Market Design and the Cost of Capital for Generation Capacity Investment

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Abstract

We study the impact of market design on the required rate of return asked by investors (the cost of capital) for generation capacity investments. We find that, if the Capital Asset Pricing Model applies and there is a positive correlation between electricity demand and the market return, then different generation technologies have different costs of capital at equilibrium in an Energy-Only setting. We show that peak capacity underinvestment can be explained by financial risk, even in the absence of the so-called "missing-money" problem. Analytic expressions of the equilibrium cost of capital are obtained in a simplified generation capacity expansion model. In order to respect generation adequacy standards, fixed-price contracts or capacity markets should be introduced, as was done in the UK with the Electricity Market Reform. We find that Contracts for Difference (CfDs) or capacity markets lower the equilibrium cost of capital, and thus lead to more capacity investment when perfect competitition applies, as well as to lower expected costs for consumers. As a consequence, these mechanisms should not be seen as subsidies, but as welfare improving market-design reforms. By opposition, strategic reserves are not an efficient capacity mechanism: they have no cost of capital reduction properties and only add costs to an EO design.

Keywords: generation adequacy; capacity remuneration schemes; electricity market design; cost of capital.

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1 Introduction

Decarbonization and the other energy-climate targets (Renewable Energy Supply and Energy Efficiency) are the main drivers of the electricity sector evolution in the European Union. With the recent Trilogue negotiation outcome on Governance Regulation, carbon neutrality has become the target around 2050. At the same time, RES and EE 2030 targets at the European Union level have been set at 32 % of final energy consumption for RES, and 32,5 % for EE. The first target is bound to yield a proportion of RES in 2030 EU 28 net electricity production of around 60 % (versus 31 % in 2017), as estimated by Thomson-Reuters in a recent analysis. Recent modelling performed with the PRIMES model for the European Commission ("non-paper") gives a lower estimate of 49 % of net electricity production, for a scenario with a 33 % RES target in final energy consumption and a 33 % energy efficiency target. The increase of RES production will mainly be done through wind and solar production, since hydraulic production is constrained by the lack of potential sites for new capacities. Furthermore, the share of low carbon generation (RES and nuclear) would reach 70 % of EU 28 net electricity generation in 2030. Finally, fossil-fuel generation is being progressively phased-out through the combination of Emissions Performance Standards, carbon price floors (UK, NL) or the higher EU-ETS prices expected with the introduction of the Market Stability Reserve. Many countries have now indicated an end date for coal generation, even if the policy instruments used are not yet defined. In order to reach a carbon neutrality target, other fossil fuels power plants will need to be phased out. In the medium to long-term, the electricity sector will thus only include zero-emissions generation technologies, such as RES and / or nuclear energy. It is hoped that intermittency of variable RES will be managed through the development of electricity storage and / or through Demand Side Response (DSR), since at each time an electric grid must ensure equality between supply and demand in order to prevent a blackout. In the meantime, flexible generation capacities will be needed, such as Combined Cycle Gas Turbines. But their profitability has been impaired by a decreasing residual demand (total demand less RES production), leading to worries that existing plants will be closed or that no needed investment will happen. As a consequence, Capacity Remuneration Schemes (CRMs) have been set-up in order to tackle this issue, each Member-States choosing a different design, prompting call for a european harmonization. At the same time, the need for CRMs is contested, and the choice between capacity markets or strategic reserves hotly debated. The European Commission has so far indicated that CRMs are only transitorily needed.

Since zero emissions generation technologies are capital intensive (they have high capital costs and low or even zero variable costs), it has also been argued that without any reform of the electricity wholesale market, the required rate of return asked by investors (the cost of capital) will be higher in a carbon-free electricity sector, because of the higher volatility of generation plants margins. Wholesale electricity markets in Europe are mainly of the Energy-Only kind: that is, the only remuneration power plants get comes from selling electricity on the market at a different price each hour (or half-hour) of the year. Roughly speaking, power plants are stacked in an order given by their variable costs (the so-called "merit-order"), then cost minimization implies that the price is set by the variable cost of the last power plant needed to fulfill the demand, that is the one with the higher cost among those needed. In a fully decarbonized electricity system, most of the time the wholesale electricity price will be nil or at a low variable cost. For some power plants, it is only when DSR or storage will be needed to balance supply and demand, that they will be able to cover their fixed costs. Margins will thus possibly be more volatile, implying a higher cost of capital. In order to lower the cost of the transition, Grubb and Newbery, 2018, argue that fixed-price contracts should be introduced for those technologies. RES already benefit from such contracts, given that their immaturity a few years ago required government subsidies to foster their development. Since then, their costs have hugely decreased, implying a possible end to subventions. But RES developers are asking for contracts to remain of the fixed-price kind in order to keep their cost of capital low (Wind Europe 2017). For RES and nuclear power plants, such kind of contracts have been set as Contracts-for-Difference (CfDs) in the

UK by the Electricity Market Reform.

