CHAIRE EUROPEAN ELECTRICITY MARKETS/WORKING PAPER #51

Decarbonizing the Electricity Sector Efficiently Requires a Change of Market-Design

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DECARBONIZING THE ELECTRICITY SECTOR EFFICIENTLY REQUIRES A CHANGE OF MARKET-DESIGN

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November 2021

Abstract

A 2050 carbon neutrality target is bound to become mandatory in the European Union. Since most low-carbon generation technologies have mainly fixed costs, and low or zero variable costs, wholesale electricity prices will be low most of the time, set by those variable costs, and high only during periods of scarcity. Thus, reaching carbon neutrality in 2050 (or before) in the electricity sector will lead to more volatile electricity prices. In an Energy-Only market, this implies that power plants' gross margins will become more volatile. Using French load datas, we show that this increase in volatility yields a much higher cost of capital for generation capacity investment, with perfect competition. As a consequence, security of supply standards will not be met, and the costs of electricity for consumers will increase significantly. We also show that implementing long-term contracts allows to prevent this increase in financing cost. We conclude that a change of market design will be required to enable an efficient decarbonization of the electricity sector.

Keywords: generation adequacy; decarbonization; electricity market design; cost of capital.

Acknowledgments: This paper has benefited from the support of the Chaire European Electricity Markets (CEEM) of the Université Paris Dauphine-PSL under the aegis of the Foundation Paris-Dauphine, supported by RTE, EDF, EPEX Spot and Total Energies. The views and opinions expressed in this paper are those of the authors and do not necessarily reflect those of the partners of the CEEM

The autor is indebted to Thomas-Olivier Léautier, Claude Crampes, Bert Willems and Stefan Ambec, and participants of EDF / Toulouse School of Economics-IDEI regular seminar for valuable comments. All errors and views are his own.

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I. INTRODUCTION

A 2050 carbon neutrality target has become part of law in France and in the United Kingdom. With the European Green Deal currently in discussion, it is highly probable it will also become mandatory at the European Union level. Most low-carbon generation technologies have mainly fixed costs, and low or zero variable costs. Thus, wholesale electricity prices will be low most of the time, set by those variable costs, and high only during periods of scarcity. As a consequence, reaching carbon neutrality in 2050 (or before) in the electricity sector will lead to more volatile electricity prices. In an Energy-Only market, this implies that power plants' gross margins will become more volatile (Joskow 2021).

It has been argued (Newbery 2016, Grubb and Newbery 2018, Newbery et al 2019) that this increase in volatility will yield higher financing costs, and requires the introduction of long-term contracts (FiT, CfD, hybrid RAB) in complement to the wholesale market in order to allow the massive investments needed in generation capacity. For example, the 2050 Long-Term Strategy of the European Union published in November 2018, estimates that, in order to respect the Paris Agreement commitment, at least 100 billion euros per year for the period 2021-2050 are needed in power plants investments. The UK Electricity Market Reform has been set in order to tackle this possible increase in financial risk linked to decarbonization, introducing a new kind of market design, a hybrid market (Finon, Keppler and Roques 2017). This evolution is seen as a correction of the market failure dubbed "missing markets" (Newbery 2016), i.e. the absence of derivatives markets allowing optimal risk-sharing between producers and consumers at an horizon higher than 3 years, when the lifetime of a power plant is much higher (at least 20 years) and the time to build at least 2 to 3 years. As explained by Newbery, the missing markets failure can be extended to the inability of capacity investors to hedge against future regulatory interventions that may negatively impact future profits. Climate energy policies make this risk very important for the electricity sector. This implies that long-term contracts should not be seen as subventions, but as means to implement a socially preferable outcome.

The purpose of this paper is to present some quantitative evidence in support of this view. Using 10 years of French load datas, we show that, in a perfect competition setting, the increase in volatility of gross margins in an Energy-Only market yields a much higher cost of capital for generation capacity investment at equilibrium. We use the Capital Asset Pricing Model to calculate asset betas, and show that they may become much higher than what is usually thought. The CAPM remains an important benchmark for companies and regulation agencies. As a consequence of higher financing costs, less investments than required will happen and security of supply standards will not be met. Furthermore, the costs of electricity for consumers will increase, raising social acceptance and industry competitivity issues. We show that implementing long-term contracts allows to prevent this increase in financing cost and enables a more efficient decarbonization of the electricity sector.

Section 2 reviews the literature. Section 3 describes the investment model and the way the discount rate is made endogenous to the perfect competition equilibrium, in coherence with the CAPM. Section 4 exposes the numerical results for an Energy-Only market, whether fossil fuel technologies are allowed or not. We show that decarbonizing the mix yields a much higher equilibrium cost of capital for low carbon technologies. In section 5, we analyse if a more flexible demand or the impact of storage can reverse the previous results and conclude that this is not the case. In section 6, we show that a CfD lowers the equilibrium cost of capital in a decarbonized electricity mix, thus allowing lower costs for consumers than in the Energy-Only case. Section 7 concludes.

II. LITTERATURE REVIEW

Some concerns about the ability of Energy-Only markets to correctly incentivize new capacity investments have begun to emerge at the beginning of the 2000s. At the time, the problem is limited to generation adequacy and the need for peak capacity. In the economic litterature, the main culprit is ”missing money” (Joskow 2008 & 2021, Cramton and Stoft 2005 & 2008). Prices are prevented from being high enough when capacity is scarce, thus taming the incentives to invest in peak power plants. Different mechanisms have been proposed to remedy this problem, capacity markets especially. More recently, another issue has been raised: financial risk may be too important for investors in order to get the required level of capacity, as can be defined by a Security of Supply (SoS) criterion, even in the absence of missing money. The problem is ”missing markets”: risk cannot be efficiently allocated through futures or contracts markets (Newbery, 2016), leading to underinvestment in capacity. A peaking power plant has very volatile revenues, since it may not be able to generate margins for many years, being the last plant in the merit order stack. This volatility translates into higher hurdle rates than usual, and less investment than thought when financial risk is not taken into account.

