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# THE INSUARANCE VALUE OF RENEWABLE ENERGIES

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**Abstract**

Solar and wind power are energy sources which, by their very nature, give rise to a degree of uncertainty, considering their variability depending on weather conditions. However, unlike many phenomena in the energy field (geopolitical shocks, institutional changes, wars, etc.), the uncertainty generated by the deployment of renewable energies can be scientifically controlled and objectively predicted. Consequently, the penetration of renewable energies also provides forms of guarantee that need to be weighed against other types of energy supply strategies, such as long-term partnerships or diversification of hydrocarbon imports. The aim of this work is to assess and discuss how renewable capacity can serve as physical insurance for the electricity system, in particular against gas supply shocks, which we believe is appropriate in the aftermath of the 2022 crisis (and its extensions in the coming years). To this end, we define the framework for assessing the economic value of a capacity in a context of uncertainty. Next, we consider two ways of assessing outcomes in the electricity spot market: according to the policy objectives of cost and price stability. We show that, in both cases, the value of a capacity can be expressed as an addition of two components: one aligned with the spot market outcome, and the other emerging from the willingness to pay for additional risk protection, underlining the need for an additional structure to organize the electricity sector. Finally, we test this framework in a forward-looking model of the French electricity system in 2030, where a shock to gas supply is taken into account. The numerical results show that solar and wind power are effective tools for managing gas-related risks, despite their variable output. In addition to the environmental benefits, this work suggests that there may be a new incentive for public intervention to support the development of renewable energies, based on this insurance value.

**Keywords:** economic value, electricity generation investments, positive externalities, risk management, strategic choice, variable renewables.

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## I. INTRODUCTION

Following the start of the Ukrainian war in 2022, the long-term partnership some European countries had with Russia to get cheap energy was in jeopardy. This led to a historical gas supply crisis, pushing European wholesale electricity prices to unprecedented heights. In response, governments approved significant emergency packages to protect consumers. Between 2022 and 2023, the fiscal cost of household support measures represents for the European Union (EU) more than 2 % of its Gross Domestic Product (GDP). For France, this number doubles and reaches 4 % of its GDP (ACER, 2023). The size of such public interventions highlights the need for better policies to reduce price risk. It also raises the question of the efficiency of public intervention: could this situation have been avoided if the emergency packages had been invested ahead of the crisis in preventive actions? For example, energy efficiency or renewable development have the double benefits of increasing energy security and mitigating climate change. REPowerEU is the European answer to the energy crisis (European Commission, 2022). This plan proposes three main lines of action to cut the EU's reliance on Russian gas: energy efficiency, fuel supply diversification, and renewable development. Because energy efficiency constitutes a no-regret solution to the intertwined problems of energy security and climate change but has limited potential, this paper will focus on the two remaining pillars of the EU strategy.

Diversification is a common answer to supply chain threats. Within the REPowerEU framework, fuel diversification encompasses the development of Liquefied Natural Gas (LNG) imports, non-Russian pipeline gas supply, biomethane, and renewable hydrogen. In this context, the EU's gas demand in 2030 could be covered at 20 % by domestic supply, 30 % by LNG, and the rest by Russian and non-Russian pipelines (Ah-Voun et al., 2024). The 2022 energy crisis fully highlighted the difficulties caused by gas supply via pipelines. Because of counterparty risks, such supply strategies are not entirely safe. Purchased on the global market, the required infrastructures to import LNG do not lock the buyer and the seller in the same long-term interdependency. However, this strategy still possesses a few weak points regarding climate change and energy security. Firstly, the combustion of LNG emits greenhouse gases. Investing in the expensive and specific infrastructures required to ship and transport LNG threatens to create a lock-in for extended usages of carbon-intensive technologies. Secondly, LNG import capacities do not fully address the issue of supply security. Indeed, the main driving forces of supply and demand in the natural gas market in the coming years lie outside of Europe (IEA, 2023). Because the LNG market is shaped by extra-European economic factors, which cannot be controlled nor entirely predicted, there is no guarantee of lasting affordable LNG prices in the coming years. In 2023, tensions in the Middle East 'prolonged' the shock of 2022 caused by the war in Ukraine, with, for example, threats of interruption to gas flows in the Strait of Hormuz (since a larger proportion of European supplies comes from Qatar), whereas until now such a threat was confined to oil.

By contrast, located on the national territory, the electric production of technologies based on Variable Renewable Energy (VRE) sources like solar and wind is not subject to any fluctuation other than the one induced by weather conditions. In contrast to import diversification strategies, the output of VRE power plants, and therefore the protection that VRE brings to a country's energy supply, can be objectively forecast over the long-term using scientific methods. It is not subject to subjective anticipations and beliefs. Also, the security that VRE provides is not threatened by counter-party risks and agreements based on spurious unanimity. Russia's partnership with some European countries regarding gas supply was possible because the parties engaged were opposed regarding their perception of the subjective probabilities of a Russian default. Such misperceptions are possible because evaluating this situation relies on assessing subjective probabilities. VRE uncertainty is objective and cannot lead to situations of spurious unanimity. In fact, VRE penetration acts as a protection for such situations, by reducing the size of the potential miscalculation. All estimates of the probability and size of the next gas shock are legitimate. The same is not true regarding VRE uncertainty as it is based on a physical process. Therefore, given a fixed energy demand, higher penetration of renewables reduces the consequences of an incorrect estimate of the next gas shock.

In canonical economic models, financial markets allow agents to trade risks such that equilibrium in those markets induces a Pareto optimum regarding their expected utilities, but also regarding their ex-post utilities, once uncertainty is resolved (Arrow, 1964; Dreze, 1970). However, markets are incomplete, and securities are not always available. Investments in physical assets may then complement financial contracts to reduce risks (Dimanchev et al., 2023). However, in that case, ex-post welfare, and therefore collective risks, are affected by the hedging strategies and investment decisions of market participants. Hence, equilibrium on hedging markets loses its normative appeal to guide collective action, as it is unclear how ex-post welfare and aggregate risks should be based on individual subjective beliefs and propensity to gamble. This yields the need to explore other economic frameworks to assess the evolution of the power system under uncertainty, especially to enforce a particular strategic vision such as a reduced reliance on Russian gas.

To summarize, import diversification, renewable domestic production, and financial contracts are three strategies for managing price risks. However, choosing the socially optimal mix of hedging strategies is challenging as it relies on evaluating subjective probabilities, and traditional market mechanisms based on individual beliefs and risk preferences do not guarantee, in that case, to yield optimal collective protection. Therefore, in this work, we propose to evaluate investment decisions in the power system using collective utility functions. Two of them will be considered, reflecting different representations of collective risks: one expressing the objective of cost stability and another one expressing the objective of price stability. This will enable us to explore other possibilities for the capacity mix than market equilibriums would allow and discuss the effects of the potential gap between individual and collective risk attitudes and beliefs. To study the relationship between the collective utility functions used and the outcome of the existing market structures, particular attention will be paid to the economic value of a capacity emerging from the two frameworks.

This paper first reviews the literature on the Generation Expansion Planning (GEP) problem under uncertainty. This section shows that if the impact of risk preferences on the optimal capacity mix is well documented, the nature and composition of the economic signal needed to stabilize the long-term equilibrium of the power sector, in this state, needs further investigation. In addition, the literature review reveals a lack of a framework to analyze the effect that price uncertainty has on agents using a collective utility function because of the problem raised by the interpersonal comparison of utilities. In the next section, we draw a framework to evaluate the economic value of a capacity in a stochastic context. This methodology is applied to get the economic value of a power plant relative to the policy objectives of cost and price stability. We show that in both cases, the economic value of a generating unit is an addition of two components: the variation in expected surplus and the reduction of the risk premium. The first item is well captured in spot markets under marginal pricing. The second item, however, highlights the need for additional structure to organize the power system so its long-term equilibrium is aligned with its economic optimum. Those results also allow us to formally show how power capacities act as physical insurance by providing the same hedging value as financial contracts. In the subsequent section, a numerical estimation based on a prospective model of the French power system in 2030 is performed. The results show that solar and wind act overall as insurance for the power system when a shock on gas is considered despite their uncertain production. Those results are additional arguments for the public support of VRE. Indeed, this shows that VRE can play a key role in the French energy security strategy and actively participate in price stability, while those social benefits are not necessarily conveyed through market mechanisms. Finally, the last section concludes the paper.

## II. LITERATURE REVIEW

GEP models answer the need for designing optimal investment programs in the electricity sector. Anderson (1972) traces back the first developments of the field to the mid-1950s with the application of linear optimization models to size power capacities. Since, improvements in modeling techniques allow the integration of new considerations under the GEP problem, such as the development of regulatory constraints, inter-sectoral coupling, or the effects of uncertainty and risk preferences (Koltsaklis and Dagoumas, 2018).

To study the effects of risk on the optimal investment schedule, a first approach is to consider risk-neutral preferences. Gorenstin et al. (1993) illustrate how the objective of minimizing operational and investment costs can be extended to a risk-neutral setting using a probability-weighted objective function. The solution found is optimal on average for every scenario under study. Possible sources of uncertainty in the power system are numerous, such as demand forecast errors, power plant outages, or fuel costs. With the development of VRE, a growing literature tackles the uncertainty related to their intermittency (Swider and Weber, 2007; Fürsch et al., 2014; Spiecker and Weber, 2014; Wu et al., 2017).

However, risk aversion is a natural feature of agents' behavior. Awerbuch and Berger (2003) propose an adaptation of the mean-variance portfolio theory traditionally used in the financial field to optimize the European electric system and investigate the effect of various risk profiles on the power sector. Multiple contributions have then extended this method. Huang and Wu (2008) use load duration curves to minimize a risk-weighted objective function based on generation costs, their variance, and a degree of risk aversion. Delarue et al. (2011) extend those previous works and create an investment model that minimizes cost and risk, taking into account the actual hour-by-hour load pattern. In those models, risks are measured through the dispersion of the outcome of a random variable. They take the perspective of a risk-averse planner concerned about cost stability.

Models that optimize costs and risks jointly can find the optimal capacity mix when risk aversion is considered. However, the economic value of a capacity is only captured through shadow prices, derived from the constraints of the optimization program. The value of risk management that each capacity provides is not directly defined: the composition of the economic signal needed to reach the objective of cost stability is not derived from the simulation. To fill this gap, assessing the full economic value of a power capacity through the lens of a risk-averse planner is necessary. This way, it will be possible to find the accurate economic incentive that would complement spot market revenues and guide investments toward a socially optimal capacity mix.

Risk aversion can also be considered at the level of market participants. Indeed, consumers and producers in electricity markets can display risk aversion, impacting their willingness to pay or their propensity to invest in power capacities (Neuhoff and De Vries, 2004; de Maere d'Aertrycke et al., 2017; Bichuch et al., 2023). To tackle this problem, agent-based approaches have been developed, investigating the GEP problem with more realistic features. Petitet (2016) uses concave utility functions to represent the risk aversion over the dispersion of outcomes of decision-makers regarding long-term investments, while a cost-minimization model still governs the short-term operation of the power system. Similarly, Anwar et al. (2022) use an optimization model to represent the daily operation of the electricity market combined with concave utility functions to analyze investors' risk aversion.

Stochastic equilibrium models are particularly suited to study how the risk attitude of market participants impacts the GEP problem. In such a framework, each actor maximizes its own objective function until an equilibrium is reached, accurately representing how competitive markets behave. For example, Fan et al. (2012) consider an equilibrium model to study the effect of risk aversion on investments in high or low-carbon technologies under the tradable allowance system. Kaminski et al. (2023) formulate an equilibrium problem to investigate a capacity market with risk-averse participants. Depending on the goal of the study, various representations of risk can be used for stochastic equilibrium analysis (Schiro et al., 2016; Abada et al., 2017; Kaminski et al., 2022; Egging-Bratseth and Siddiqui, 2023).

