. \quad (57)$$

The threshold F_{AE} in (54) can be mapped into an investment-cost threshold λ_{AE} using the relevant optimal investment condition. Since higher investment costs reduce optimal flexibility, λ_{AE} provides an ex-ante characterization of the investment-cost environment in which high-volatility states begin to enter the REP downside-risk set. When a closed-form expression is cumbersome, λ_{AE} can be characterized implicitly by (54) together with the investment first-order condition and evaluated numerically.

Equally, a threshold F_{EE} (Exposure Effect, EE) exists above which exclusively the exposure effect is driving high-cost years. It can be mapped into an investment-cost threshold λ_{EE} using the relevant optimal investment condition. Since low investment costs increase optimal flexibility, λ_{EE} provides an ex-ante characterization of the investment-cost environment in which low-volatility states are not impacting the REP downside-risk set anymore. When a closed-form expression is cumbersome, λ_{EE} can be characterized implicitly by

$$OC_y^{rep}(F_{EE}, \underline{\theta}) = OC_y^{rep}(F_{EE}, \theta_\alpha^{rep}), \quad \theta_\alpha^{rep} = \bar{\theta} - (1 - \alpha)(\bar{\theta} - \underline{\theta}), \quad (58)$$

together with the investment first-order condition and evaluated numerically.

For completeness, the threshold F_{ES} (Equal Split, ES), derived from $OC_y^{rep}(F_{ES}, \bar{\theta}) = OC_y^{rep}(F_{ES}, \underline{\theta})$, can be mapped into an investment-cost threshold λ_{ES} . It provides an ex-ante characterization of the investment-cost environment in which the risk-neutral investment level ($F_{RA}^{rep} = F_{RN}^{rep}$) is reached.

B.4.3 A sufficient condition for an unambiguous result

A particularly transparent case arises if

$$\beta < 4\gamma_1. \quad (59)$$

As the derivative in the unconstrained regime is increasing in θ_y , this implies

$$\frac{\partial OC_y^{rep, constrained}}{\partial \theta_y} \geq \frac{\partial OC_y^{rep, unconstrained}}{\partial \theta_y} > 0. \quad (60)$$

REP operating costs are therefore strictly increasing in θ_y throughout both operational regimes. The REP downside-risk states are then unambiguously the highest-volatility realizations,

$$S_\alpha^{rep} = [\theta_\alpha^{rep}, \bar{\theta}], \quad \theta_\alpha^{rep} = \bar{\theta} - (1 - \alpha)(\bar{\theta} - \underline{\theta}). \quad (61)$$

Since the baseload downside-risk set remains left-sided, condition (59) guarantees that the REP hedge places additional risk weight on states in which flexibility has a larger marginal operating value. Hence,

$$\boxed{F_{RA}^{rep} > F_{RA}^{bl}}$$

Condition (59) is stronger than necessary. It guarantees a fully right-sided REP tail independently of the investment level. More generally, the investment ordering follows once condition

(55) is satisfied and high-volatility realizations enter the REP downside-risk set.

B.4.4 Graphical summary of results

Baseload hedge. Figure B.3 illustrates the baseload investment result. In both parameterizations, the risk-averse firm invests less in flexibility than the risk-neutral firm. The reason is that baseload downside risk is concentrated in low-volatility states, where spot-market arbitrage opportunities are limited and additional flexibility has comparatively little marginal value. Risk aversion therefore shifts weight toward states in which flexibility is less valuable and weakens investment incentives. This result is independent of whether β is above or below $4\gamma_1$.