In this context, the question of what impacts the cost of capital for new capacity investment has become an important topic. We focus here on generation adequacy, that is whether CRMs give the right incentives to reach a level of total capacity seen as needed to prevent curtailments (demand rationning) and blackouts. This paper proves that: (1) peak power plants have a high cost of capital and that is enough to explain generation adequacy issues ; (2) relative competitiveness of the different technologies should be assessed with technology specific costs of capital, provided that the Capital Asset Pricing Model (CAPM) applies, and that the correlation between load demand and the market is positive and high enough. This is done in a classic setting, a simplified generation capacity expansion model with an uncertain and inelastic demand, that remains widely used in the sector, including in policy studies. Actually, the effect may be important, as a first-pass with french datas seems to conclude. We show that: (3) the introduction of a capacity market or of CfDs lower the cost of capital, and as a consequence leads to more investment at equilibrium ; (4) this can increase the social surplus compared to an Energy-Only design, as seems to be the case with french datas. Capacity markets or CfDs should not be considered as subsidies, since they help to tackle a market failure: the lack of financial instruments allowing a mutually benefiting risk sharing between producers and consumers. By contrast, Strategic Reserves do not lower the cost of capital: they are less efficient than the other capacity mechanisms. Those properties should be taken into account by regulators in the european debate about CRMs.

Section 2 reviews the litterature. Section 3 describes the basic model, with only one technology. The results are extended with different generation technologies in section 4. When load demand and the market portfolio are positively correlated, the different generation technologies have costs of capital ranked by their merit-order. Section 5 uses the model on french datas to show that peak capacity has a high cost of capital in an Energy-Only setting and computes equilibrium costs of capital for CCGTs and coal power plants. Section

6 shows that a capacity market lowers the cost of capital and allows a decrease of prices paid by the consumers. A strategic reserve does not have the same properties, since the cost of capital for new investment is not modified. Section 7 arrives to the same conclusions with a CfD. Section 8 is the welfare analysis. Section 9 concludes.

2 Litterature Review

The idea that financial risk is an important driver of investment in deregulated electricity sectors has initially emerged in the economic literature through the debates around generation adequacy. It has been alleged that Energy-Only markets do not yield enough capacity to meet Security of Supply (SoS) standards and that has mainly been explained by so-called "missing-money" (Joskow 2008, Cramton and Stoft 2005 & 2008). Prices are prevented from being high enough when capacity is scarce, thus taming the incentives to invest in peaking power plants. The different mechanism proposed to remedy this problem are gathered under the Capacity Requirement Mechanisms expression. More recently, 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 put the spotlight on financial risk as an explanation for alleged underinvestment, even in the absence of missing-money. 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. This volatility translates into higher hurdle rates than usual, and less investment than thought when financial risk is not taken into account. 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 computations, 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).

At the same time, the growing realisation of the risks posed by climate change has led a number of countries to pass regulations constraining greenhouse gas (GHG often improperly labelled as CO2) emissions of the electricity sector. The European Union has been a pioneer on that front, setting a cap and trade as early as 2005 (EU-ETS) for different sectors including electricity, and has completed the emissions reductions target with RES and EE targets in 2020 and 2030. With the help of fixed-price contracts (FiT), it has led to a very important development of solar and wind generated electricity (EU28 production went from around 20 TWh in 2000 to slightly less than 500 TWh today). But the 2008 economic crisis coupled with policy overlaps between RES and GHG policies have led to low ETS prices, languishing for a long time around 5 €/t, a level seen as much too low to incentivize investment in cleaner production facilities, unless they already benefit from a FiT. Furthermore, the variability of solar and wind production has created concerns that they create new risks for investments in other technologies, which are seen as needed to provide the necessary flexibility of supply to load demand variations. The combination of decarbonization and generation adequacy issues 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, dubbed missing markets by Newbery, 2016, by analogy with the missing money problem. As Gollier, 2015, reminds, with incomplete markets, social and private valuations are different, since all the mutually benefiting risk-sharing operations can not be performed. As a consequence, competitive equilibrium outcomes may not be socially optimal, and some regulatory interventions may be welfare improving. 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.