Agent-based models and equilibrium models look to emulate agents' behavior as realistically as possible, proposing a descriptive view of electricity markets. However, because of the difference in subjective probabilities between market participants and the planner, as well as the potential gap between individual and collective risk attitudes, it is not clear how the outcome of a competitive market aligns with society's preferences in a stochastic context. Assessing the full economic value of a power capacity for a regulator, taking into account the perspective of both consumers and producers, can give new insights into the role that uncertainty plays in widening this gap. However, the problem of the interpersonal comparison of utilities is an obstacle to drawing meaningful results from additive collective utility functions (Bichuch et al., 2023).

The approach presented in the current paper aims to investigate the willingness to pay for power capacities and study how VRE can act as insurance against gas price shocks. It is an adaptation to the context of electricity markets of the framework developed by Baumgärtner and Strunz (2014) to evaluate the value of biodiversity. Baumgärtner and Strunz break down the economic value that biodiversity provides to a planner looking to maximize its expected utility and identify what part of it comes from its ability to manage risk. However, this representation of preferences under uncertainty is limited to embodying the objectives of price and cost stability for the power system. In the current work, Baumgärtner and Strunz's setup is extended to encompass a larger representation of society's preferences through the use of dedicated collective utility functions. This extension allows us to apply this framework in a market environment. Ultimately, this will enable us to lift the problem of the interpersonal comparison of utilities within collective additive utility functions. This extends the literature related to the stochastic GEP problem by proposing a new normative approach to represent the power system based on collective additive utility functions. This also adds to this branch of the literature by proposing a decomposition of the economic value of a power capacity for various policy goals, giving new insight into how additional structures are needed to complement the spot market when risk preferences are considered. This framework is also used to formally show how power capacities act as physical insurance for the power system and can play the same role as financial insurance contracts to hedge risks. Finally, this also allows us to investigate how VRE can be used as a strategic tool to manage uncertainties in the electricity market.

## III. THEORETICAL FRAMEWORK

The power sector is governed by a succession of markets designed to organize electricity production throughout different timescales. In this regard, the spot market based on marginal pricing acts as a reference point for other markets and drives their prices. However, the European governments' response to the energy crisis shows that, if needed, the infra-marginal rent of producers can be redistributed to consumers as emergency measures, moving producer's revenues closer to their production costs. In this extreme case, profits are set to zero, and costs are the only drivers of uncertainty for market participants. Therefore, a cost perspective and a price perspective will be used as extreme cases to represent collective risks and frame how the power sector can behave in times of crisis.

In this section, we first review the two optimization problems we use to represent those two perspectives on the electricity sector. Then, we describe the methodology we implement to break down the economic value of a power capacity. Finally, we present the results of the method when applied to our models of the power system and their interpretations regarding public intervention

### 3.1. Models description

The representation of uncertainty is common to the two optimization models. To define the lottery of market participants, we consider that $n \in \mathbb{N}$ states of the world are possible with a fixed probability of occurrence $(\alpha_i)_{1 \leq i \leq n}$.

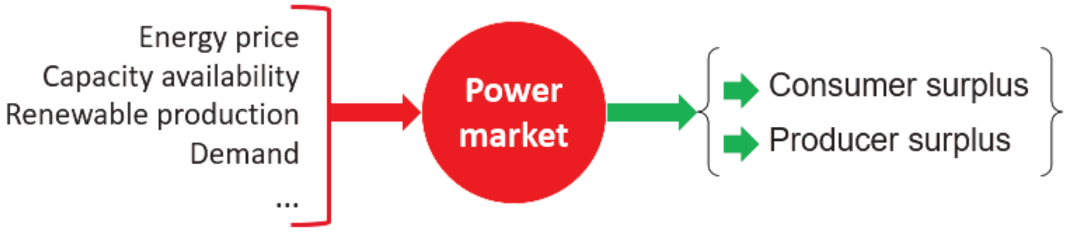


Figure 1: Schematic view of the power system for a given state of the world (source: author's proposition)

As shown in figure 1, each state of the world corresponds to a set of annual inputs for the power system (capacity availability, energy prices, demand, etc.). For each of these scenarios, the deterministic operation of the electricity market fixes the price and short-term cost of electricity at each moment of the year. In return, this sets the consumer and producer surpluses, which are the outcomes of the lottery that market participants face. Figure 2 shows how the market equilibrium gives the price and the variable costs needed to produce electricity.

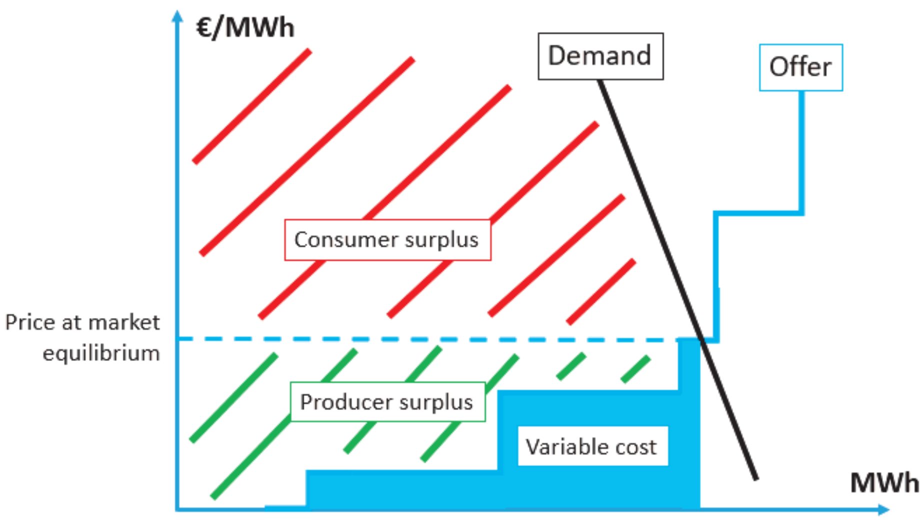


Figure 2: Schematic view of the electricity market (source: author's proposition)

We will use a concave utility function to emulate risk preferences so that agents display constant absolute risk aversion. This approach is largely used to study the GEP problem (Schiro et al. 2016; Petitet, 2016; Abada et al., 2017). It translates an aversion to the dispersion of possible outcomes and their unpredictability. It will allow us to study the trade-off between a low-impact and high-probability risk, namely renewable uncertainty, and a low-probability but high-impact risk, namely a shock on gas supply.

#### 3.1.1. A cost perspective

The first optimization problem embodies the view of a risk-averse planner concerned about the consumer surplus $CS$ (in €) and the producer surplus $PS$ (in €) that occur in the different states of the world in the electricity spot market, as well as the fixed costs $FC$ (in €). Here, the social surplus after the resolution of uncertainty drives collective actions. One configuration of the power system is preferred to another if it increases the collective utility function $CUF_1$ defined by:

$$CUF_1 = \sum_{i=1}^{n} -\alpha_i e^{-\rho(CS_i+PS_i-FC)} \qquad \text{with } \rho > 0 \tag{1}$$

Here, we assume the planner displays constant absolute risk aversion with a coefficient $\rho$ (in €$^{-1}$). With a fixed capacity mix, a competitive electricity market maximizes the consumer and producer surplus in each state of the world. In this paper, $CUF_1$ is said to translate a cost perspective because in each state of the world, the price that occurs in the electricity market is irrelevant for risk assessment.

#### 3.1.2. A price perspective

For the second optimization framework, we consider that the expected utility of agents is a legitimate driver of collective actions. In this context, society should take into account the risk on electricity prices that consumers face, which justifies price stabilization policies. In this modeling framework, we assume that:

(I) Consumers' preferences for different power system organizations can be described ex-ante by the expected value of a von Neumann–Morgenstern (vNM) utility function taking consumer surplus as an argument,

(II) Firms are driven by expected profits, which can be interpreted as a utility function,

(III) Social preferences satisfy the vNM axioms over the set of social lotteries,

(IV) If consumers and producers prefer configuration A of the power system to configuration B or one is indifferent between the two, but the other prefers A to B, then society prefers A to B.

The social aggregation theorem of Harsanyi states that society's preferences can be represented by a function linear in the expected utility of agents (Harsanyi, 1955; Harsanyi, 1977). Therefore, the following collective utility function $CUF_2$ can guide collective actions:

$$CUF_2 = K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} + K_p \sum_{i=1}^{n} \alpha_i (PS_i - FC) \qquad \text{with } \rho_c, K_c, K_p > 0 \tag{2}$$

Here, the consumer is assumed to display constant absolute risk aversion with a coefficient $\rho_c$ (in €$^{-1}$) while firms are risk neutral. The coefficients $K_c$ and $K_p$ (no unit) represent how society favors consumers relative to producers. With a fixed capacity mix, the electricity market equilibrium sets in each state of the world consumer and producer surplus.

## 3.2. Economic value and insurance value

The framework described hereafter is an adaptation of the work of Baumgärtner and Strunz (2014) to evaluate the economic value of biodiversity. The method is conceptually extended to a market environment. The economic value of a good is assessed through the lens of a planner looking to maximize a collective utility function that embodies society's objectives and preferences.

### 3.2.1. Definitions

**Maximum willingness to pay**

The maximum willingness to pay for a good is the amount of money the buyer is willing to pay that leaves him indifferent about whether the transaction takes place or not. In that case, the utility $U$ of the buyer is the same before and after the transaction:

$$U(before\ the\ transaction) = U(after\ the\ transaction) \tag{3}$$

Let's notice that if the proposed price of a good is below the maximum willingness to pay, the transaction will occur as it increases the buyer's utility. Also, for the buyer, a good is purchased in optimal quantities when its price equals its maximum willingness to pay.

**Maximum willingness to pay of the planner**

In the same way, we can define the maximum willingness to pay for a good from a social perspective. Let's assume that a planner looks to maximize a collective utility function $CUF$. In that case, the maximum willingness of the planner to pay for a good satisfies the following equation:

$$CUF(before\ the\ transaction) = CUF(after\ the\ transaction) \tag{4}$$

This equation gives the maximum amount of money the planner is willing to spend in a transaction to acquire a new good according to the ethical preferences rooted in the collective utility function.

**Economic value under uncertainty**

In a context of uncertainty, we will define the economic value $V$ (in €/MW) of the capacity $C$ (in MW) of a particular technology as the ex-ante maximum willingness to pay $mWTP$ (in €) for a marginal addition $\Delta C$ of that capacity in the electricity mix:

$$V(C) = \lim_{\Delta C \to 0} \frac{mWTP(\Delta C)}{\Delta C} \tag{5}$$

**Risk premium**

Let's assume that the preferences over lotteries of a decision maker can be represented by a utility function $U$ equal to the expected value of a vNM utility function $u$, such that:

$$U = E[u(X)] \tag{6}$$

Here, $X$ is a random variable representing a lottery, and $E$ represents the expectation operator over the probabilities of the lottery $X$. In that case, the riskiness of a lottery for an agent can be expressed in monetary terms through its risk premium $\pi$ (in €), defined such that it satisfies the following equation:

$$u(E[X] - \pi(X)) = E[u(X)] \tag{7}$$

In other words, the risk premium is the maximum amount of money a risk-averse agent is willing to pay to erase uncertainty. When paying the risk premium, the agent is indifferent about whether he faces the risky situation represented by $X$ or its certainty equivalent, given by $E[X] - \pi(X)$.