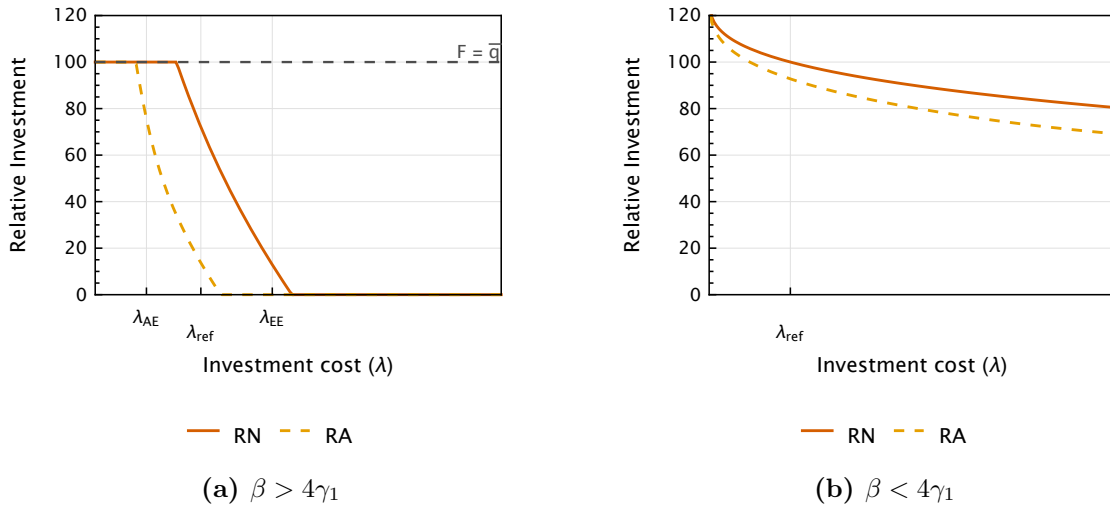


Figure B.3: Baseload flexibility investment as a function of investment cost

Note: Investment levels are normalized relative to investment at the benchmark λ_{ref} , which is the investment cost level at which risk-neutral investment is equal to the risk-averse investment level under the REP-hedge (Panel a) or λ_{ref} is chosen such that the risk-neutral flexibility threshold equals the midpoint of the θ -support (Panel b).

REP hedge. Figure B.4 shows how REP investment depends on the location of downside risk. When $\beta > 4\gamma_1$ (Panel a), REP operating costs can be non-monotonic in volatility. For low investment costs, firms install substantial flexibility and downside risk is concentrated in low-volatility states, so risk aversion reduces investment. As investment costs rise and flexibility becomes scarcer, high-volatility states increasingly enter the CVaR. Since flexibility has greater marginal value in these states, the investment effect of risk aversion reverses. The thresholds λ_{AE} and λ_{EE} separate the regions in which the arbitrage and exposure effects, respectively, unambiguously determine the investment response.

Under the sufficient condition $\beta < 4\gamma_1$ (Panel b), REP operating costs are strictly increasing in volatility. Downside risk is therefore always concentrated in high-volatility states, where additional flexibility is particularly valuable. Risk aversion consequently increases REP flexibility investment relative to the risk-neutral benchmark.