Some academic works (especially from Ehrenmann and Smeers, 2011a, 2011b, or de Maere, Ehrenmann and Smeers, 2016), and some policy studies (Artelys, 2016 and RTE, 2018) have analysed and quantified this phenomenon. RTE (the french TSO), in its 2018 impact assessment of the french capacity market, has argued that it is a welfare improving regulation, since it allows to lower the cost of peak capacity investment. The logic behind that assessment is stated very clearly by Sisternes and Parsons, 2016: ”Shifting the structure of profit to one in which the same total revenue is paid for capacity across a broader number of hours provides a better, more reliable signal to investors, which lowers the cost of capacity to society.” Thus, in the face of uncertainty, a well-designed capacity mechanism is preferable to an energy-only market design. Those works have used different risk criterias: an exponential utility function as a proxy for cost of capital impact (RTE, Petitet Finon Janssen 2017), Conditionnal Value at Risk (Ehrenmann Smeers 2011a, de Maere Ehrenmann Smeers 2016), semi-variance (Artelys, 2016). The common principle is that the risk criterion gives a deterministic equivalent of a random quantity, at a lower value than its expectation (discount), all the more that the risk measured is higher. The choice of the criterion is not neutral: semi-variance, by only taking into account losses, could be mistaken for the exercise of market-power through capacity underinvestment. CVar or the exponential utility do not take into account the possibility to partially hedge the risks through existing financial markets (Willems and Morbee, 2010 & 2013), as in the CAPM, which remains the theoritical basis underpinning cost of capital calculations, as performed by companies and regulators. The CAPM states that only a part of total risk is relevant to assess the investors' required rate of return from an asset, the systematic risk (the covariance with the market portfolio). In a previous work (Peluchon 2019), we have used the CAPM in an analysis of the different CRM designs discussed in the european context.

Net-zero targets in 2050 require to go beyond the question of generation adequacy. The electricity sector will need to be decarbonized even before 2050: for Europe in 2040 according to the Long Term Strategy published by the European Commission in 2018, and even 2035 in advanced economies for the International Energy Agency in its recently published Net Zero by 2050 study. Decarbonizing the other sectors will also require an increase in electricity generation in order to displace fossil fuels consumption (electrification). Those forecasts implie a huge level of investments in new power plants: at least 100 billion euros per year in Europe for the period 2021-2050, as estimated in the Long Term Strategy. Most of the new power plants will be variable renewables (solar and wind), which have zero variable costs. As a consequence, net revenues power plants earn in Energy-Only markets will be concentrated on fewer hours, those approaching scarcity conditions (Joskow 2021). Margins needed to cover fixed costs will be more volatile. But regulatory risk may also increase. We can quote Paul Joskow (2021): "the net revenues from investment in generation and storage will depend on getting the short run prices exactly right in a much small number of hours". This has led some to advocate the use of long-term contracts in complement to wholesale markets in order to induce the new investments needed (hybrid regime as named by Finon and Roques, 2017). In that context, the UK has introduced the Electricity Market Reform (EMR) through the Energy Act 2013. It set up a carbon price floor through a top-up tax to the EU-ETS price, and introduced Contract for Differences for low carbon technologies alongside a capacity market (capacity market payments are excluded for the technologies who benefit from CfDs). The rationale is stated in the White Paper from 2011 that has prepared this reform: a CfD is an explicit mean to lower the cost of capital for new investment, thus helping to lower the cost of decarbonization. Grubb and Newbery, 2018, have made a first attempt to analyse the EMR and its results so far. They seem to explain that lowering the risk for new capacity allows a lower WACC through an increased share of debt in the financing (see also CEPA, 2011). This has been criticised by Parsons, 2014b, on the basis that it ignored the principles of modern finance theory: in a Modigliani-Miller setting (with CAPM), the debt-equity ratio has no impact on the value of an asset, it just modifies the risk-reward repartition between shareholders and creditors. Parsons, 2012 and 2014a, defends the use of stochastic discount factors (SDFs) in order to get a rigorous view of the cost of capital of new generation capacity. What should be computed is asset-betas, that is betas before any consideration of financing structure. This the way followed in this work.

The integration of SDFs in generation capacity expansion models is precisely what has been done by Smeers and Ehrenmann, 2011b, in a very thorough article, corresponding to the total absence of electricity derivatives markets allowing risk-sharing between producers and consumers. Cochrane, 2005 is the reference for a very clear exposition of SDFs and their relations to CAPM and derivatives pricing. Electricity futures markets only exhibits sufficient liquidity for products whose maturities do not exceed 3 years. Since the time to build a power plant is greater, investment decisions are taken without being able to hedge future production, unless some form of long-term contract is signed with consumers (such as Power Purchase Agreements). In the European Union, such contracts are seen as potentially limiting competition and not encouraged by competition authorities. Furthermore, electricity retailers are exposed to the risk that consumers switch to another supplier, and are not allowed most of the time to prevent them from doing so. As a result they do not sign long-term supply agreements with producers. Incomplete markets is a market failure (missing markets) and, as Gollier, 2016, reminds us, with incomplete markets, social and private valuations are different, since all the mutually benefiting risk-sharing operations cannot be performed. As a consequence, competitive equilibrium outcomes may not be socially optimal, and some regulatory interventions may be welfare improving. The professional association of wind energy (Wind Europe, 2017) has made this point: fixed-price contracts allow a lower cost of capital and should not be seen as subventions. David, Le Breton and Morillon, 2011 contains a very interesting discussion of why the social optimum needs complete markets in the case of utilities, remarking in a footnote that this was even discussed as far back as 1953 by Marcel Boiteux in a workshop (following his seminal 1951 article). Explicit modelization of the risk-sharing between consumers and producers is done by de Maere, Ehrenmann and Smeers 2016, with different market-designs (CfD, Forward Capacity Contracts, etc.). But they assume the only financial assets available for agents are the ones linked to the electricity markets. As we already mentionned, this sets aside the possibility for agents to partially hedge through other financial assets as is done implicitely in the CAPM. We thus use CAPM in the following model, but will not exhibit explicit risk-sharing between producers and consumers.

Besides these direct and indirect hedging possibilities, electricity producers can also benefit from portfolio diversification by investing in different generation technologies. Using Mean-Variance Portfolio theory, Roques, Newbery and Nuttall, 2008, show that investing in CCGTs in UK may be less risky for private investors due to the positive correlation between gas and electricity prices, thus strengthening this relationship, whereas it may be socially optimal to favour investment in nuclear and coal power plants alongside CCGTs in order to lower the correlation. Long-term PPAs and/or a lower cost of capital may incentivize private investors to choose a more diversified portfolio. Vertically integrated suppliers may also benefit from a diminished revenues variability through their retail contracts, as analysed by Aïd, Chemla, Porchet and Touzi, 2011. Such effects will not be taken into account, in order to remain close to the perfect competition interpretation of the Energy-Only model: portfolio effects may be read as cross-subsidies compared to a socially optimal generation mix. Any power plant is thus modelled as an independent producer (one technology) which only sells on the wholesale market.