**Insurance value**

Applying the framework of Baumgärtner and Strunz (2014), we will define the insurance value $I$ (in €/MW) of a capacity $C$ of a particular technology as its marginal ability to reduce the risk premium:

$$I(C) = -\frac{d\pi(C)}{dC} \tag{8}$$

### 3.2.2. A cost perspective

It is now possible to evaluate the economic value of a power-generating unit from the cost perspective. The complete demonstration of this formula is provided in appendix A. Using $CUF_1$ described in 3.1.1, it can be shown that the economic value $V_1$ of a capacity $C$ is an addition of two terms: the marginal variation in expected social surplus $E[SS]$ (in €), defined as the sum of consumer and producer expected surplus, and the insurance value $I_1(C)$ associated to the risk on social surplus. Assuming the same inelastic demand in each state of the world, the insurance value $I_1(C)$ of a capacity is solely defined relative to the risk on variable costs faced by the risk-averse planner.

$$V_1(C) = \frac{dE[SS]}{dC} + I_1(C) \tag{9}$$

The first component of the economic value, the marginal variation in expected social surplus, is the economic value when the collective utility function considered is simply composed of expected social surplus and fixed costs. It is the economic value under collective risk-neutral preferences. It is aligned with the outcome of a spot market under marginal pricing. Indeed, a market is at optimality for the social preferences considered if the economic value of each capacity is equal to its cost. Also, in a market under marginal pricing at long-term equilibrium, profits are set to zero, which means that the revenue that a capacity gets from the spot market is equal to its cost. So, a power market under marginal pricing at long-term equilibrium aligns for a capacity its economic value under risk-neutral preferences, its revenues, and its costs: they are all equal. Under risk-neutral preferences, the spot market alone guides investments toward the optimal capacity mix.

When risk aversion is considered, the profits occurring through the sales of electricity on the spot market, are not congruent with society's preferences and do not send adequate long-term signals. Indeed, in a spot market at long-term equilibrium, profits are set to zero while the full economic value of a capacity is still higher than its costs. So, collective choices are not optimized. An additional payment equal to the insurance value is needed to make additional capacities profitable and move the power system toward a capacity mix that reduces risks and is better aligned with collective preferences.

A strictly negative insurance value means that the planner is willing to reduce the revenues made by producers on the spot market to reduce the development of a particular technology in the capacity mix. For instance, this can be associated to an additional tax for technologies that induce additional risks in the power system.

### 3.2.3. A price perspective

Using $CUF_2$ described in 3.1.2, it can be shown that the economic value $V_2$ of a capacity $C$ is also an addition of two terms: the variation in expected social surplus $E[SS]$, and the insurance value $I_2(C)$ associated to the risk on consumer surplus. Assuming the same inelastic demand in each state of the world, the insurance value $I_2(C)$ is entirely set by the risk on electricity prices faced by the risk-averse consumer. The full demonstration and assumptions of this formula can be found in appendix A. The central assumption to deal with the problem of interpersonal comparison of utilities is that the planner is indifferent between giving one euro in each state of the world to consumers or producers. Other ethical considerations for the planner would yield other expressions of the economic value.

$$V_2(C) = \frac{dE[SS]}{dC} + I_2(C) \tag{10}$$

In the same fashion as the previous paragraph, this representation of the economic value allows us to derive an optimal policy for a planner that looks to stabilize prices and optimize expected utilities. A positive (negative) insurance value signals that the planner is willing to transfer money from consumers to producers (or conversely) outside the market so they can invest (reduce investment) in additional generating units and enhance the expected outcome of the electricity market. In that case, firms get revenues from the spot market and from the planner, so they can invest in a capacity mix that optimizes the satisfaction upon expectations of market participants.

### 3.2.4. Financial insurance

Now, let's consider the possibility of buying an insurance contract $F$ of the following form:

$$F = q(X - E[X]) \qquad \text{with } 0 \leq q \leq 1 \tag{11}$$

Here, $X$ represents a random variable (in €) and $E[X]$ is the expectation operator over the probabilities of $X$. For example, $X$ can be the price to pay for a specified amount of electricity or gas at a particular time of the year. $q$ is the portion of the risk insured (no unit). When $q = 0$, no risk is insured and when $q = 1$, the risk is fully insured. Here, no other additional cost for the buyer is considered (transaction cost, insurer profits, etc.).

The integration of $F$ to the cost perspective leads to the optimization of the following social welfare function:

$$CUF_{1*} = \sum_{i=1}^{n} -\alpha_i e^{-\rho(CS_i + PS_i + F_i - CF)} \qquad \text{with } \rho > 0 \tag{12}$$

We consider that the payment associated with the insurance contract is disconnected from the operation of the power system. For example, contracting insurance on gas costs does not change the merit order when the power system operates and does not lead to a change in gas consumption compared to the case without gas insurance.

The integration of $F$ to the price perspective leads to the optimization of the following collective utility function:

$$CUF_{2*} = K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i)} + K_p \sum_{i=1}^{n} \alpha_i(PS_i - CF) \qquad \text{with } \rho_c, K_c, K_p > 0 \quad (13)$$

Here, the insurance contract covers only the sources of uncertainty that consumers face. Especially, $F$ can represent an insurance against electricity price risk.

When evaluated through $CUF_{1*}$, the cost perspective, or through $CUF_{2*}$, the price perspective, the economic value of $F$, $V_F(q)$ (in €), is precisely its insurance value $I_F$(q) (in €). The complete demonstrations of the properties of $F$ are provided in appendix C and D:

$$V_F(q) = I_F(q) \quad (14)$$

This fully justifies the term insurance value for the part of the economic value of power capacities related to risk management and acts as self-insurance. This also formally shows that power capacities can act as physical insurance for the power system and consumers. This physical insurance avoids the short-comings of the market for long-term contracts as the lack of liquidity and counterparty risks.

## IV. CASE STUDY

This section presents a numerical application of the framework developed to evaluate the insurance value of a power capacity. Especially, the case study aims to evaluate how VRE can be used to hedge against a shock on gas supply and help stabilize costs and prices in the electricity market.

### 4.1. Simulation set up

#### 4.1.1. The modeling framework

We use the cost optimization model GenX to emulate the operation of the power system over the year in each state of the world (MIT, 2023). The results of this optimization can be interpreted as the outcome of a perfect electricity spot market at equilibrium under inelastic demand. The dual variable of the energy constraint is interpreted as a price. This assumption is common in energy system modeling (Prol and Schill, 2021; Mallapragada et al., 2021). Several supply and demand technologies can be modeled: demand-side response, storage, variable renewable energies, hydro capacities, etc. Here, GenX is executed to give an hourly representation of the electric system.

#### 4.1.2. Data

We model a power system based on the scenarios of the French TSO for the French power system in 2030 (RTE, 2021). One single node is considered for the electricity grid. The system is regarded as a copper plate without any interconnection or possibility to trade outside the simulated market. We primarily use data from the French TSO

(RTE, 2021). The gas and CO2 price projections to evaluate the variable cost of gas power plants are based on the World Energy Outlook 2022 (IEA, 2022). The cost and penetration of the different technologies are summarized in table 1. Different levels of photovoltaic (PV) and wind penetration are tested in this case study. However, those are built around a reference scenario of VRE development for 2030 of 35.1 GW of PV and 33.2 GW of wind capacities (RTE, 2021). A higher level of gas capacity is considered compared to the French TSO scenario to compensate for the lack of import capacity.

| | Capacity (GW) | Variable cost (€/MWh) | Yearly fixed cost (€/MWyear) |
|---|---|---|---|
| Solar PV | 35.1 | 0 | 30 000 |
| Onshore wind | 33.2 | 0 | 75 000 |
| Offshore wind | 5.2 | 0 | 126 000 |
| Nuclear | 59.4 | 10 | 165 000 |
| Hydro reservoirs | 10 | 0 | 120 000 |
| Daily pumped storage | 2.3 | 0 | 120 000 |
| Weekly pumped storage | 2.7 | 0 | 120 000 |
| Run-of-the-river hydro | 12.2 | 0 | 120 000 |
| Natural gas | 37.1 | 50 - 250 | 101 000 |
| Batteries | 0.5 | 0 | 38 000 |

Table 1: Capacity and costs of the power generating technologies (source: RTE, 2021; IEA, 2022)

Daily pumped storage aggregates pumped storage hydropower stations where the discharge time is lower than a few hours. Weekly pumped storage aggregates pumped storage stations where the discharge time is above 30 hours. The aggregate storage capacity of weekly pumped storage (89.9 GWh) is higher than the aggregate storage capacity of daily pumped storage (11.5 GWh). The variable cost of nuclear power plants is 10 €/MWh (RTE, 2021). Except for gas-fired power plants, the variable cost of other technologies is zero. The yearly fixed costs of wind and PV are set respectively at 75 000 €/MWyear and 30 000 €/MWyear (RTE, 2021). These last assumptions do not play a role in the short-term modeling of the power system. However, it is necessary to link the economic value of VRE with its socially optimal penetration. Indeed, this equilibrium is found when the total yearly cost of VRE equals their annual values. The fixed costs of other technologies are given by RTE (2021). They do not impact the simulation and are presented for comparison purposes only. The time series for demand, renewable load factors, and hydropower plant inflows are taken from the 2022 European Resource Adequacy Assessment (ENTSO-E, 2022).

We consider two sources of uncertainty in the power system: gas prices and VRE interannual variability. To recreate a shock on gas supply comparable to the one that occurred in Europe in 2022, we consider the possibility of a five-time increase of gas prices in comparison to the baseline scenario. The variable cost of gas-fired power plants can be 50 €/MWh or 250 €/MWh. We assume that the gas supply shock occurs once every fifty years. We consider two possible annual load factors to model solar and wind uncertainty: high and low. Those are chosen among the extreme climate years regarding VRE load factors in France: 1987 and 1989 for PV and 1985 and 1989 for wind (ENTSO-E, 2022). In 1987 and 1989 the average annual PV load factor is respectively at 13.8 %

and 15.9 %. In 1985 and 1989 the wind load factor is respectively at 26.7 % and 34.1 % on average over the year. We assume equiprobability between the high and low load factors of the two renewable sources to emulate high uncertainty. This way, if VRE have positive insurance values when a shock on gas is considered in this extreme case, it is also true for more realistic assumptions. Table 2 summarizes the eight possible states of the world and their probabilities.

| | |
|---|---|
| Low gas price / Low solar / Low wind<br>Prob. 0.245 | High gas price / Low solar / Low wind<br>Prob. 0.005 |
| Low gas price / High solar / Low wind<br>Prob. 0.245 | High gas price / High solar / Low wind<br>Prob. 0.005 |
| Low gas price / Low solar / High wind<br>Prob. 0.245 | High gas price / Low solar / High wind<br>Prob. 0.005 |
| Low gas price / High solar / High wind<br>Prob. 0.245 | High gas price / High solar / High wind<br>Prob. 0.005 |

Table 2: Possible states of the world and their probabilities

Measuring risk preferences is a complex exercise. In the literature, sensibility analysis generally supplants empirical works to explore the risk aversion of market participants (Bichuch et al., 2023). Quantifying the risk attitude of society is even more laborious. Hence, little significance should be attached to the precise numbers provided in the numerical estimation of this paper. However, because risk aversion is only a scaling factor for the results presented hereafter, the qualitative outcome of the simulation is still relevant.

The overall modeling process to get the economic value of a capacity is summarized in graph 3. Multiple states of the world defining a set of inputs for the power system are considered. Two capacity mixes are tested: with and without the marginal addition of a capacity. GenX is executed as a linear optimization model to emulate the electricity market equilibrium for the two power mixes in each state of the world. Comparing the results of the simulations allows us to compute the variation of the risk premium and the variation of expected surplus, which yields the full economic value of the capacity under study.