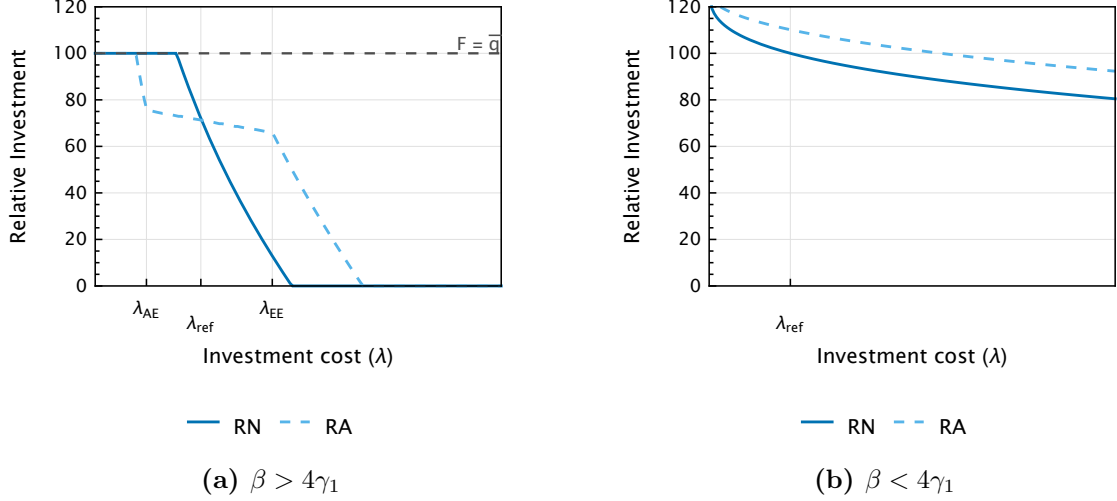


Figure B.4: REP flexibility investment as a function of investment cost

Note: λ_{AE} and λ_{EE} denote the investment-cost thresholds associated with the arbitrage and exposure effects, respectively. Investment levels are normalized relative to investment at the benchmark λ_{ref} , which is the investment cost level at which risk-neutral investment is equal to the risk-averse investment level under the REP-hedge (Panel a) or λ_{ref} is chosen such that the risk-neutral flexibility threshold equals the midpoint of the θ -support (Panel b).

B.5 Sensitivity of the threshold levels λ

Section 5.3 highlighted the importance of the threshold levels λ_{AE} and λ_{EE} , which determine at which levels of investment costs the arbitrage or exposure effect dominates. Here, we test the sensitivity of these threshold levels to the adjustment cost parameter γ_1 , to the risk aversion parameters ω and α , the strength of the negative correlation of prices and renewable supply β , and the two parameters governing the volatility of electricity prices and renewable supply $\bar{\theta}$ and $\underline{\theta}$.

The sensitivity analysis shows that the threshold values are mainly driven by the cost and correlation parameters. Higher adjustment costs γ_1 sharply reduce both thresholds, as investments become less profitable with high adjustment cost and the sufficiency condition ($\beta < 4\gamma_1$) is reached. Stronger price–quantity correlation β increases the value of flexibility and raises the thresholds, as higher price dispersion increases arbitrage benefits from flexibility.

The bounds of the VRE and thus price distribution affect the two channels asymmetrically: $\underline{\theta}$ matters primarily for the arbitrage threshold λ_{AE} , whereas $\bar{\theta}$ mainly affects the exposure threshold λ_{EE} .

The parameter of the confidence interval α has little effect on the threshold levels (max. +5%). This is consistent with it changing the mass of eligible states rather than the marginal profitability condition. The risk-weight parameter ω affects thresholds only indirectly: by shifting weight between expected cost and the CVaR, it changes the endogenous baseline flexibility level F , which in turn changes the marginal-value schedule and the threshold values.