III. ENDOGENIZING FINANCIAL RISK IN AN INVESTMENT MODEL

3.1. The model

We summarize the results taken from a previous paper (Peluchon 2019), since they will be used in the simulations. For peak capacity investment, the basic elements are similar to Lambin and Léautier, 2019 or Creti and Fabra, 2007. The only difference is that we endogenize the value of the capital cost through a stochastic discount rate. It is based on a previous work from Léautier and Peluchon, 2015. Demand l is not price responsive and distributed according to probability distribution function $f(.)$ and cumulative distribution function $F(.)$ on $[0, +\infty)$. Such a representation is equivalent to a load duration curve model, but does also represent a uncertain load curve, as long as no storage is included. By convention, we suppose it represents the distribution of load for one year. There are two stages in the model: in the first stage firms choose the capacity level k without knowing the level of load demand, then load demand is realized and production levels are chosen. Since demand is inelatic, with perfect competition the second stage is easy to depict. Production is either equal to demand, if there is enough capacity, or equal to capacity if demand is higher, and demand must be curtailed. When this is the case, the price is set at the Value of Lost Load (VoLL), which is the consumer gross surplus derived from the consumption of electricity, estimated at V (Joskow and Tirole, 2007). Consumers are then indifferent between consuming electricity or not. This also means that there is no missing money in the model, as there is no price-cap. The (peaking) technology has a variable cost noted c. Perfect competition implies that the price is either c, when demand is lower than installed capacity k, or V, when demand is higher than k. Thus, the only source of uncertainty in the model is load demand l. We do not take into account fossil fuel prices volatility, which can be significant, but is difficult to modelize. In practice, fossil-fuel prices uncertainty is tackled through different variable costs scenarios (see the IEA World Energy Outlook for example).

Profit is thus a random variable, whose expression by unit of capacity in state of nature ω is:

$$\pi\left(l\left(\omega\right), k\right) = \left(V - c\right) \mathbb{I}_{\{l \geq k\}}$$

Investment cost is I and happens at time $t = 0$. Profit is a random variable whose value is realized at $t = 1$, and has to be discounted at $t = 0$. The discount rate is the return of the capacity investment. For the state of nature ω and installed capacity k, the return for one unit of capacity is:

$$R\left(l\left(\omega\right), k\right) = \frac{\pi\left(l\left(\omega\right), k\right)}{I}$$

The return R is a random variable. The free-entry condition can now make explicit the cost of capital R in capacity cost c_k.

$$\mathbb{E}\left[\pi\right] = c_k = \mathbb{E}\left[R\right] I$$

$$\Leftrightarrow \left(V - c\right) \mathbb{E}\left[\mathbb{I}_{\{l \geq k\}}\right] = c_k = \mathbb{E}\left[R\right] I$$

$$\Leftrightarrow \left(V - c\right) \mathbb{P}\left(l \geq k\right) = c_k = \mathbb{E}\left[R\right] I$$

3.2. The cost of capital with the Capital Asset Pricing Model

In the Capital Asset Pricing Model, the cost of capital is given by the covariance of the asset's return with the market portfolio's return η. We will assume that random variables in the model belong to probability space $\mathbb{L}^2(\Omega, \mathcal{F}, \mathbb{P})$, which is a Hilbert space (we follow here Demange and Rochet, 1992 exposition, itself taken from a 1982 paper by Kreps). For a random return $R_i = \frac{\pi_i}{P}$, the CAPM equation states that:

$$\mathbb{E}[R_i] = R_0 + \frac{cov(R_i, \eta)}{var(\eta)}(\mathbb{E}[\eta] - R_0)$$

With R_0 the risk-free return and the parameter $\frac{cov(R_i,\eta)}{var(\eta)}$ named the beta. The same equation can be stated in cash-flows, with P the price of the asset:

$$\mathbb{E}\left[\frac{\pi_i}{P}\right] = R_0 + \frac{cov\left(\frac{\pi_i}{P}, \eta\right)}{var(\eta)}(\mathbb{E}[\eta] - R_0)$$

$$\Leftrightarrow \mathbb{E}[\pi_i] = PR_0 + \frac{cov(\pi_i, \eta)}{var(\eta)}(\mathbb{E}[\eta] - R_0)$$

$$\Leftrightarrow \frac{1}{R_0}\left[\mathbb{E}[\pi_i] - \frac{cov(\pi_i, \eta)}{var(\eta)}(\mathbb{E}[\eta] - R_0)\right] = P$$

$$\Leftrightarrow \frac{\mathbb{E}[\pi_i]\left[1 - cov\left(\frac{\pi_i}{\mathbb{E}[\pi_i]}, \eta\right)\frac{(\mathbb{E}[\eta]-R_0)}{var(\eta)}\right]}{R_0} = P$$

The price at $t = 0$ of a random cash-flow is its expectation minus a risk-adjustment, discounted with the risk-free rate at $t = 0$. The value of the risk-adjustement is given by the covariance between the random cash-flow and the random market portfolio return. This is the certainty-equivalent approach proposed by Fama, 1977 and used by Smeers Ehrenmann, 2011b.

Remark that the risk-adjusted discount rate is equal to:

$$\mathbb{E}[R_i] = \frac{R_0}{\left[1 - cov\left(\frac{\pi_i}{\mathbb{E}[\pi_i]}, \eta\right)\frac{(\mathbb{E}[\eta]-R_0)}{var(\eta)}\right]}$$

The market portfolio's return is exogenous. We assume that changes in the electricity sector do not modify the equilibrium in the financial markets, as given by the CAPM. Remark that assuming an asset's return is given by the preceding equation means that the asset belongs to the market-span (the subspace of $\mathbb{L}^2(\Omega, \mathcal{F}, \mathbb{P})$ spanned by the finite number of assets included in the market portfolio).

3.3. Endogenizing the cost of capital

The return to the investment is $\frac{\pi}{I}$. Investment cost is here analogous to the price of a security, whose uncertain cash-flow is the gross margin generated by selling electricity on the wholesale electricity market. In order to get the equilibrium rate of return, we need to compute the risk-adjustment implied by the CAPM. We have:

$$cov[\pi, \eta] = \mathbb{E}[\pi\eta] - \mathbb{E}[\pi]\mathbb{E}[\eta]$$

$$\Leftrightarrow cov\left[\pi,\eta\right]=\mathbb{E}\left[\pi\eta\right]-\left(V-c\right)\mathbb{P}\left(l\geq k\right)\mathbb{E}\left[\eta\right]$$
$$\Leftrightarrow cov\left[\pi,\eta\right]=\left(V-c\right)\left\{\mathbb{E}\left[\eta\times\mathbb{I}_{\{l\geq k\}}\right]-\mathbb{P}\left(l\geq k\right)\mathbb{E}\left[\eta\right]\right\}$$

To simplify these expressions, observe that we can write:

$$\eta=\mathbb{E}\left[\eta\right]+\frac{cov\left(l,\eta\right)}{var\left(l\right)}\left(l-\mathbb{E}\left[l\right]\right)+\varepsilon$$

where $p=\frac{cov[l,\eta]}{var[l]}$ is the parameter from a linear regression on the subspace of $\mathbb{L}^2\left(\Omega,\mathcal{F},\mathbb{P}\right)$ spanned by the constant function 1 and $l-\mathbb{E}\left[l\right]$.