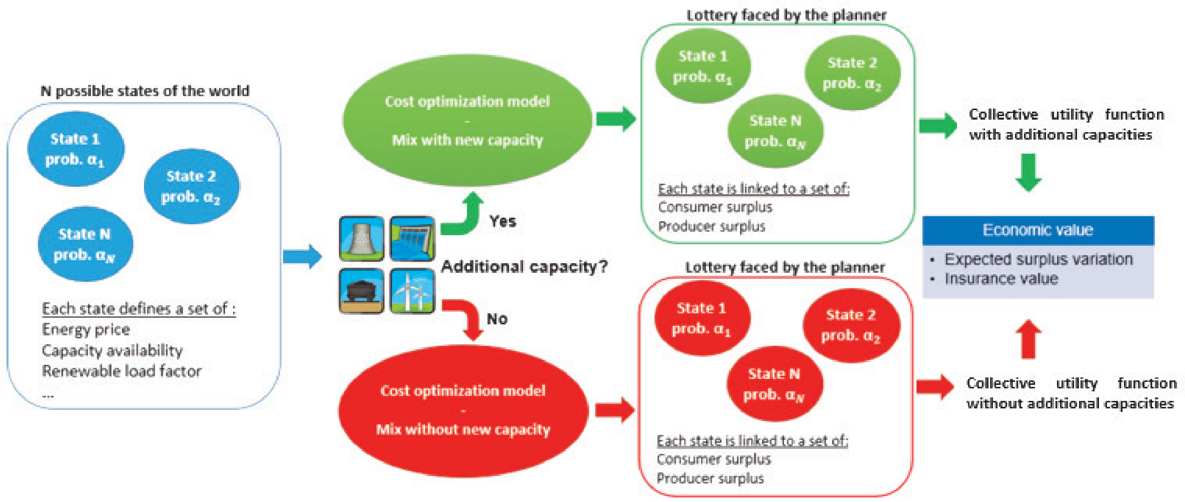


Figure 3: Schematic view of the modeling process (source: author's proposition)

### 4.2. Simulation results

This section presents only the insurance values of solar, wind, and dispatchable capacities. Indeed, for the insurance value of offshore wind and run-of-the-river hydroelectricity to be relevant, an explicit simulation of their inter-annual variability should have been considered. Also, only an increased penetration of solar and wind capacities is considered because those are the two technologies with the most potential for development in the French power system in the coming years.

#### 4.2.1. Cost perspective

In order to get numerical results, the risk aversion coefficient is arbitrarily fixed at 0.3 to evaluate the insurance value of VRE from a cost perspective. This is the reference value used throughout this section. However, sensitivity analyses are also performed.

**Renewable uncertainty only**

Table 3 displays the insurance value of solar PV, wind, and the different dispatchable technologies of the power system from a cost perspective when only VRE uncertainty is considered.

Wind capacities have a higher inter-annual variability than solar PV capacities. In this context, wind is the main source of uncertainty for the capacity mix under study, leading to a negative insurance value of -380 €/MW for wind capacities in the reference case. Despite its variability, solar PV stabilizes the power system's cost with a positive insurance value of 690 €/MW.

Natural gas capacities have an insurance value of exactly 0 €/MW. Additional capacities of gas-fired plants are not called in the merit order and do not provide any value

| Technology | Insurance value (€/MW) | | |
|---|---|---|---|
| | $\rho$ = 0.25 | $\rho$ = 0.3 | $\rho$ = 0.35 |
| Solar PV | 580 | 690 | 800 |
| Onshore wind | -310 | -380 | -440 |
| Nuclear | 3 160 | 3 790 | 4 410 |
| Hydro reservoirs | 690 | 820 | 950 |
| Daily pumped storage | 14 | 17 | 19 |
| Weekly pumped storage | 330 | 400 | 470 |
| Natural gas | 0 | 0 | 0 |
| Batteries | 1 | 1.5 | 2 |

Table 3: Insurance value from a cost perspective of the different technologies of the power system when only VRE uncertainty is considered

to the system. Batteries and daily pumped storage have negligible insurance value regarding the inter-annual variability of VRE because of their relatively small storage capacities. With a higher storage capacity, weekly pumped storage capacities have a non-negligible insurance value of 400 €/MW. The two technologies with the highest insurance value are the two dispatchable technologies left: nuclear power plants, with an insurance value of 3 790 €/MW, and hydro reservoirs, with an insurance value of 820 €/MW. The lower a dispatchable technology is in the merit order, the higher its insurance value regarding the inter-annual variability of VRE. The sensitivity analysis shows that the risk aversion coefficient only acts as a scaling factor for the results.

**Renewable uncertainty with a shock on gas supply**

Table 4 shows the insurance value of solar PV, wind, and the different dispatchable technologies of the power system from a cost perspective when VRE uncertainty and a shock on gas supply are considered.

| Technology | Insurance value (€/MW) | | |
|---|---|---|---|
| | $\rho$ = 0.25 | $\rho$ = 0.3 | $\rho$ = 0.35 |
| Solar PV | 15 140 | 23 370 | 34 290 |
| Onshore wind | 29 500 | 45 570 | 66 790 |
| Nuclear | 124 930 | 192 770 | 282 650 |
| Hydro reservoirs | 53 730 | 82 780 | 121 120 |
| Daily pumped storage | 8 225 | 12 630 | 32 850 |
| Weekly pumped storage | 31 660 | 48 940 | 71 620 |
| Natural gas | 0 | 0 | 0 |
| Batteries | 940 | 1 440 | 3 720 |

Table 4: Insurance value from a cost perspective of the different technologies of the power system when VRE uncertainty and a shock on gas supply are considered

This time, wind capacities have a positive insurance value of 45 570 €/MW, which is higher than the solar PV insurance value set at 23 370 €/MW. VRE does help to stabilize the cost of the power system when considering the possibility of a gas crisis. In that case, the planner can rely efficiently on VRE to act as self-insurance. The difference between the two insurance values is explained by the difference in capacity factors between the two technologies but also by their timing of production. Wind capacities provide more electricity than PV in times of peak demand when gas-fired power plants are called.

The same pattern can be observed for dispatchable technologies as in the previous section. Because there are excess gas capacities in this capacity mix, their insurance value is set to 0 €/MW. The insurance value of storage technologies is ranked according to their storage capacities: first, weekly pumped storage, with an insurance value of 48 940 €/MW; then daily pumped storage, with an insurance value of 12 630 €/MW; and finally, batteries, with an insurance value of 1 440 €/MW. Because nuclear plants have the highest capacity factors, their insurance value of 192 770 €/MW is the highest of the power system. They are followed by hydro reservoirs, with an insurance value of 82 780 €/MW.

Graphs 4 and 5 show the economic values of PV and wind capacities from a cost perspective when VRE uncertainty and a shock on gas supply are considered, as well as their optimal levels of penetration in the capacity mix.

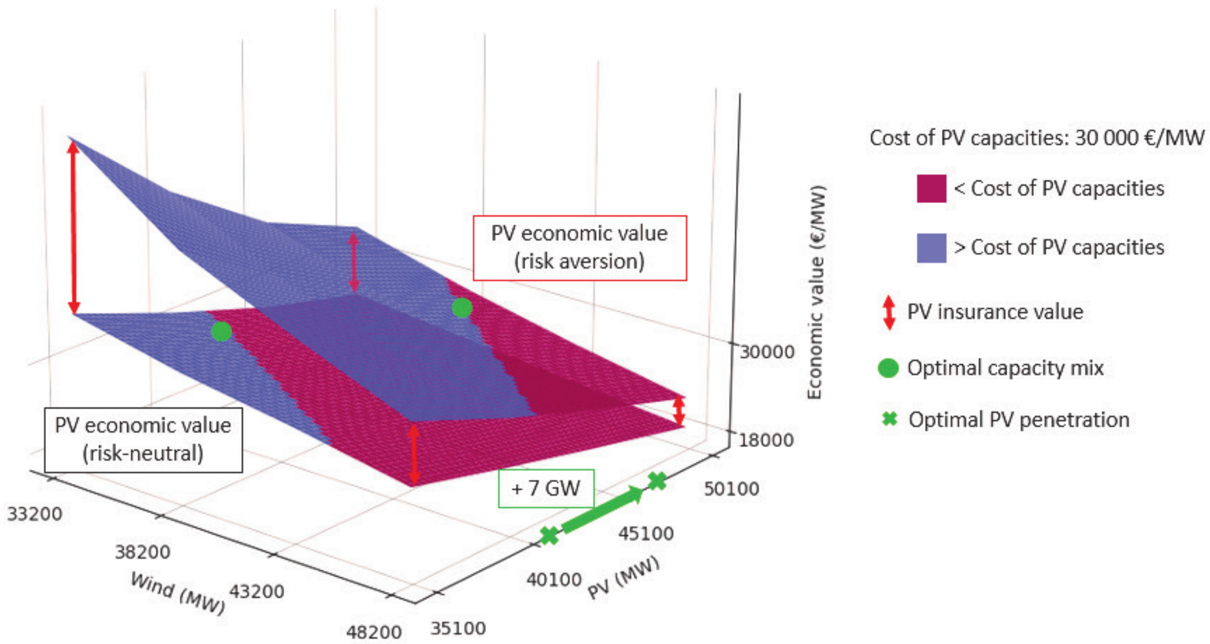


Figure 4: PV economic value from the cost perspective when VRE uncertainty and a shock on gas supply are considered (source: author's proposition)

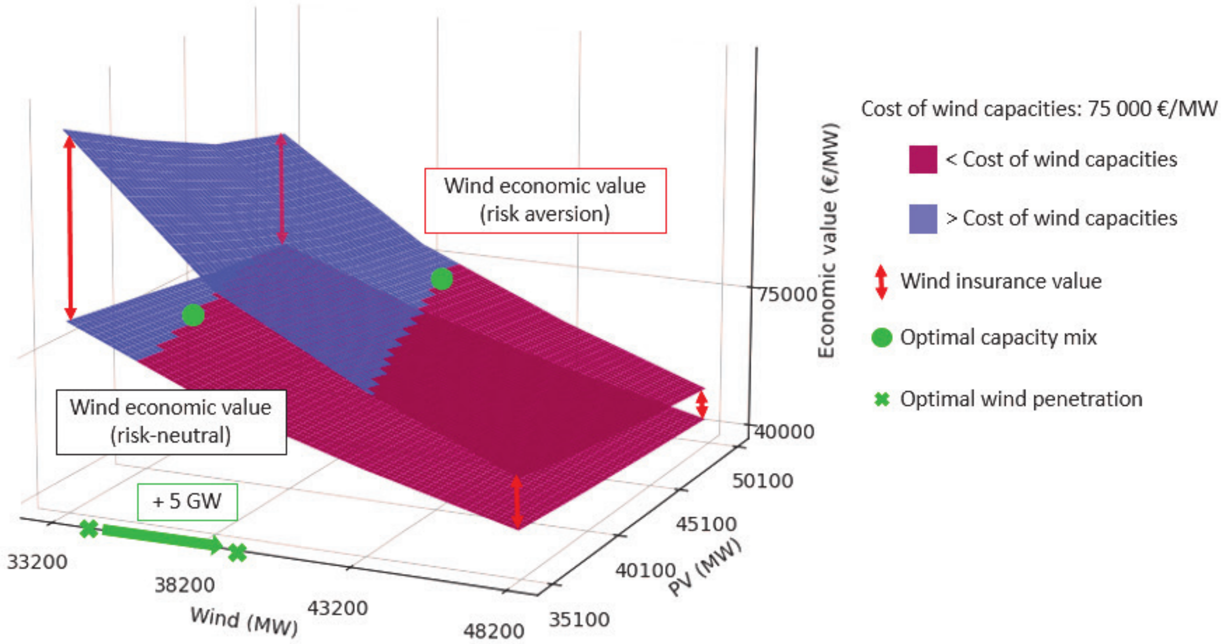


Figure 5: Wind economic value from the cost perspective when VRE uncertainty and a shock on gas supply are considered (source: author's proposition)

PV and wind provide a positive but decreasing insurance value for society. The optimal level of VRE penetration is identified when the cost of a capacity is equal to its value. At this level of collective risk aversion, additional funding of 7 GW of PV and 5 GW of wind capacities through State intervention is justified. In anticipation of a potential supply shock, it is relevant for public authorities to switch from the position of last-resort actors to the position of first-resort players to help renewable development.