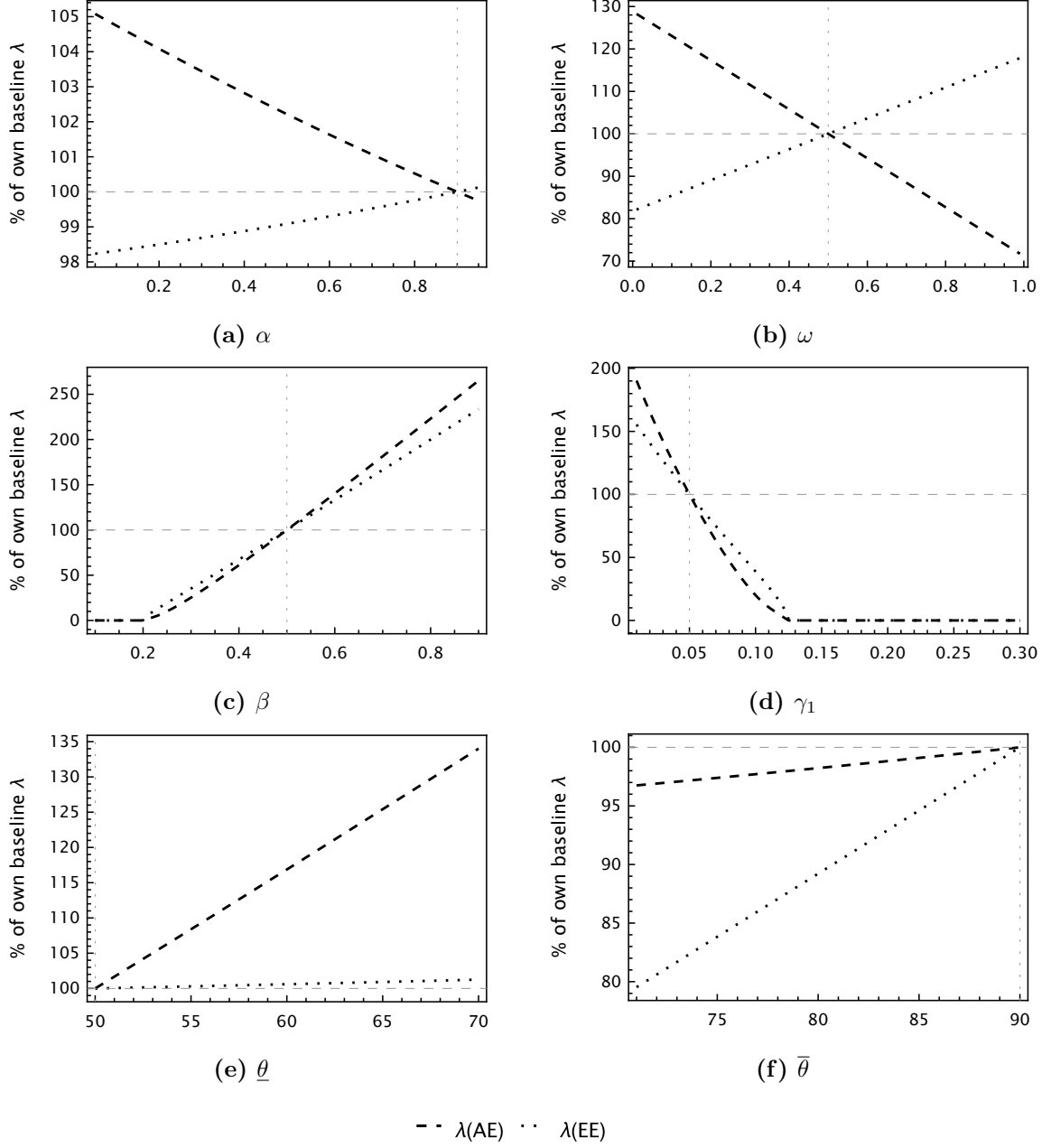


Figure B.5: Sensitivity of the threshold values λ_{AE} and λ_{EE}

Note: The plot shows the sensitivity of the threshold values to the selected parameter, keeping other parameters constant. The gray cross-lines indicate the result of the baseline specification. Cost levels above the black dashed line indicate an additional investment for risk-averse investors due to the REP-hedge over and above the baseload contract. Cost levels above the black dotted line indicate environments in which the investment for risk-averse investors under the REP-hedge is entirely driven by high θ_y realizations (exposure effect).

C Numerical Simulation

C.1 Construction of synthetic annual price-renewable distributions

This appendix describes how additional synthetic years are constructed from the seven available simulated weather years. The general idea is to treat each year as an unordered joint distribution of hourly electricity prices and renewable generation, estimate how these annual distributions vary across weather years, and then draw new annual distributions from this estimated cross-year distribution. The appendix first describes the underlying data, then explains how the joint price-renewable distribution is discretized and estimated, and finally shows how synthetic weather years are drawn from the fitted model.

Data basis. The construction of synthetic weather years is based on simulated electricity market data from [Klaucke et al. \(2026\)](#). Their model simulates the German electricity market in 2030 under a scenario with 80% renewable electricity generation and an advanced reliability reserve. The data contain hourly electricity prices and renewable generation for $Y_0 = 7$ historical weather years, covering the years 2008–2014, applied to the same 2030 market scenario. Hence, differences between years reflect weather-driven variation rather than changes in installed capacity. The resulting price duration curves are shown in Figure C.1. Electricity prices are implicitly capped at $500 \frac{\text{€}}{\text{MWh}}$, since the reliability reserve starts generating at this price and is assumed to have sufficient capacity to meet demand in all hours. Prices are also bounded below by zero, as surplus renewable generation can be curtailed at zero cost.