By definition, the first part is the orthogonal projection for the inner product associated with the expectation operator, and the second part is $\varepsilon=\eta-\mathbb{E}\left[\eta\right]-p\left(l-\mathbb{E}\left[l\right]\right)$. By construction of the inner product, ε and $l-\mathbb{E}\left[l\right]$ are orthogonal, as are ε and the constant function 1. Furthermore, $\mathbb{E}\left[\varepsilon\right]=0$, and ε is independent of l. p has the same sign as the correlation between η and l.

Thus, for any conditioning event $\{l\in A\}$:

$$\mathbb{E}\left[\eta\times\mathbb{I}_{\{l\in A\}}\right]=\mathbb{E}\left[\left(\mathbb{E}\left[\eta\right]+p\left(l-\mathbb{E}\left[l\right]\right)+\varepsilon\right)\times\mathbb{I}_{\{l\in A\}}\right]$$
$$\Leftrightarrow\mathbb{E}\left[\eta\times\mathbb{I}_{\{l\in A\}}\right]=\mathbb{E}\left[\eta\right]\mathbb{E}\left[\mathbb{I}_{\{l\in A\}}\right]+p\mathbb{E}\left[l\times\mathbb{I}_{\{l\in A\}}\right]-p\mathbb{E}\left[l\right]\mathbb{E}\left[\mathbb{I}_{\{l\in A\}}\right]+\mathbb{E}\left[\varepsilon\times\mathbb{I}_{\{l\in A\}}\right]$$
$$\Leftrightarrow\mathbb{E}\left[\eta\times\mathbb{I}_{\{l\in A\}}\right]=\mathbb{E}\left[\eta\right]\mathbb{P}\left(A\right)+p\mathbb{E}\left[l\times\mathbb{I}_{\{l\in A\}}\right]-p\mathbb{E}\left[l\right]\mathbb{P}\left(A\right)+\mathbb{E}\left[\varepsilon\right]\mathbb{P}\left(A\right)$$
$$\Leftrightarrow\mathbb{E}\left[\eta\times\mathbb{I}_{\{l\in A\}}\right]=\mathbb{E}\left[\eta\right]\mathbb{P}\left(A\right)+\mathbb{P}\left(A\right)\times p\left\{\mathbb{E}\left[l\mid l\in A\right]-\mathbb{E}\left[l\right]\right\}$$

since ε is independent of l and $\mathbb{E}\left[\varepsilon\right]=0$. Thus:

$$cov\left[\pi,\eta\right]=\left(V-c\right)\left\{\mathbb{P}\left(l\geq k\right)\times p\left[\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right]-\mathbb{P}\left(l\geq k\right)\left(\mathbb{E}\left[\eta\right]-\mathbb{E}\left[\eta\right]\right)\right\}$$
$$\Leftrightarrow cov\left[\pi,\eta\right]=\left(V-c\right)\mathbb{P}\left(l\geq k\right)p\left\{\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right\}$$

Since $\mathbb{E}\left[l\,|l\geq k\right]>\mathbb{E}\left[l\right], cov\left[\pi,\eta\right]>0\Leftrightarrow p>0\Leftrightarrow cov\left[l,\eta\right]>0$, which makes intuitive sense. We can now restate the free entry condition as:

$$\Leftrightarrow\mathbb{E}\left[\pi\right]=\mathbb{E}\left[R\right]I=\frac{R_0}{\left[1-cov\left(\frac{\pi_i}{\mathbb{E}[\pi_i]},\eta\right)\frac{(\mathbb{E}[\eta]-R_0)}{var(\eta)}\right]}I$$
$$\Leftrightarrow\mathbb{E}\left[\pi\right]-cov\left(\pi,\eta\right)\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}=R_0I$$
$$\Leftrightarrow\mathbb{E}\left[\pi\right]-cov\left(\pi,\eta\right)\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}=R_0I$$
$$\Leftrightarrow\left(V-c\right)\mathbb{P}\left(l\geq k\right)\left\{1-p\left\{\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right\}\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}\right\}=R_0I$$

The expression between brackets is the risk-adjustement to expected profit. In order to alleviate the notations, we note $\varphi=\frac{(\mathbb{E}[\eta]-R_0)}{var(\eta)}$ the exogenous parameter derived from the financial markets equilibrium. Finally:

$$\left(V-c\right)\mathbb{P}\left(l\geq k\right)\left\{1-\varphi p\left\{\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right\}\right\}=R_0I$$

The left part of the equation is decreasing, and for an admissible range of values this uniquely defines the equilibrium (see annex A in Peluchon, 2019). The positive correlation between load and the market portfolio return implies that the risk-adjustement is higher for high load states of nature.

In the interpretation we give of the equations as representing an EO design, one assumption is important: by considering only new capacity whose time to build is around 3 to 5 years, it is impossible to hedge cash-flow uncertainty through futures or options, since there is virtually no liquidity for electricity derivatives at a longer maturity. The model can easily be extended to different technologies, as described in Peluchon, 2019.

IV. IMPACT OF FINANCIAL RISK IN AN ENERGY-ONLY MARKET

4.1. Assumptions

For the simulations, we have used 10 years of hourly realized french load demand (2006-2015) and have considered each year as an equiprobable demand scenario. This allows to build a load probability distribution for one representative year, taking into account hourly variability. Since there is no storage, the model is equivalent to a load duration curve on states of nature (we have 87 600 states of nature). For technologies costs, the International Energy Agency WEO 2018 assumptions have been used for CCGTs and supercritical coal. OCGTs costs are from RTE Bilan Prévisionnel 2017. We include a technology dubbed "decarbonized", which is dispatchable, but has the same costs parameters as offshore wind in RTE Bilan Prévisionnel 2017. This is meant to be an illustratation of non-emitting technologies, whose costs are mainly (or totally here) fixed costs.

We calculate the perfect competition equilibrium: the capacity found for each power plant allows it to only cover its fixed-cost, no more, no less. The fact that private investors decide their investment imply they will not accept losses, free entry then ensures that no profit higher than what is needed to remunerate investors is possible. We can think about the cost of capital as the cost of a production input for the power plant developper. Investors decide at which minimum expected return they are ready to supply capital given the variability of cash-flows of the power plant (gross margins).