Figure 6 and figure 7 present a sensitivity analysis on the risk aversion coefficient to evaluate how PV and wind insurance values are sensitive to a change in risk preferences. The baseline coefficient of 0.3 is framed by 0.25 and 0.35. PV and wind penetrations in the reference capacity mix are studied separately.

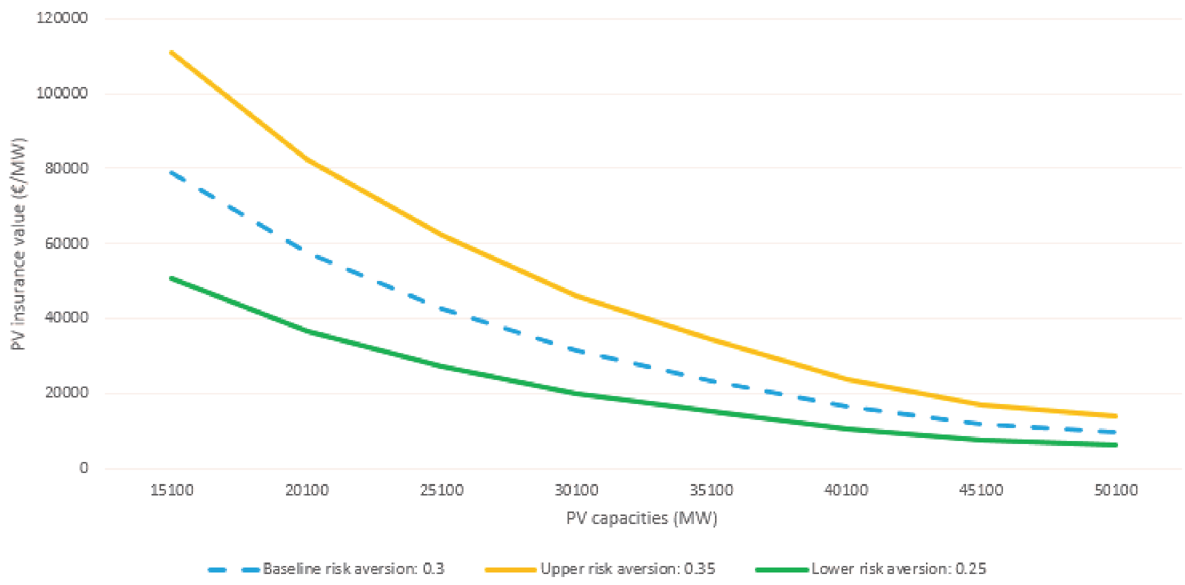


Figure 6: Sensitivity analysis of PV insurance value from the cost perspective (source: author's proposition)

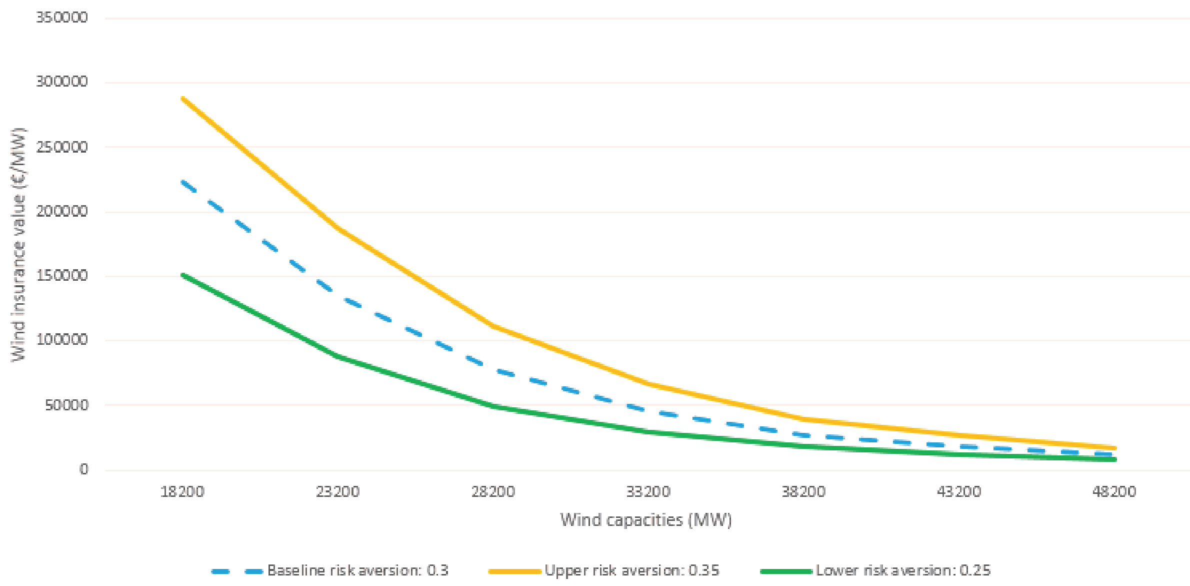


Figure 7: Sensitivity analysis of wind insurance value from the cost perspective (source: author's proposition)

These graphs show that the risk aversion coefficient only acts as a scaling factor. The shape of the curves representing the evolution of the insurance value is left unchanged. In the early phases of VRE penetration, a higher risk aversion leads to a higher insurance value, and a lower risk aversion leads to a lower insurance value. In every case, the insurance value decreases and tends to zero with VRE development.

#### 4.2.2. Price perspective

In the representation of the electricity market proposed by GenX, the offer curve is a staircase function. As a result, the derivative function of the risk premium regarding the penetration of VRE is undefined over the interval of interest. Before assessing the insurance value from a price perspective, we need, when available, an adequate differentiable approximation of the risk premium function.

This time, the consumer's risk aversion coefficient is set at 0.005. Similar values can be found in Bichuch et al. (2023). Sensitivity analyses are performed throughout the section to test how the level of risk aversion impacts the results.

### Renewable uncertainty only

Figure 8 shows the evolution of the consumer's risk premium with PV and wind penetration when only VRE uncertainty is considered.

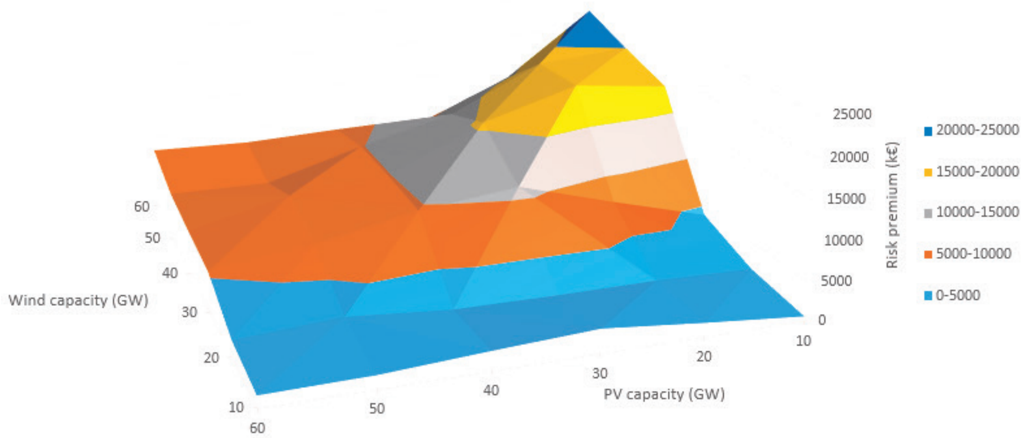


Figure 8: Consumer's risk premium due to VRE uncertainty (source: author's proposition)

Below 20 GW of solar and wind penetration, the risk premium increases with VRE penetration. The associated insurance value of PV and wind is, therefore, negative. After this threshold, the evolution of the risk premium is not monotonic, highlighting VRE technologies' role in mitigating their own uncertainties. Notably, PV acts convincingly as an insurance against wind inter-annual variability. However, VRE penetration is overall associated with an increase in the risk premium as its value for PV and wind penetration below 20 GW is lower than its value for PV and wind penetration above 30 GW.

Without the possibility to trade risk, the penetration of VRE penalizes the risk-averse consumer, and the socially optimal capacity mix regarding the expected utility of market participants contains less VRE than the one optimal when consumers are risk-neutral. Buying full financial insurance for electricity prices allows consumers to disregard risks. In that case, the socially optimal capacity mix equates to the optimal one for risk-neutral consumers, which contain a higher share of VRE. Therefore, those graphs highlight the need for long-term contracts to assist VRE deployment.

**Renewable uncertainty with a shock on gas supply**

Figure 9 displays the evolution of the risk premium with PV and wind penetration when VRE uncertainty and a shock on gas supply are considered.

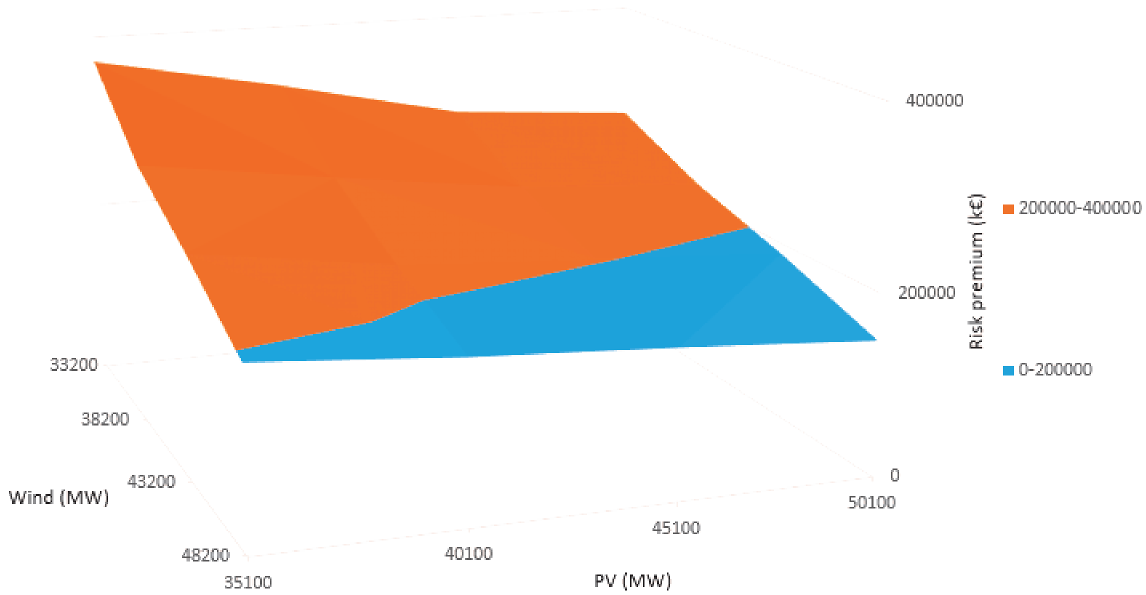


Figure 9: Consumer's risk premium due to VRE uncertainty and a shock on gas supply (source: author's proposition)

This graph shows that the risk premium can be approximated by a plan for the levels of VRE penetration under study. Constant insurance values can be deducted from the variation of the risk premium due to PV and wind penetration in the reference capacity mix. This yields an insurance value of 7 000 €/MW for PV and 12 000 €/MW for wind. Figures 10 and 11 show the economic value of PV and wind capacities from a price perspective when VRE uncertainty and a shock on gas supply are considered, as well as their optimal penetration levels in the capacity mix.