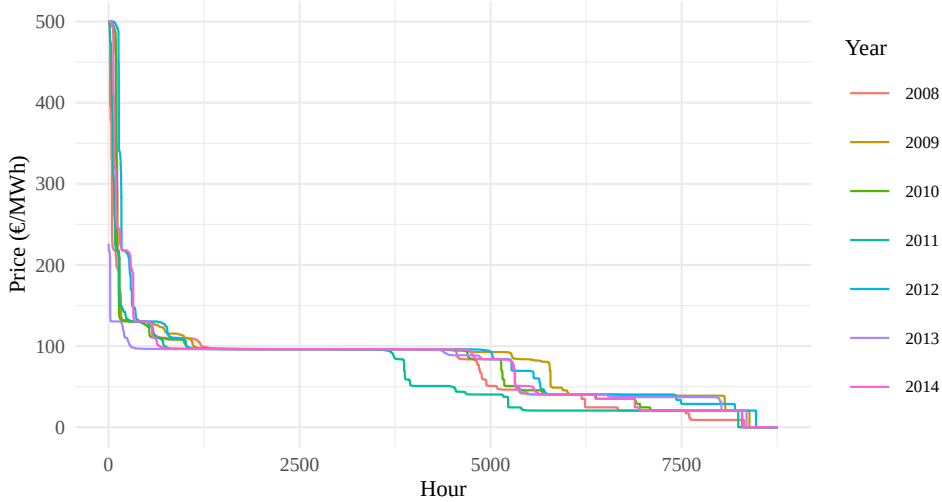


Figure C.1: Price duration curves of the seven basis weather years

Estimation of annual joint distribution. For each weather year, we treat the hourly observations of electricity prices and renewable generation as unordered draws from an annual joint distribution. This is valid due to our assumption of perfect foresight within years. Let $y = 1, \dots, Y_0$ index the available weather years, with $Y_0 = 7$, and let $t = 1, \dots, 8760$ index hours within a year. Each observation is given by the pair (p_{yt}, R_{yt}) .

The joint support of prices and renewable generation is discretized into a fixed two-dimensional grid. Prices are divided into B_P fixed-width bins and renewable generation into B_R fixed-width bins. This gives a full grid of $B_P \times B_R$ possible price-renewable cells. Since not all price-renewable combinations are observed, the estimation is restricted to active cells, defined as cells with at least one observation across the seven weather years. Let K denote the number of active cells.

For each year y , the hourly observations are converted into a vector of cell counts,

$$n_y = (n_{y1}, \dots, n_{yK}),$$

where n_{yk} denotes the number of hours in year y that fall into active cell k . By construction,

$$\sum_{k=1}^K n_{yk} = 8760.$$

The annual cell counts are modeled using a hierarchical Dirichlet-multinomial specification. Conditional on the year-specific probability vector π_y , the counts follow

$$n_y \mid \pi_y \sim \text{Multinomial}(8760, \pi_y).$$

The year-specific probability vectors are assumed to be drawn from a common Dirichlet distribution,

$$\pi_y \sim \text{Dirichlet}(\alpha m),$$

where m is the pooled empirical distribution over active cells and α is a concentration parameter. The vector m describes the average annual joint price-renewable distribution, while α controls how strongly individual weather-year distributions vary around this average. The concentration parameter α is estimated by maximizing the Dirichlet-multinomial likelihood.

The number of price and renewable-generation bins is selected through in-sample tuning. For each candidate grid, synthetic annual distributions are generated and compared to the original seven weather years. The benchmark grid is selected by minimizing the mean squared error of standardized deviations between synthetic and observed annual mean prices and annual mean renewable generation. Since only seven weather years are available, the same sample is used for both tuning and evaluation.

Generation of synthetic weather years. Synthetic weather years are generated in two steps. First, a new annual probability vector over active price-renewable cells is drawn from the estimated cross-year distribution,

$$\pi^* \sim \text{Dirichlet}(\hat{\alpha} \hat{m}).$$

This vector represents the joint price-renewable distribution of one synthetic weather year.