3 Endogenizing financial risk in an investment model

3.1 The basic model

The basic elements are similar to Lambin and Léautier, 2018 or Creti and Fabra, 2007, the only difference is that we endognize 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 screening 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 does not require any choice from the agents. 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.

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

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

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

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:

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

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

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

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

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, 1997 and used by Smeers Ehrenmann, 2011b.

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

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

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 $\mathbb{L}^2\left(\Omega, \mathcal{F}, \mathbb{P}\right)$ 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:

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

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

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

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 $\{l \in A\}$:

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

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

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

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

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

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

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

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

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

$$\mathbb{E}\left[\pi\right]-cov\left(\pi,\eta\right)\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}=R_0I$$

$$\mathbb{E}\left[\pi\right]-cov\left(\pi,\eta\right)\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}=R_0I$$

$$\left(V-c\right)\mathbb{P}\left(l\geq k\right)\left\{1-p\left\{\mathbb{E}\left[l\left|l\geq k\right.\right]-\mathbb{E}\left[l\right]\right\}\frac{\left(\mathbb{E}\left[\eta\right]-R_0\right)}{var\left(\eta\right)}\right\}=R_0I$$

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:

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

The left part of the equation is decreasing, and for an admissible range of values this uniquely defines the equilibrium (see annex A). 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.

4 The model with different technologies

4.1 The merit-order

We note installed capacity for technology / unit j as $\mathring{k}_j$. Define $k_j = \sum_{i=1}^{j} \mathring{k}_j$. Thus, k_j is the total capacity up to j-th level in dispatch merit-order. The vector $k = (k_1, ..., k_j, ...k_n)$ defines the whole generation park.

Since the price in state ω will be equal to the variable cost of the marginal unit, the profit of unit j in state ω for capacity vector k is:

$$\pi_j \left(l \left(\omega \right), k \right) = \sum_{i=j}^{n} \left(c_{i+1} - c_j \right) \mathbb{I}_{\{k_{i+1} \geq l(\omega) \geq k_i\}}$$

We can remark that π_j is independant of capacities shares below j in merit-order. It can be simplified as:

$$\pi_j \left(l, k \right) = \sum_{i=j}^{n} \left[\left(c_{i+1} - c_{j+1} \right) + \left(c_{j+1} - c_j \right) \right] \mathbb{I}_{\{k_{i+1} \geq l \geq k_i\}}$$

$$\pi_j \left(l, k \right) = \sum_{i=j}^{n} \left(c_{i+1} - c_{j+1} \right) \mathbb{I}_{\{k_{i+1} \geq l \geq k_i\}} + \left(c_{j+1} - c_j \right) \sum_{i=j}^{n} \mathbb{I}_{\{k_{i+1} \geq l \geq k_i\}}$$

By convention, we write k_{n+1} for the highest possible load level, c_{n+1} for VOLL, etc. This is just a matter of notation.

$$\pi_j \left(l, k \right) = \sum_{i=j}^{n} \left(c_{i+1} - c_{j+1} \right) \mathbb{I}_{\{k_{i+1} \geq l \geq k_i\}} + \left(c_{j+1} - c_j \right) \mathbb{I}_{\{l \geq k_j\}}$$

$$\pi_j \left(l, k \right) = \sum_{i=j+1}^{n} \left(c_{i+1} - c_{j+1} \right) \mathbb{I}_{\{k_{i+1} \geq l \geq k_i\}} + \left(c_{j+1} - c_j \right) \mathbb{I}_{\{l \geq k_j\}}$$

$$\pi_j \left(l, k \right) = \pi_{j+1} \left(l, k_{j+1} \right) + \left(c_{j+1} - c_j \right) \mathbb{I}_{\{l \geq k_j\}}$$

Taking expectation:

$$\mathbb{E}\left[\pi_j\left(l,k\right)\right]=\mathbb{E}\left[\pi_{j+1}\left(l,k\right)\right]+\left(c_{j+1}-c_j\right)\mathbb{E}\left[\mathbb{I}_{\{l\geq k_j\}}\right]$$

$$\mathbb{E}\left[\pi_j\left(l,k\right)\right]=\mathbb{E}\left[\pi_{j+1}\left(l,k\right)\right]+\left(c_{j+1}-c_j\right)\mathbb{P}\left(l\geq k_j\right)$$

By backward induction:

$$\mathbb{E}\left[\pi_j\left(l,k\right)\right]=\sum_{i=j}^{n}\left(c_{i+1}-c_i\right)\mathbb{P}\left(l\geq k_i\right)$$

Expected profit for unit j is independant of capacity shares of every unit besides j in merit-order.