Investment costs (which already include time to build) are taken into account through annuities with risk-adjusted cash-flows coherent with the capacity levels (see Ehrenmann Smeers 2011b for a discussion on how to proceed with the certainty-equivalent approch used in previous sections). Regarding CAPM parameters, an Equity Risk Premium of 5 % and a real risk-free rate of 2 % are used. Finally, a correlation of 0,1 between load and the market index CAC40. This is in line with what can be estimated on weekly values for 2011-2019 (0,09). Estimation with weekly values for 2010-2019 yields a lower figure at 0,07. But using monthly values give much higher numbers: 0,15 for 2010-2019 or 0,17 for 2011-2019. We settled on 0,1 as providing an order of magnitude (in Peluchon, 2019, daily values for CAC40 returns are used to estimate the correlation). The choice of the market-index could also have an impact on the correlation value.

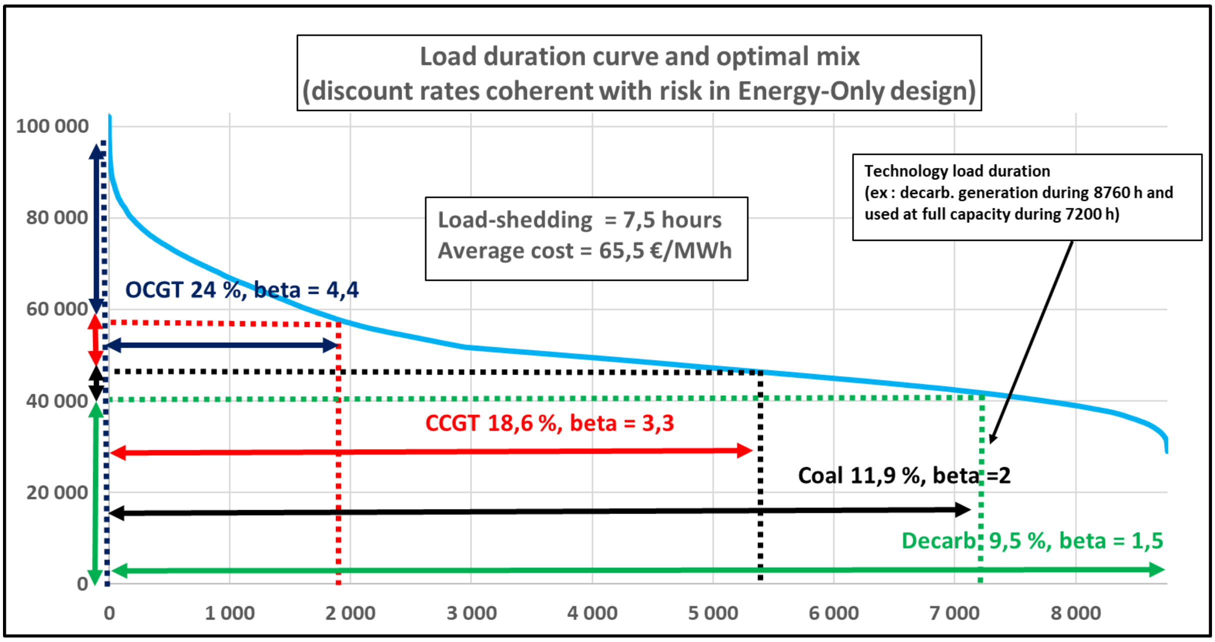
Furthermore, it should be stated that since we are not using the real probability distribution of load and that no existing capacities are included, our computations are only meant to show that, with realistic parameters, the effects can be be significant. A more thorough assessment would be required if we wanted to get an authoritative assessment of the costs of capital for the aforementionned generation technologies in France.

Fossil-fuels prices assumptions (including CO2) are given in the following table :

Commodity	Real prices
Coal ($/t)	60
Gas (€/MWh)	25
CO2 (€/t)	30
$/€ exchange-rate	1,2

4.2. Results with fossil fueled technologies allowed

An Energy-Only market would yield the following installed capacities and costs of capital at equilibrium:



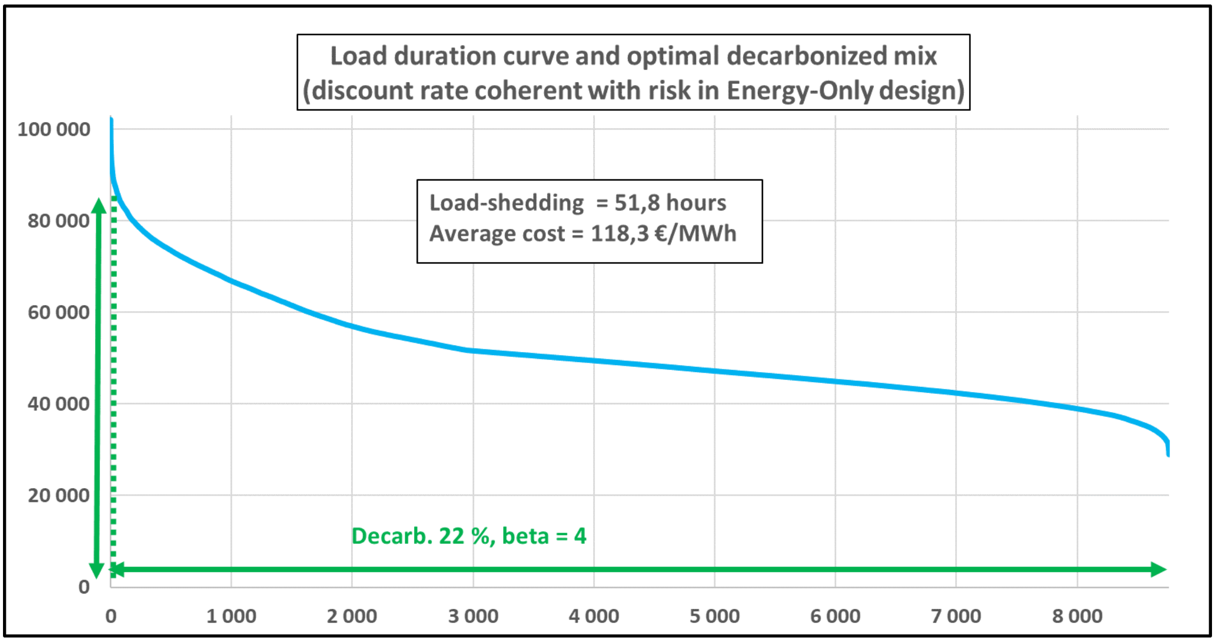
Energy-Only	Cost of capital	Asset-beta
OCGT	24,0 %	4,4
CCGT	18,6 %	3,3
Supercritical Coal	11,9 %	2,0
Decarbonized	9,5 %	1,5
Expected curtailement (hours)	7 h 30	
Average cost (€/MWh)	65,5	

This clearly shows that because of too much risk for peak capacity investment, the french SoS standard of an expected 3 hours of curtailment is not respected. Furthermore, the competitiveness of the different technologies cannot be assessed through LCOEs computed with the same discount rate. Technology specific (or even power plant specific) financial risk has to be taken into account in an Energy-Only setting. Without fossil-fuel prices volatility, the lower a power plant in the merit order stack, the lower its cost of capital. What is also interesting to notice, is that mid-merit power plants may be more risky than what is usually thought.