Second, hourly cell assignments for the synthetic year are drawn from

$$n^* \sim \text{Multinomial}(8760, \pi^*).$$

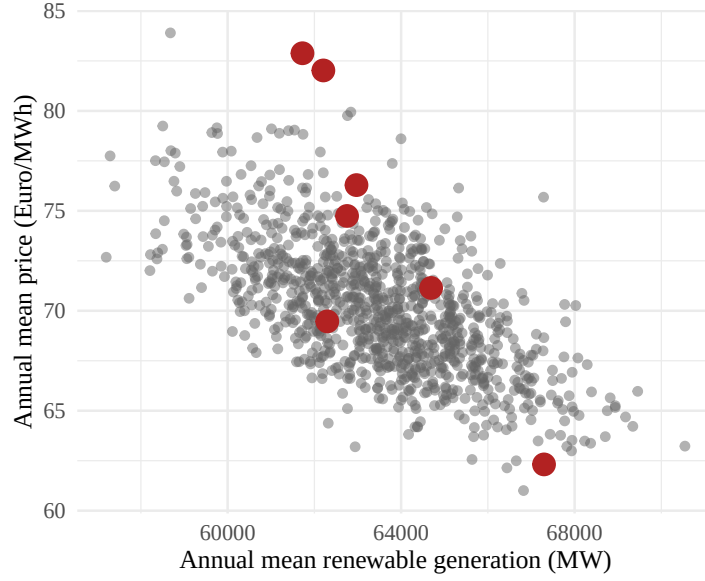


Figure C.2: Comparison of basis years and synthetic years

This determines how many hours of the synthetic year fall into each active price-renewable cell. To obtain continuous hourly price and renewable-generation values, observations assigned to a cell are drawn uniformly within the corresponding price and renewable-generation bin boundaries. This produces synthetic unordered annual samples of 8760 hourly price-renewable pairs while preserving the estimated joint distribution across weather years. Figure C.2 compares the $Y=1000$ synthetic years generated using the tuned bin specification ($B_P = 20$, $B_R = 20$) with the seven underlying weather years in terms of mean renewable generation and mean electricity prices.

C.2 Intra-annual optimization

Figure C.3 illustrates the solution to the within-year production problem under the risk-neutral optimal investment in flexibility ($\pm 17\%$). Since procurement contracts do not affect the physical consumption decision in the model, the optimal hourly demand schedule is independent of the procurement type. The figure therefore depicts optimal hourly demand q_{yt} across all synthetic years for the risk-neutral flexibility level.

Panel (a) shows that optimal demand decreases with the spot electricity price. At high prices, the firm reduces production below the baseline demand level in order to avoid costly electricity consumption. By contrast, at low prices, the firm increases production above the baseline level. However, the response is bounded by the installed flexibility capacity and, more importantly, moderated by increasing adjustment costs. Large deviations from base demand are only optimal when the electricity price realization allows for significant savings from shifting demand to outweigh the variable cost of adjustment.

Panel (b) shows that most hourly production choices remain close to the base demand level. This reflects that the majority of price realizations are not sufficiently far from the annual average to justify large deviations. The firm therefore utilizes its maximum downward flexibility capacity only in few hours with very high prices. Since the annual production target

must be met, reductions in high-price hours have to be compensated by higher production in other hours. Because there are fewer sufficiently attractive low-price hours and because upward deviations are also costly, the firm requires less upward flexibility than the maximum downward adjustment observed in high-price hours. Together with the relatively high variable adjustment costs compared to the investment costs of flexibility, this explains why the optimal production strategy is concentrated close to base demand and uses the flexibility bounds only in exceptional price situations.