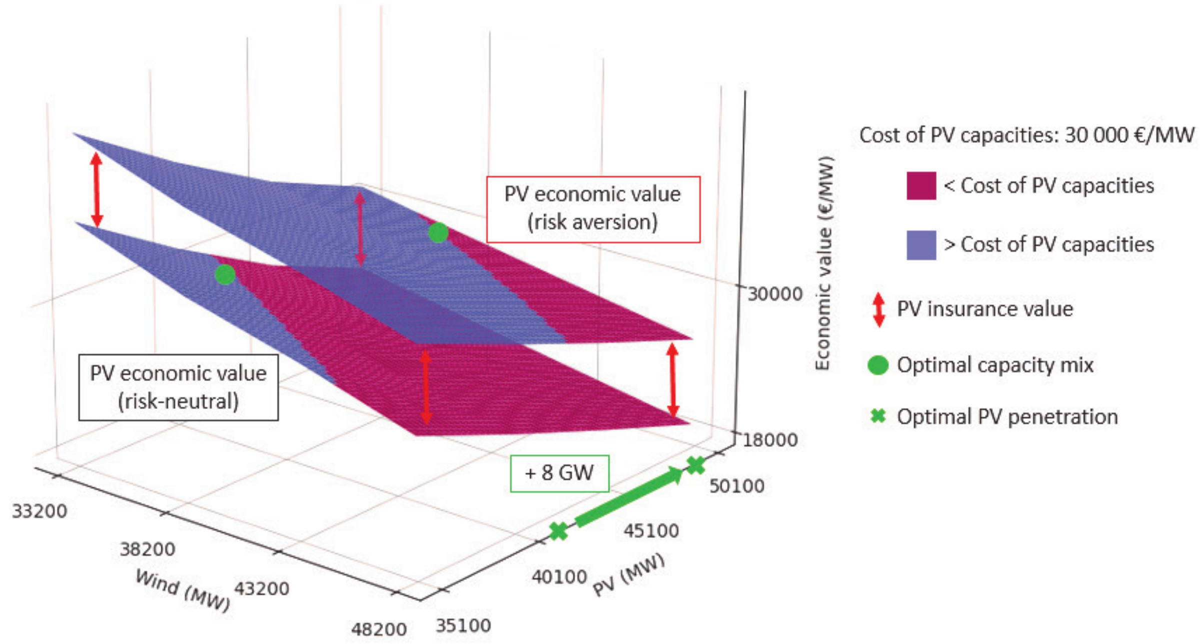


Figure 10: PV economic value from the price perspective when VRE uncertainty and a shock on gas supply are considered (source: author's proposition)

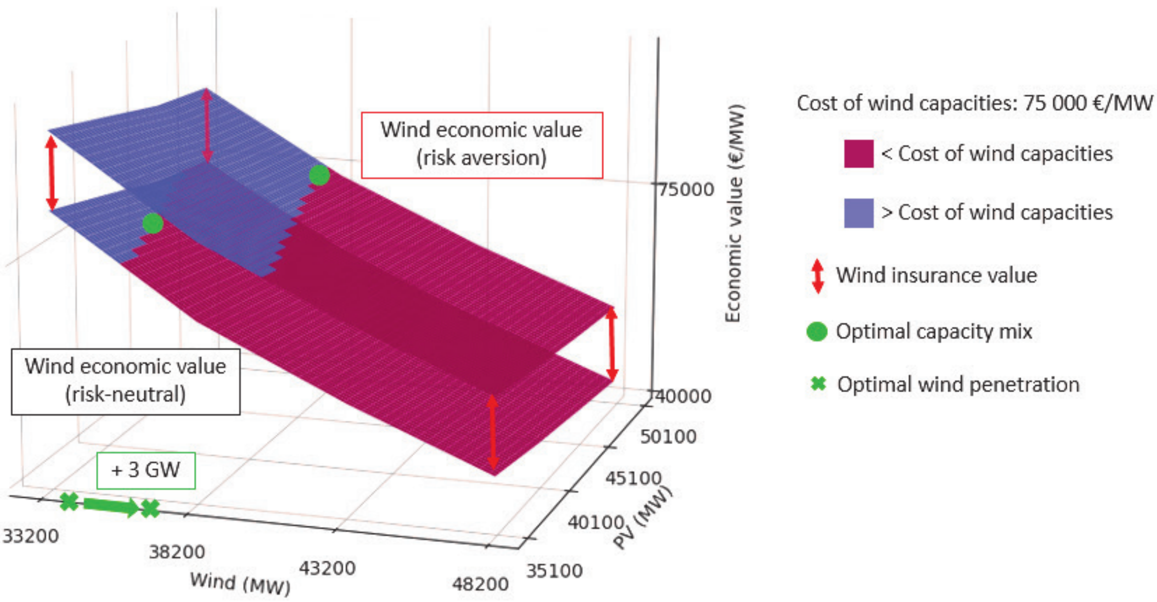


Figure 11: Wind economic value from the price perspective when VRE uncertainty and a shock on gas supply are considered (source: author's proposition)

In this framework, VRE has a positive insurance value which justifies an increased development of 8 GW of solar capacities and 3 GW of wind capacities. In other words, VRE increases the price stability of the power system, giving incentives for a planner concerned about the expected utility of market participants to push VRE development compared to the risk-neutral case.

Figure 12 and figure 13 highlight how the risk premium, and therefore the insurance value, evolves with risk preferences. PV and wind penetrations in the reference capacity mix are studied separately. Their insurance values can be directly read from the slopes of the curves appearing respectively in figure 12 and figure 13. The baseline risk aversion coefficient of 0.005 is bounded by 0.004 and 0.006.

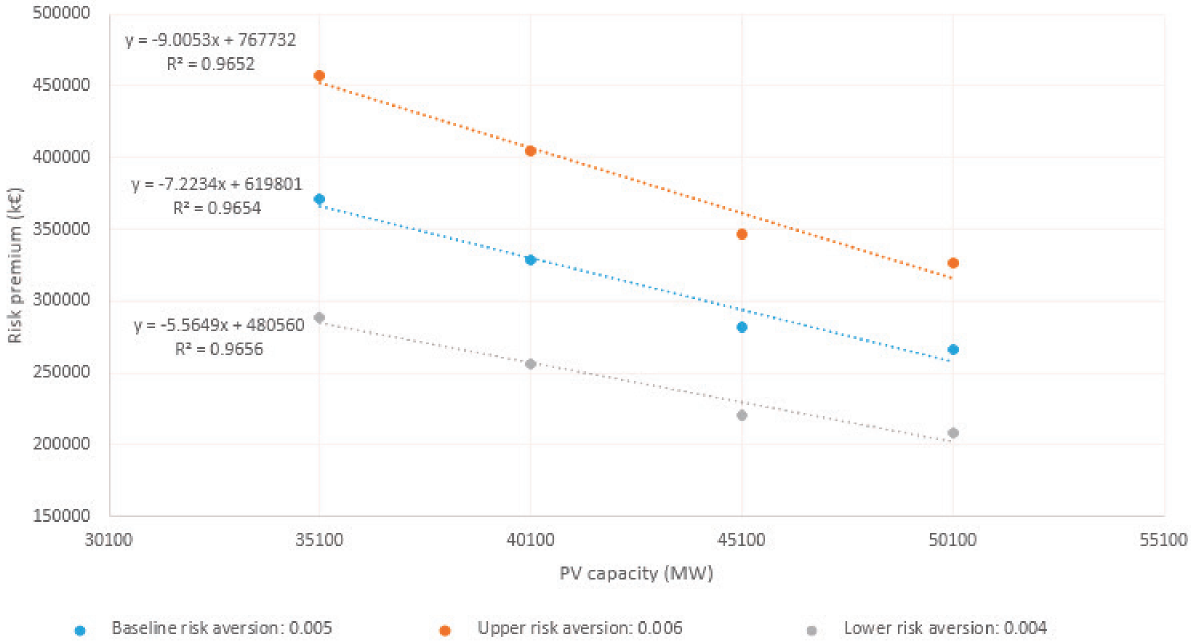


Figure 12: Sensitivity analysis of PV insurance value from the price perspective (source: author's proposition)

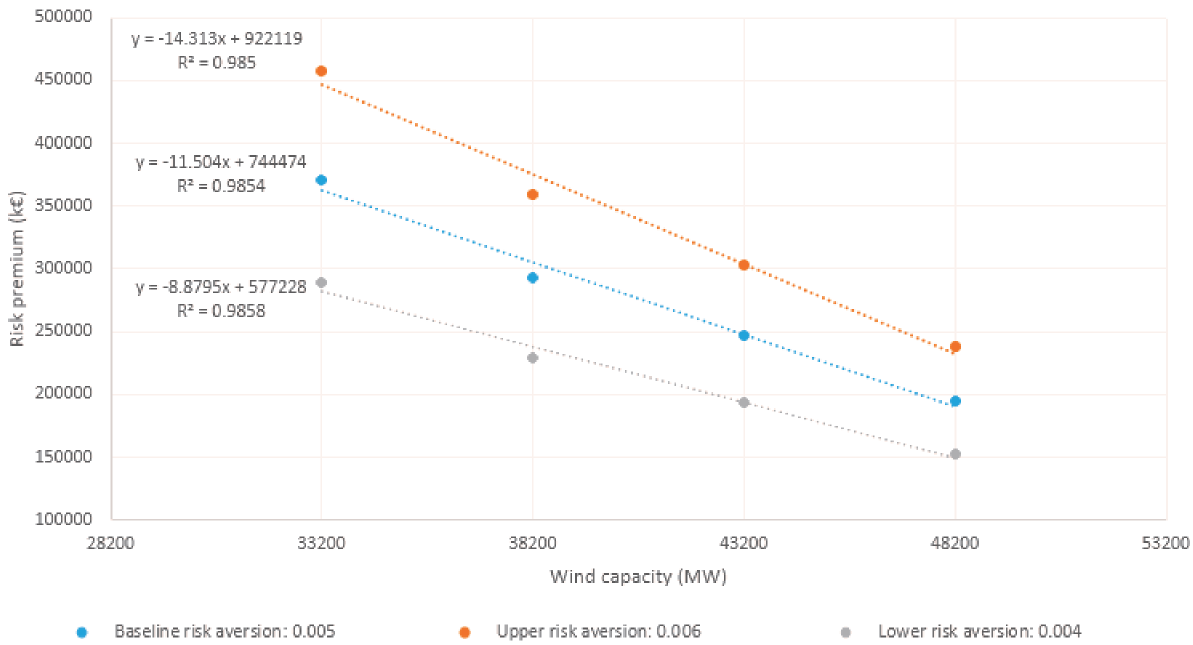


Figure 13: Sensitivity analysis of wind insurance value from the price perspective (source: author's proposition)

The shape of the risk premium curve remains the same for the different levels of risk aversion tested. A higher (lower) risk aversion leads to higher (lower) insurance value. Once again, the sensitivity analysis shows that the risk aversion coefficient only acts as a scaling factor.

### 4.3. Discussion

A set of core assumptions largely shape the numerical results obtained in this study. Firstly, the levels of risk aversion as well as the probability and size of the supply shock defined greatly the outcomes of the model. Moving forward, those hypotheses can be extended to include a broader range of scenarios in the analysis. However, by evaluating the insurance value of VRE with and without the possibility of a shock on gas, two extreme cases of subjective anticipations are studied. Although limited, it is enough to reveal essential qualitative features of the model and draw policy recommendations. Secondly, solar and wind uncertainties are modeled as independent variables and through extreme scenarios. A more detailed investigation should enhance the representation of solar and wind inter-annual variability and consider the correlation between the two sources of energy. Thirdly, import capacities are modeled through the addition of gas capacities. A better representation of interconnections can be considered in further research. Lastly, an interesting avenue for further research is the joint optimization of the different technologies in the capacity mix while considering the insurance value. Here, only PV and wind capacities are jointly optimized, which is not an accurate representation of the evolution of the power sector. The numerical estimations presented in this paper can be extensively questioned. However, several key messages still emerge from this study.