4.3. Net Zero mix with an Energy-Only market

Totally decarbonizing electricity generation implies that emitting technologies will not be allowed, whether through an explicit carbon value or an administrative decision.

An Energy-Only market would yield the following costs of capital at equilibrium for the first set of parameters (ERP 5 %, real risk-free rate 2 %):



Net Zero mix with Energy-Only	Cost of capital	Asset-beta
Decarbonized	22 %	4
Expected curtailement (hours)	51 h 48	
Average cost (€/MWh)	118,3	

The average cost of generation increases by 80,6 % due to the higher cost of capital for the remaining technology. Security of supply is greatly degraded, with expected curtailement at 51 hours and 48 minutes. Clearly the results point to a very high impact of decarbonization, through a very simple mechanism: the risk profile of the decarbonized technology becomes similar to that of a peak power plant. Since the margins earned by the decarbonized technology are concentrated at peak demand, they are much more volatile, and this increases the cost of capital compared to the previous

Energy-Only case.

4.4. Variable renewables and residual demand

Variable RES are bound to become a very significant part of electricity production: they already represented around 34 % of EU 27 gross electricity production in 2019, and this share is forecast to reach at least 65 % in 2030 (according to the Climate Target Plan impact assesment). Since they benefit from fixed-price contracts, investment in variable RES occur independently of the level of wholesale prices. Their variable cost is zero and as a consequence they are dispatched with first rank in the merit order stack. What load demand remains net of intermittent RES production is the residual demand: it is the effective demand adressed to other generation power plants. This explains why generation capacity expansion models can still be used for dispatchable technologies, as long as you substitute residual demand to total demand in the simulations.

The model presented in Section 3 and 4 can include residual demand instead of total demand, this does not change the analytical expressions. But this raises one issue: the correlation between residual demand and the market portfolio return is unknown, especially with an unknown future RES capacity level. Actually, it is better to keep using total demand, and remark that renewables production does not change the equation of optimal investment for peak capacity, unless there is a positive probability it exceeds the capacity implied by the equation. The latter is not the optimal peak capacity, but the optimal total capacity of all the technologies with a lower variable cost in the merit order stack.

Since only VOLL prices are remunerating peak capacity, a high proportion of RES probably does not change its cost of capital, since it would need a renewable production possibly as high as the highest load hours (around the highest 50 hours), that is in winter. All the hours with a positive margin for peak production belong to winter days, and are at a level such that no RES production can alter the picture. Therefore, the results are still valid for high variable RES penetration levels.

V. FLEXIBLE DEMAND

One objection that could be made to the previous assesment is that Demand Side Response (DSR), or storage, or even sector coupling could allow some positive prices outside of scarcity episodes. While introducing explicitely such possibilities in our model is impossible, we try to assess the consequences they could have on the cost of capital through simple examples.

5.1. Demand Side Response

Demand Side Response is very broadly a mechanism allowing a part of load demand to decrease if prices are higher than the variable cost of a peak power plant but lower than the VOLL. For the sake of simplicity, we will assume that load demand can be lowered to the installed capacity level with a constant price of 1000 €/MWh, with the exception of 3 hours during which the price will be set at VOLL.

Net Zero in Energy-Only design with DSR	Cost of capital	Asset-beta
Decarbonized	16 %	2,8
Excpected DSR (hours)	720 h	
Expected curtailement (hours)	3 h	
Average cost (€/MWh)	90	

Note that these results imply that 20 GW of demand response is available. This a huge number. Costs for the deployement of DSR are not included in the average cost. However, this very simple example shows easily that even if the equilibrium cost of capital can be lowered, it is far from levels that could be deemed acceptable. Any other mechanisms that allows some positive prices outside of scarcity episodes can be assessed in this way.

5.2. Linear elastic demand

Of course, a totally elastic demand is very far from being possible today. Nevertheless, we make this assumption as a thought experiment allowing us to assess whether this changes the results from section 4. If demand is completely price responsive, this may prevent the need for load-shedding. But this does not imply the level of capacity is adequate, at least from the point of view of the costs for consumers. We assume here an inverse linear elestic demand, as in Green and Léautier, 2017. Price P is given by the following equation, where ω is state of nature, and Q is the quantity consumers are willing to purchase at this price :

$$P\left(Q,\omega\right) = a(\omega) - bQ$$

We will assume a constant slope b, with $b > 0$. We get the following results for the Net-Zero Energy-Only equilibrium, for different b values.

For $b = 1$ €/MWh per MW of reduced demand :

Net Zero in Energy-Only design	Cost of capital	Asset-beta
Decarbonized	20,5 %	3,7
Expected hours with positive prices (hours)	205 h	
Average cost (€/MWh)	111,7	

For $b = 0,4$ €/MWh per MW of reduced demand :

Net Zero in Energy-Only design	Cost of capital	Asset-beta
Decarbonized	18,8 %	3,4
Expected hours with positive prices (hours)	405 h	
Average cost (€/MWh)	104,2	

For $b = 0,1$ €/MWh per MW of reduced demand :

Net Zero in Energy-Only design	Cost of capital	Asset-beta
Decarbonized	15,9 %	2,8
Expected hours with positive prices (hours)	1009 h	
Average cost (€/MWh)	91,4	

This last case yields similar results for the equilibrium cost of capital of the decarbonized technology and for the average cost than the DSR simulation of part 5.1. However, since prices are not constant, but are higher when the states of nature lead to a high demand, margins are more concentrated in the more "risky" states of nature (the ones with higher risk adjustements). This implies that a higher number of hours with positive prices are needed in order to cover the fixed costs.

As can be seen with these results, a more price responsive demand lowers the impact of decarbonization on the equilibrium cost of capital, but still leads to a very high increase compared to a carbonized Energy-Only mix. This means making demand more elastic will not prevent the problem.