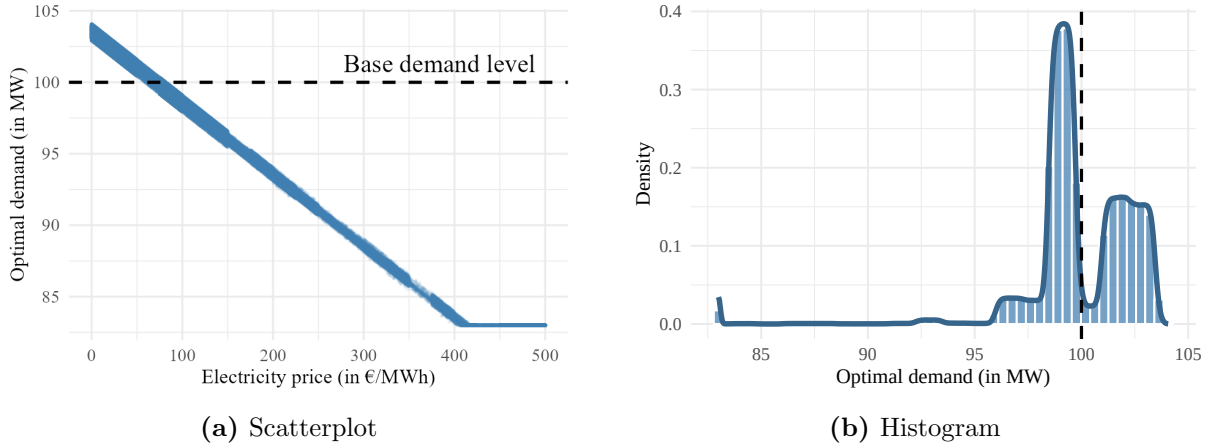


Figure C.3: Risk-neutral optimal hourly electricity demand across 1000 synthetic years

C.3 Annual operating costs and year characteristics

Figure C.4 plots annual operating costs under optimal flexibility investment against characteristics of the different synthetic years.

Without any price or volume risk, operating costs with the baseload hedge are stable across years. The firm is thus protected from downside risks, with only a slight chance to realize upside risks. These can be seen from the slight negative relationship between baseload operating costs and mean annual electricity prices: in years with high annual electricity prices, the firm gets a fixed amount of electricity, the market value of which lies above the hedge price. A similar slightly negative relationship can be seen with the within-year standard deviation of the price: higher within-year volatility increases the price spreads that can be arbitrated using flexibility, decreasing annual operating costs.

The firm with pure spot market procurement without any hedging has much higher volatility of annual operating costs. It has full price risk, which leads to a strong dependence on mean annual prices. When mean annual electricity prices are high, annual operating costs are also high. Higher standard deviation of within-year electricity prices also leads to higher annual operating costs, through the channel of mean prices: years with high price variability are strongly correlated with years with high mean prices.

The firm with the REP hedge is mostly exposed to profile risk, which arises from the difference between its own electricity consumption and the electricity supplied through the hedge. For the residual amounts, it is also exposed to price risk. However, the hedge does reduce the volatility of annual operating costs compared to pure spot market procurement.

This is also reflected in a moderately positive relationship between mean annual prices and annual operating costs.