The results of section 4.2.1 and section 4.2.2 highlight the differences between the cost perspective and the price perspective. In the latter, the risk aversion coefficient can be significantly lower, but VRE can still have a meaningful insurance value. As a result, depending on the policy objectives, different optimal capacity mixes should be pursued. Risk-neutral preferences erase the difference between the two cases.

Also, as pointed out in the previous section, when VRE is the only source of uncertainty, their insurance value tends to be negative overall. However, when a shock on gas supply is possible, the insurance value turns positive. Therefore, there is a threshold of minimal assumptions beyond which VRE do not have a positive insurance value and do not act as self-insurance. An additional layer of VRE is justified to manage uncertainty only if the anticipated shock exceeds a certain size.

Finally, if VRE production is an objective source of uncertainty whose knowledge is shared among market participants, the same cannot be expected regarding the subjective probabilities of a gas supply shock. This means that VRE development can impede the expected utility of consumers if they do not share the same beliefs as the planner regarding a potential energy crisis. A planner willing to ensure the power system using VRE should also support long-term contracting in order not to penalize consumers in the process.

## V. CONCLUSION

Following the 2022 gas crisis, the EU energy security strategy is challenged. Domestic VRE production and import diversification are two pillars of the EU's answer to the situation. Investigating the interactions between the two levers is necessary to hedge collective risks optimally and find the best policy mix. However, VRE production has a distinctive characteristic relative to diversification: the resulting uncertainty can be objectively framed, bringing a particular degree of stability to the energy supply. Yet, those properties are not well-valued in traditional markets, and there is no guarantee that the hedging strategies of market participants based on their individual beliefs and risk preferences lead to optimal collective risk coverage.

In this paper, to discuss and evaluate the economic value of a power capacity in a context of uncertainty outside of market mechanisms, we use two collective utility functions, reflecting two extreme cases to represent collective risks. One translates the objective of cost stability. The other reflects the aim of price stability. This allows us to find the optimal capacity mix for the two policy objectives considered. In addition, we study how such collective utility functions relate to existing markets. We show that in both cases, the economic value of a generating unit is an addition of two components: the variation in expected surplus and the reduction of the risk premium. The first item is well captured in spot markets under marginal pricing. The second item, however, highlights the need for an additional structure to organize the power system. This theoretical framework adds to the literature on the GEP problem in multiple ways. Firstly, it proposes a new framework to guide collective actions in the power system, which adequately deals with interpersonal comparisons of utilities. Secondly, the decomposition of the economic value allows us to link the proposed optimization problems with the existing market structures to identify the necessary mix of market mechanisms and public interventions to reach the socially optimal capacity mix. Finally, we use this framework to formally show how power capacities can act as physical insurance and replace financial contracts to hedge risks.

A numerical application is performed to test the efficiency of using solar and wind as strategic tools to manage a gas supply shock for the two public policy objectives under study. Those energy sources have a positive insurance value regarding cost and price stability, leading to their increased penetration in the optimal capacity mix. Aside from environmental aspects, those results imply that there can be a new incentive for public support for the development of renewable energies. However, when a shock on gas supply is not anticipated, the insurance value can be negative because of the variability of those energies. Therefore, long-term contracts are also necessary to assist renewable development without penalizing consumers. The results displayed in this study are limited by several fundamental assumptions that can be challenged in further studies, namely the type and level of risk aversion, as well as the beliefs regarding a potential supply shock.

However, this insurance perspective seems to us to have a more general scope, for example, to consider the interest of the development of electric vehicles, in a context of instability in the oil market and, more generally, in an environment where security of supply is an issue, which should encourage to delve deeper into the initial intuition that led to this work.

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# APPENDICES

## A. DEMONSTRATION - ECONOMIC VALUE OF A CAPACITY: A COST PERSPECTIVE

Let's consider that $n \in \mathbb{N}$ states of the world are possible with a fixed probability of occurrence $(\alpha_i)_{1 \leq i \leq n}$. Each state of the world corresponds to a set of annual inputs for the power system (capacity availability, energy prices, demand, etc.). In return, the deterministic operation of the electricity market over a year fixes consumer surplus and producer surplus. Let's define social surplus $SS$ (in euro) as the sum of consumer and producer surplus.

In the cost perspective, we consider that the planner of the electric system is concerned with fixed costs $FC$ (in euro) and the social surplus that occurs in the electricity market in the different states of the world. The lottery that the planner faces can be expressed as follows:

$$SS - FC = (SS_i - FC \ ; \ \alpha_i)_{1 \leq i \leq n} \tag{A.1}$$

The preferences of the planner over lotteries can be expressed by the following vNM expected utility function:

$$U : SS - FC \longmapsto E[u(SS - FC)] \tag{A.2}$$

Here, $E$ is the expectancy operator. Assuming that the planner displays constant absolute risk aversion through a coefficient $\rho$ (in euro$^{-1}$), $u$ is defined as follows:

$$u : x \in \mathbb{R} \longmapsto -e^{-\rho x} \qquad \text{with } \rho > 0 \tag{A.3}$$

Now, let's evaluate the maximum willingness to pay $mWTP$ (in euro) of the planner for an additional capacity $\Delta$ (in MW) of a particular technology. The lottery regarding the social surplus that occurs in the electricity market with the new capacity is denoted $SS'$. The maximum willingness to pay for $\Delta$ satisfies the following equation:

$$\sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i - FC)} = \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS'_i - FC - mWTP(\Delta))} \tag{A.4}$$

Because $FC$ and $mWTP(\Delta)$ are paid in every state of the world, we have:

$$\begin{aligned}
& \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i)} = e^{\rho mWTP(\Delta)} \sum_{i=1}^{n} -\alpha_i e^{-\rho SS'_i} \\
\implies \quad & U(SS) = e^{\rho mWTP(\Delta)} U(SS') \\
\implies \quad & e^{\rho mWTP(\Delta)} = \frac{-U(SS)}{-U(SS')}
\end{aligned}$$

$$\implies \quad mWTP(\Delta) = \frac{1}{\rho}(ln(-U(SS)) - ln(-U(SS'))) \tag{A.5}$$

Also, the risk premium $\pi$ (in euro) of the planner is defined by the following equation:

$$\begin{aligned}
& u(E[SS] - FC - \pi) = U(SS - FC) \\
\implies \quad & -e^{-\rho(E[SS]-\pi)} = U(SS) \\
\implies \quad & \rho\pi - \rho E[SS] = ln(-U(SS))
\end{aligned}$$

$$\implies \quad \pi = \frac{1}{\rho} ln(-U(SS)) + E[SS] \tag{A.6}$$

Let's consider that the technology under study is already in the capacity mix at a level of $C$ MW. By definition, its insurance value I(C) (in euro/MW) is given by:

$$I(C) = -\frac{d\pi}{dC}$$

$$\implies \quad I(C) = -\frac{1}{\rho}\frac{dln(-U(SS))}{dC} - \frac{dE[SS]}{dC} \tag{A.7}$$

By definition of the economic value $V(C)$ (in euro/MW), we also have:

$$V(C) = \lim_{\Delta \to 0} \frac{mWTP(\Delta)}{\Delta} \tag{A.8}$$

Using (A.5), by the definition of a derivative function, we have:

$$V(C) = -\frac{1}{\rho}\frac{dln(-U(SS))}{dC} \tag{A.9}$$

Using (A.7), we get:

$$V(C) = \frac{dE[SS]}{dC} + I(C)$$

## B. DEMONSTRATION - ECONOMIC VALUE OF A CAPACITY: A PRICE PERSPECTIVE

Let's keep the same framework and notations to represent uncertainty as in the previous section.

Let's assume that:

(I) Consumers' preferences for different power system organizations can be described ex-ante by the expected value of a vNM utility function taking consumer surplus $CS$ (in euro) as an argument:

$$U_c : CS \longmapsto E[u_c(CS)] \tag{B.1}$$

with,

$$u_c : x \in \mathbb{R} \longmapsto -e^{-\rho_c x} \qquad \text{with } \rho_c > 0 \tag{B.2}$$

(II) Firms are driven by expected profits, the difference between producer surplus $PS$ (in euro) and fixed costs $FC$ (in euro), which can be interpreted as a utility function:

$$U_p : (PS, FC) \longmapsto E[u(PS - FC)] \tag{B.3}$$

with,

$$u_p : x \in \mathbb{R}^2 \longmapsto x \tag{B.4}$$

(III) Social preferences satisfy the vNM axioms over the set of social lotteries,

(IV) If consumers and producers prefer configuration A of the power system to configuration B or one is indifferent between the two, but the other prefers A to B, then society prefers A to B.

Under those assumptions, the social aggregation theorem of Harsanyi states that society's preferences can be represented by a function linear in the expected utility of agents (Harsanyi, 1955; Harsanyi, 1977). Therefore, the following collective utility function can guide collective actions:

$$CUF = K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} + K_p \sum_{i=1}^{n} \alpha_i (PS_i - CF) \qquad \text{with } \rho_c, K_c, K_p > 0 \tag{B.5}$$

First, let's define the risk premium $\pi_c$ (in euro) of consumers:

$$u_c(E[CS] - \pi_c) = U_c(CS) \tag{B.6}$$

Similarly to the previous section, we get:

$$\pi_c = \frac{1}{\rho_c} ln(-U_c(CS)) + E[CS] \tag{B.7}$$

Using the collective utility function defined in (B.5), let's evaluate the maximum willingness to pay $mWTP$ (in euro) of the consumer for an additional capacity $\Delta$ (in MW) of a particular technology. By definition, we have:

$$\begin{aligned} & K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} + K_p \sum_{i=1}^{n} \alpha_i (PS_i - CF) \\ = {} & K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c (CS'_i - mWTP(\Delta))} + K_p \sum_{i=1}^{n} \alpha_i (PS'_i - CF) \end{aligned} \tag{B.8}$$

Therefore:

$$\begin{aligned} & K_c U_c(CS) + K_p U_p(PS) = e^{\rho_c mWTP(\Delta)} K_c U_c(CS') + K_p U_p(PS') \\ \implies \quad & e^{\rho_c mWTP(\Delta)} K_c U_c(CS') = K_c U_c(CS) + K_p (U_p(PS) - U_p(PS')) \\ \implies \quad & e^{\rho_c mWTP(\Delta)} = \frac{1}{K_c U_c(CS')} \left( K_c U_c(CS) + K_p (U_p(PS) - U_p(PS')) \right) \\ \implies \quad & e^{\rho_c mWTP(\Delta)} = \frac{U_c(CS)}{U_c(CS')} \left( 1 + \frac{1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS) - U_p(PS')) \right) \end{aligned}$$

The maximum willingness to pay for a marginal capacity can be directly expressed:

$$\begin{aligned} & mWTP(\Delta) = \frac{1}{\rho_c} ln \left( \frac{U_c(CS)}{U_c(CS')} \left( 1 + \frac{1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS) - U_p(PS')) \right) \right) \\ \implies \quad & mWTP(\Delta) = \frac{1}{\rho_c} ln \left( \frac{-U_c(CS)}{-U_c(CS')} \left( 1 + \frac{-1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS') - U_p(PS)) \right) \right) \\ \implies \quad & mWTP(\Delta) = \frac{1}{\rho_c} \left( ln(\frac{-U_c(CS)}{-U_c(CS')}) + ln \left( 1 + \frac{-1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS') - U_p(PS)) \right) \right) \end{aligned} \tag{B.9}$$