Other changes in wholesale price formation could have the same properties. The introduction of storage or sector coupling could lead to positive prices outside of scarcity episodes. Those can not be included in the model, however the impact of more hours with positive prices can easily be assessed, as we have done very roughly with DSR in part 5.1. But further research is needed if we want to get an idea of how many such hours we will get with these evolutions.

VI. CONTRACT FOR DIFFERENCE

6.1. Impact on cost of capital

A Contracts for Difference (CfD) is a mechanism offering a guaranteed price for energy ("strike price") to a power plant, that is designed to function as a complement to an EO market. Financial flows either complete or lower the revenues generated on the wholesale market in order to attain the strike price level. We assume here that consumers are the counterparties to the CfD. They face the opposite financial flows, thus being guaranteed a price for their consumption. It is relatively straightforward to extend the results presented here to other technologies, using the results of section 4.

The strike price P is higher than variable cost c, and is the price received by the power plant every time it produces, whether load is lower or highe than installed capacityr. The profit for the whole of installed capacity is the random variable:

$$\pi_C = (P - c)\, l \times \mathbb{I}_{\{l \leq k\}} + (P - c)\, k \times \mathbb{I}_{\{l \geq k\}}$$

Expected profit is:

$$\mathbb{E}[\pi_C] = \mathbb{E}\left[(P - c)\, l \times \mathbb{I}_{\{l \leq k\}} + (P - c)\, k \times \mathbb{I}_{\{l \geq k\}}\right]$$

We need to compute the risk-adjustment for this random cash-flow, thus to compute the covariance with the market-portfolio return η:

$$cov\left[\pi_C, \eta\right] = cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}} + (P-c)\, k \times \mathbb{I}_{\{l \geq k\}}, \eta\right]$$

$$cov\left[\pi_C, \eta\right] = cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] + cov\left[(P-c)\, k \times \mathbb{I}_{\{l \geq k\}}, \eta\right]$$

We have already computed the second part of the right-hand side of the equality:

$$cov\left[(P-c)\, k \times \mathbb{I}_{\{l \geq k\}}, \eta\right] = (P-c)\, k\varphi p \left\{\mathbb{E}\left[l/l \geq k\right] - \mathbb{E}\left[l\right]\right\}$$

We use the same method for the first-part:

$$cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] = (P-c)\, cov\left[l \times \mathbb{I}_{\{l \leq k\}}, \eta\right]$$

$$cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] = (V-c)\left\{\mathbb{E}\left[l \times \eta \times \mathbb{I}_{\{l \leq k\}}\right] - \mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k\}}\right]\mathbb{E}\left[\eta\right]\right\}$$

With the orthogonal decomposition already used:

$$\eta = \mathbb{E}\left[\eta\right] + \frac{cov\left(l, \eta\right)}{var\left(l\right)}\left(l - \mathbb{E}\left[l\right]\right) + \varepsilon$$

$$cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] = (P-c)\, \varphi p \left\{\mathbb{E}\left[l^2 \times \mathbb{I}_{\{l \leq k\}}\right] - \mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k\}}\right]\mathbb{E}\left[l\right]\right\}$$

$$cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] = (P-c)\, \varphi p \mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k\}}\right]\left\{\frac{\mathbb{E}\left[l^2 \times \mathbb{I}_{\{l \leq k\}}\right]}{\mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k\}}\right]} - \mathbb{E}\left[l\right]\right\}$$

$$cov\left[(P-c)\, l \times \mathbb{I}_{\{l \leq k\}}, \eta\right] = (P-c)\, \mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k\}}\right] \varphi p \left\{\frac{\mathbb{E}\left[l^2/l \leq k\right]}{\mathbb{E}\left[l/l \leq k\right]} - \mathbb{E}\left[l\right]\right\}$$

Finally, the risk-adjusted expected profit is:

$$(P-c)\, \mathbb{E}\left[l/l \leq k\right] \mathbb{P}\left[l \leq k\right]\left(1 - \varphi p \left\{\frac{\mathbb{E}\left[l^2/l \leq k\right]}{\mathbb{E}\left[l/l \leq k\right]} - \mathbb{E}\left[l\right]\right\}\right)$$

$$+ (P-c)\, k\mathbb{P}\left[l \geq k\right]\left(1 - \varphi p \left\{\mathbb{E}\left[l/l \geq k\right] - \mathbb{E}\left[l\right]\right\}\right)$$

With a CfD, the free-entry condition then becomes:

$$(P-c)\, \mathbb{E}\left[l/l \leq k\right] \mathbb{P}\left[l \leq k\right]\left(1 - \varphi p \left\{\frac{\mathbb{E}\left[l^2/l \leq k\right]}{\mathbb{E}\left[l/l \leq k\right]} - \mathbb{E}\left[l\right]\right\}\right)$$

$$+ (P-c)\, k\mathbb{P}\left[l \geq k\right]\left(1 - \varphi p \left\{\mathbb{E}\left[l/l \geq k\right] - \mathbb{E}\left[l\right]\right\}\right) = R_0 k I$$

This yields a risk-adjusted discount-rate: $\mathbb{E}\left[R_C\right] =$

$$\frac{R_0}{\frac{\mathbb{E}[l/l \leq k]\mathbb{P}[l \leq k]}{\mathbb{P}[l \leq k]\mathbb{E}[l/l \leq k] + k\mathbb{P}[l \geq k]}\left(1 - \varphi p \left\{\frac{\mathbb{E}[l^2/l \leq k]}{\mathbb{E}[l/l \leq k]} - \mathbb{E}\left[l\right]\right\}\right) + \frac{k\mathbb{P}[l \geq k]}{\mathbb{P}[l \leq k]\mathbb{E}[l/l \leq k] + k\mathbb{P}[l \geq k]}\left(1 - \varphi p \left\{\mathbb{E}\left[l/l \geq k\right] - \mathbb{E}\left[l\right]\right\}\right)}$$