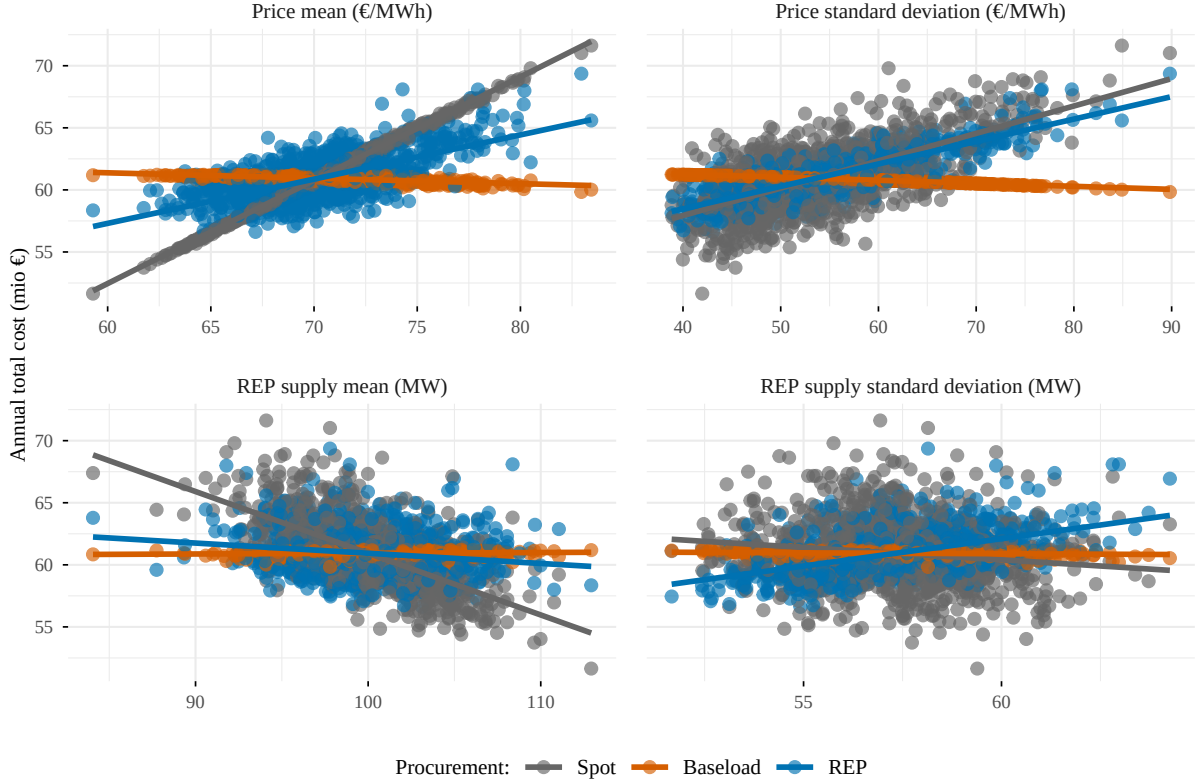
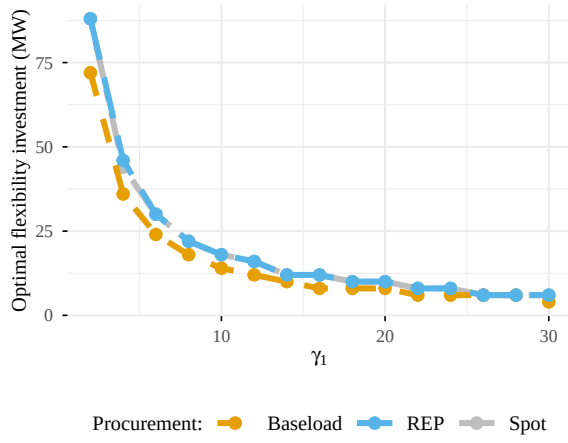


Figure C.4: Annual operating costs and year characteristics

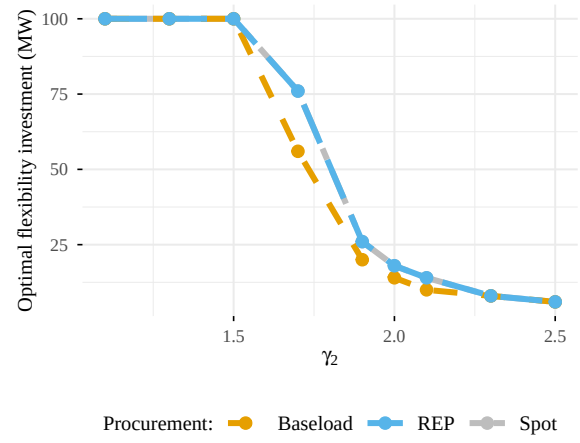
C.4 Sensitivity of the adjustment cost function

In Figure C.5, we vary the scale parameter γ_1 and exponent γ_2 of the adjustment cost function $h(q_{yt}) = \gamma_1 |q_{yt} - \bar{q}|^{\gamma_2}$, keeping everything else equal. We see that under our benchmark assumptions ($\gamma_1 = 10$, $\gamma_2 = 2$) and risk aversion, adjustment costs are already high, leading to relatively low optimal flexibility investments. Importantly, the qualitative finding of the relative investments across contract types remains stable: baseload firms invest less in flexibility than REP and spot firms.

At exponent parameters $\gamma_2 < 1.5$, optimal flexibility investment reaches its bounds of 100 MW. As we model flexibility as a symmetric increase and decrease in load-shifting potential, the firm cannot decrease consumption by more than its benchmark value $\bar{q}$. This is also in line with the general mechanism: when flexibility is sufficiently cheap (in investment or in anticipated adjustment costs), firms invest irrespective of the contract type.



(a) Scale parameter γ_1



(b) Exponent γ_2

Figure C.5: Sensitivity of the adjustment cost function parameters