By definition of the economic value $V$, we have:

$$V = \lim_{\Delta \to 0} \frac{1}{\rho_c} \left( \frac{ln(-U_c(CS)) - ln(-U_c(CS'))}{\Delta} + \frac{ln\left(1 + \frac{-1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS') - U_p(PS))\right)}{\Delta} \right) \tag{B.10}$$

By the definition of a derivative function, let's notice that:

$$\lim_{\Delta \to 0} \left( \frac{1}{\rho_c} \frac{ln(-U_c(CS)) - ln(-U_c(CS'))}{\Delta} \right) = -\frac{1}{\rho_c} \frac{dln(-U_c(CS))}{dC} \tag{B.11}$$

Derivating (B.7) and using the definition of the insurance value, we get:

$$\lim_{\Delta \to 0} \left( \frac{1}{\rho_c} \frac{ln(-U_c(CS)) - ln(-U_c(CS'))}{\Delta} \right) = \frac{dE[CS]}{dC} + I(C) \tag{B.12}$$

Also, we have:

$$\lim_{\Delta \to 0} \frac{-1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS') - U_p(PS)) = 0 \tag{B.13}$$

Using the properties of the natural logarithm, this gives:

$$\lim_{\Delta \to 0} \frac{ln\left(1 + \frac{-1}{U_c(CS)} \frac{K_p}{K_c} (U_p(PS') - U_p(PS))\right)}{\Delta} = \frac{-1}{U_c(CS)} \frac{K_p}{K_c} \frac{dU_p(PS)}{dC} \tag{B.14}$$

Because (B.10) expresses the limit of a function, defined as a sum of two convergent subfunctions in the point of interest, we get:

$$V(C) = \frac{dE[CS]}{dC} + I(C) + \frac{-1}{\rho_c U_c(CS)} \frac{K_p}{K_c} \frac{dU_p(PS)}{dC} \tag{B.15}$$

The coefficients $K_c$ and $K_p$ translate the ethical preferences of society regarding consumers and producers. A fair assumption would be for society to be indifferent between giving one euro in every state of the world to consumers or producers. This condition yields the following equation:

$$\begin{aligned} & K_c U_c(CS+1) + K_p U_p(PS) = K_c U_c(CS) + K_p U_p(PS+1) \\ \implies \quad & K_c U_c(CS) - K_c U_c(CS+1) = K_p U_p(PS) - K_p U_p(PS+1) \end{aligned}$$

$$\implies \quad \frac{K_p}{K_c} = \frac{U_c(CS) - U_c(CS+1)}{U_p(PS) - U_p(PS+1)} \tag{B.16}$$

Assuming that producers are risk neutral, we get:

$$U_p(PS) - U_p(PS+1) = \sum_{i=1}^{n} \alpha_i PS_i - \sum_{i=1}^{n} \alpha_i (PS_i + 1)$$

$$\implies \quad U_p(PS) - U_p(PS+1) = -1 \tag{B.17}$$

Also,

$$\begin{aligned}
& U_c(CS) - U_c(CS+1) = \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} - \sum_{i=1}^{n} -\alpha_i e^{-\rho_c (CS_i+1)} \\
\implies \quad & U_c(CS) - U_c(CS+1) = \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} - e^{-\rho_c} \sum_{i=1}^{n} -\alpha_i e^{-\rho_c CS_i} \\
\implies \quad & U_c(CS) - U_c(CS+1) = (1 - e^{-\rho_c}) U_c(CS)
\end{aligned} \tag{B.18}$$

For small values of $\rho_c$, the Taylor's series expansion of the function exponential around zero yields the following approximation:

$$U_c(CS) - U_c(CS+1) = \rho_c U_c(CS) \tag{B.19}$$

Using (B.16), (B.17) and (B.19), we get:

$$\frac{K_p}{K_c} = -\rho_c U_c(CS) \tag{B.20}$$

Injecting this result in (B.15), we have:

$$\begin{aligned}
& V(C) = \frac{dE[CS]}{dC} + I(C) + \frac{dU_p(PS)}{dC} \\
\implies \quad & V(C) = \frac{dE[CS]}{dC} + I(C) + \frac{dE[PS]}{dC} \\
\implies \quad & V(C) = \frac{dE[SS]}{dC} + I(C)
\end{aligned}$$

## C. DEMONSTRATION - ECONOMIC VALUE OF AN INSURANCE CONTRACT: A COST PERSPECTIVE

Following the framework of section 3.2.44., let's consider a financial contract $F$ defined by:

$$F = q(X - E[X]) \qquad \text{with } 0 \leq q \leq 1 \tag{C.1}$$

Here, $X$ is a random variable (in euro) representing the risk covered by the financial contract. For example, X can cover the cost of gas in the power system. $E[X]$ is the expectation operator over the probabilities of $X$. $q$ is the portion of the risk insured (no unit). When $q = 0$, no risk is insured, and when $q = 1$, the risk is fully insured. Continuing the gas example, if the planner is fully insured, he gets a payoff equal to the difference between his total gas bill at the end of the year and its average value. Here, no other additional cost for the buyer is considered (transaction cost, insurer profits, etc.).

The integration of $F$ to the cost perspective leads to the optimization of the following function:

$$\sum_{i=1}^{n} -\alpha_i e^{-\rho((SS_i - CF)+q(X_i - E[X]))} \qquad \text{with } \rho > 0 \tag{C.2}$$

The risk premium $\pi$ (in euro) of the planner satisfies:

$$\begin{aligned}
& u(E[SS + F - CF] - \pi) = U(SS - CF + F) \\
\implies \quad & -e^{-\rho(E[SS]+E[F]-\pi)} = U(SS + F) \\
\implies \quad & -e^{-\rho(E[SS]-\pi)} = U(SS + F) \\
\implies \quad & \rho\pi - \rho E[SS] = ln(-U(SS + F)) \\
\implies \quad & \pi = \frac{1}{\rho} ln(-U(SS + F)) + E[SS]
\end{aligned}$$

The insurance value of $F$ regarding $q$ is defined by:

$$\begin{aligned}
& I_F(q) = -\frac{d\pi}{dq} \\
\implies \quad & I_F(q) = -\left(\frac{1}{\rho}\frac{dln(-U(SS + F(q)))}{dq} + \frac{dE[SS]}{dq}\right)
\end{aligned}$$

$$\implies \quad I_F(q) = -\frac{1}{\rho}\frac{dln(-U(SS + F(q)))}{dq} \tag{C.3}$$

The maximum willingness to pay for a marginal addition of risk coverage $\Delta_q$ is given by:

$$\begin{aligned}
& \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i+F_i(q))} = \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i+F_i(q+\Delta_q)-mWTP(\Delta_q))} \\
\implies & \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i+F_i(q))} = e^{\rho mWTP(\Delta_q)} \sum_{i=1}^{n} -\alpha_i e^{-\rho(SS_i+F_i(q+\Delta_q))} \\
\implies & mWTP(\Delta_q) = \frac{1}{\rho}(ln(\sum_{i=1}^{n} \alpha_i e^{-\rho(SS_i+F_i(q))}) - ln(\sum_{i=1}^{n} \alpha_i e^{-\rho(SS_i+F_i(q+\Delta_q))})) \\
\implies & mWTP(\Delta_q) = \frac{1}{\rho}(ln(-U(SS+F(q))) - ln(-U(SS+F(q+\Delta_q))))
\end{aligned}$$

The economic value of the contract $F(q)$ is:

$$\begin{aligned}
& V_F(q) = \lim_{\Delta_q \to 0} \frac{mWTP(\Delta_q)}{\Delta_q} \\
\implies & V_F(q) = \lim_{\Delta_q \to 0} \frac{\frac{-1}{\rho}(ln(-U(SS+F(q+\Delta_q))) - ln(-U(SS+F(q))))}{\Delta_q}
\end{aligned}$$

Using (C.3), we get:

$$V_F(q) = I_F(q)$$

## D. DEMONSTRATION - ECONOMIC VALUE OF AN INSURANCE CONTRACT: A PRICE PERSPECTIVE

The integration of $F$ to the price perspective leads to the optimization of the following function:

$$K_c \sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i(q))} + K_p \sum_{i=1}^{n} \alpha_i(PS_i - CF) \qquad \text{with } \rho_c, K_c, K_p > 0 \tag{D.1}$$

Similarly to the previous section, the consumer's risk premium $\pi_c$ (in euro) is given by:

$$
\begin{aligned}
& u(E[CS+F]-\pi_c) = U(CS+F) \\
\implies & -e^{-\rho_c(E[CS]+E[F]-\pi_c)} = U(CS+F) \\
\implies & -e^{-\rho_c(E[CS]-\pi_c)} = U(CS+F) \\
\implies & \rho_c\pi_c - \rho_c E[CS] = ln(-U(CS+F)) \\
\implies & \pi_c = \frac{1}{\rho_c} ln(-U(CS+F)) + E[CS]
\end{aligned}
$$

By definition of the insurance value, we have:

$$
\begin{aligned}
& I_F(q) = -\frac{d\pi_c}{dq} \\
\implies & I_F(q) = -(\frac{1}{\rho_c}\frac{dln(-U(CS+F(q)))}{dq} + \frac{dE[CS]}{dq})
\end{aligned}
$$

$$
\implies \quad I_F(q) = -\frac{1}{\rho_c}\frac{dln(-U(CS+F(q)))}{dq} \tag{D.2}
$$

The maximum willingness to pay for a marginal addition of risk coverage $\Delta_q$ satisfies:

$$
\begin{aligned}
& K_c\sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i(q))} + K_p(\sum_{i=1}^{n}\alpha_i PS_i - CF) \\
= & K_c\sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i(q+\Delta_q)-mWTP(\Delta_q))} + K_p(\sum_{i=1}^{n}\alpha_i PS_i - CF)
\end{aligned}
$$

Therefore:

$$
\begin{aligned}
& K_c\sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i(q))} = K_c\sum_{i=1}^{n} -\alpha_i e^{-\rho_c(CS_i+F_i(q+\Delta_q)-mWTP(\Delta_q))} \\
\implies & e^{\rho_c mWTP(\Delta_q)} = \frac{K_c\sum_{i=1}^{n}\alpha_i e^{-\rho_c(CS_i+F_i(q))}}{K_c\sum_{i=1}^{n}\alpha_i e^{-\rho_c(CS_i+F_i(q+\Delta_q))}}
\end{aligned} \tag{D.3}
$$

This yields:

$$
\begin{aligned}
& mWTP(\Delta_q) = \frac{1}{\rho_c}(ln(\sum_{i=1}^{n}\alpha_i e^{-\rho_c(CS_i+F_i(q))}) - ln(\sum_{i=1}^{n}\alpha_i e^{-\rho_c(CS_i+F_i(q+\Delta_q))})) \\
\implies & mWTP(\Delta_q) = \frac{1}{\rho_c}(ln(-U_c(CS+F(q))) - ln(-U_c(CS+F(q+\Delta_q)))) \\
\implies & mWTP(\Delta_q) = \frac{-1}{\rho_c}(ln(-U_c(CS+F(q+\Delta_q))) - ln(-U_c(CS+F(q))))
\end{aligned}
$$

The economic value of the contract $F(q)$ is:

$$
\begin{aligned}
& V_F(q) = \lim_{\Delta_q \to 0} \frac{mWTP(\Delta_q)}{\Delta_q} \\
\implies \quad & V_F(q) = \lim_{\Delta_q \to 0} \frac{\frac{-1}{\rho_c}(ln(-U(CS + F(q + \Delta_q))) - ln(-U(CS + F(q))))}{\Delta_q}
\end{aligned}
\tag{D.4}
$$

Using (D.2), we get:

$$
V_F(q) = I_F(q) \tag{D.5}
$$