The risk-adjustment is a weighted mean of the EO risk-adjustement and of a lower risk-adjustment factor used for states of nature with lower load demand. We can restate the free-entry condition as:

$$\frac{\mathbb{E}\left[\pi_C\right]}{\mathbb{E}\left[R_C\right]} = kI$$

If the strike price is set such that expected profit is the same than in the EO design with the EO equilibrium capacity level, we can write:

$$\mathbb{E}[\pi_C] = \mathbb{E}[\pi_{EO}]$$

Since we have (for any k):

$$\frac{1}{\mathbb{E}[R_C]} > \frac{1}{\mathbb{E}[R_{EO}]}$$

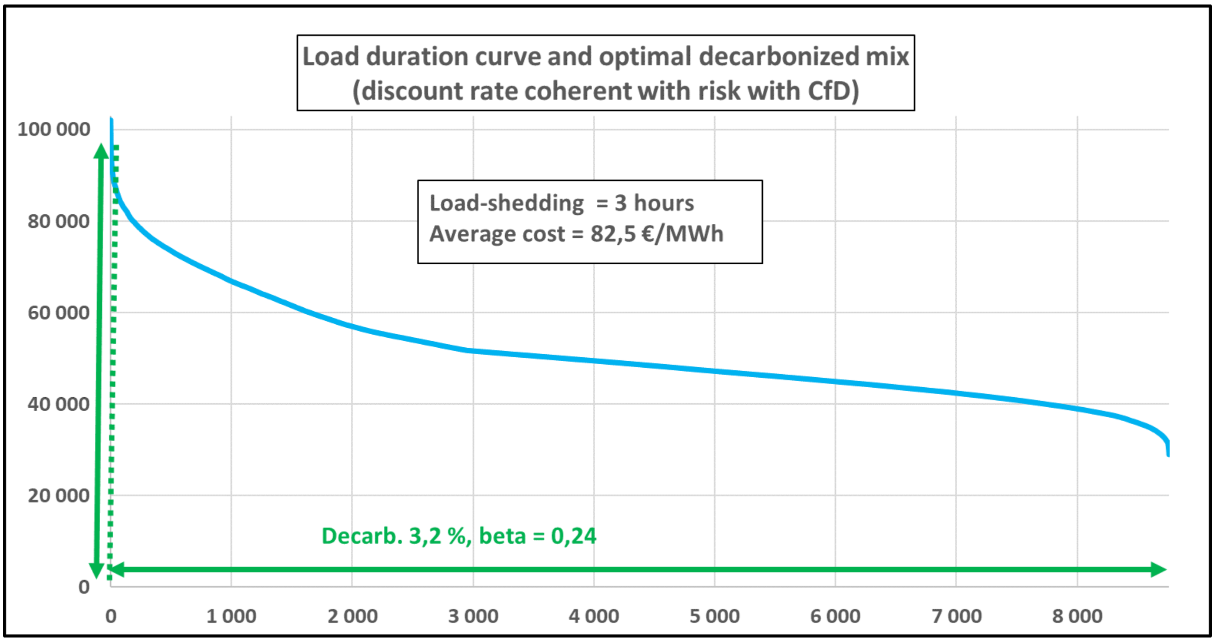
For k at EO equilibrium level:

$$\frac{\mathbb{E}[\pi_C]}{\mathbb{E}[R_C]} > \frac{\mathbb{E}[\pi_{EO}]}{\mathbb{E}[R_{EO}]}$$

With perfect competition pushing for an equalization between investment costs and risk-adjusted expected profits, capacity level with a CfD will be higher than in an EO market-design for this strike price value. There is a one-to-one relationship between strike price P and equilibrium installed capacity k_C, defined implicitely by the free entry condition. Choosing a value for P will yield a value for k_C, while choosing a capacity target k_C implies setting the strike price value to P. k_C is an increasing function of P. The choice of the strike price can either result from an auction setting it competitively, or from the choice of a capacity level deemed as desirable by the regulator.

6.2. Optimal decarbonized mix with a CfD

The strike price is set such that installed capacity with perfect competition respect the french security of supply standard of an expected 3 hours of curtailement. The CfD lasts 25 years, the decarbonized power plant lifetime. Note that this is a CfD energy price, not a CfD on capacity price, as in the UK capacity market. The average price reflects the decrease of curtailments and the impact of the strike price. The cost of capital value is the internal rate of return, ie the discount rate setting the net present value of the cash-flows to zero, once the equilibrium capacity is found through the use of cash-flows specific risk adjustements. The same CAPM parameters are used than previously (ERP 5 %, real risk-free rate 2 %).



Net Zero mix with CfD	Cost of capital	Asset-beta
Decarbonized	3,2 %	0,24
Expected curtailement (hours)	3 h	
Average cost (€/MWh)	82,5	

A CfD has strong risk reduction properties. Since fixed-costs are spread out on the whole of production, margins are less volatile than in an Energy-Only market, this explains the strong reduction in the cost of capital at equilibrium. Note that, since only one technology is used, some power plants are only used for peak and mid-merit generation. As a consequencence the average load factor is not very high. This implies that different CfDs could be used. For example, one for peak/mid-merit and one for baseload production with a lower strike price, thus allowing a lower average cost for consumers.

It would certainly even be better to introduce some DSR in order to install less capacity. In fact, the optimal net zero mix with a 3.2 % discount rate for the decarbonized technology would imply 19 hours of load-shedding an an average cost of 77.1 €/MWh. By forcing more investment through a higher strike price in the previous chart, we are installing too much capacities than is socially warranted. It would be probably less costly to use some DSR. Using the same rough proxy than in part 5.1, ie a part of demand can be decreased through a 1000 €/MWh price, we obtain the following results :

Net Zero mix with CfD and DSR	Cost of capital	Asset-beta
Decarbonized	3,1 %	0,23
Expected DSR (hours)	320 h	
Expected curtailement (hours)	3 h	
Average cost (€/MWh)	65,5	

It is thus possible to lower the average costs for consumers with some DSR activated at 1000 €/MWh : this allows to respect the Security of Supply standard while decreasing the strike price for the decarbonized technology CfD. This even allows to completely prevent the increase in average cost compared to the Energy-Only results with fossil fuel generation allowed.

VII. CONCLUSION

Reaching net zero in the electricity sector requires huge investments in the coming decades. These investments will only happen if the right incentives are set. Amongst those is the financing cost developpers will face, as they will need to recoup fixed costs through their revenues. As already explained by Joskow (2021) or Newbery (2016, 2019), a decarbonized electricity sector will face higher costs of capital in an Energ-Only model. Building on a previous work showing how to endogenize the cost of capital in a simplified generation capacity expansion model, we use this formal setting to quantify this impact on french load datas, and show that it may be very important. Contrary to what is often said, a more price responsive demand will not reverse this assessment, as we also show through our calculations. As a consequence, security of supply will be degraded and the costs for electricity consumers will increase compared to today, creating social redistribution issues and potentially hindering industry's competitiviness. Introducing long-term constracts, and going towards hybrid markets, can prevent those problems and make the energy transition less challenging than it is already. More research is needed to refine this conclusion, especially regarding the practical organization of hybrid markets, but we believe that the issue raised by decarbonization through financial risk is sufficiently solid to warrant a change of paradigm in electricity market design thinking.

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