4.2 Competitive Equilibrium for Energy-Only

At equilibrium, the capacity for each technology is thus that profit per unit of capacity equals the unit cost of capacity. Optimal capacity j is noted k_j^*. For peak capacity n:

$$e_n=\mathbb{E}\left[\pi_n\left(l,k\right)\right]=\left(V-c_n\right)\mathbb{P}\left(l\geq k_T^*\right)$$

By backward induction:

$$e_j=\sum_{i=j}^{n}\mathbb{E}\left[\pi_i\left(l,k\right)\right]=\sum_{i=j}^{n}\left(c_{i+1}-c_i\right)\mathbb{P}\left(l\geq k_i^*\right)=e_{j+1}+\left(c_{j+1}-c_j\right)\mathbb{P}\left(l\geq k_j^*\right)$$

Thus:

$$e_j-e_{j+1}=\left(c_{j+1}-c_j\right)\mathbb{P}\left(l\geq k_j^*\right)$$

Turning to covariance, we have:

$$\pi_j\left(l,k\right)=\sum_{i=j}^{n}\left(c_{i+1}-c_i\right)\mathbb{I}_{\left\{l\geq k_i^*\right\}}$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=cov\left[\sum_{i=j}^{n}\frac{\left(c_{i+1}-c_i\right)}{e_j}\mathbb{I}_{\left\{l\geq k_i^*\right\}},\eta\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=cov\left[\sum_{i=j}^{n}\frac{e_i}{e_j}\frac{\left(c_{i+1}-c_i\right)}{e_i}\mathbb{I}_{\left\{l\geq k_i^*\right\}},\eta\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\sum_{i=j}^{n}\frac{\left(c_{i+1}-c_i\right)}{e_j}cov\left[\mathbb{I}_{\left\{l\geq k_i^*\right\}},\eta\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\sum_{i=j}^{n}\frac{\left(c_{i+1}-c_i\right)}{e_j}\left[\mathbb{E}\left[\eta\times\mathbb{I}_{\left\{l\geq k_i^*\right\}}\right]-\mathbb{P}\left[l\geq k_i^*\right]\mathbb{E}\left[\eta\right]\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\sum_{i=j}^{n}\frac{\left(c_{i+1}-c_i\right)}{e_j}\left[\mathbb{E}\left[\eta\times\mathbb{I}_{\left\{l\geq k_i^*\right\}}\right]-\mathbb{P}\left[l\geq k_i^*\right]\mathbb{E}\left[\eta\right]\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\sum_{i=j}^{n}\frac{\left(e_i-e_{i+1}\right)}{e_j}\frac{\left(c_{i+1}-c_i\right)}{\left(e_i-e_{i+1}\right)}\left[\mathbb{E}\left[\eta\times\mathbb{I}_{\left\{l\geq k_i^*\right\}}\right]-\mathbb{P}\left[l\geq k_i^*\right]\mathbb{E}\left[\eta\right]\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\frac{1}{e_j}\sum_{i=j}^{n}\frac{\left(e_i-e_{i+1}\right)}{\mathbb{P}\left(l\geq k_i^*\right)}\left[\mathbb{E}\left[\eta\times\mathbb{I}_{\left\{l\geq k_i^*\right\}}\right]-\mathbb{P}\left[l\geq k_i^*\right]\mathbb{E}\left[\eta\right]\right]$$

Using $\eta=\mathbb{E}\left[\eta\right]+p\left(l-\mathbb{E}\left[l\right]\right)+\varepsilon$, we obtain:

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\frac{1}{e_j}\sum_{i=j}^{n}\frac{\left(e_i-e_{i+1}\right)}{\mathbb{P}\left(l\geq k_i^*\right)}\mathbb{P}\left[l\geq k_i^*\right]\left[p\mathbb{E}\left[l\mid l\geq k_i^*\right]-p\mathbb{E}\left(l\right)\right]$$

$$cov\left[\frac{\pi_j\left(l,k\right)}{e_j},\eta\right]=\frac{1}{e_j}\sum_{i=j}^{n}\left(e_i-e_{i+1}\right)p\left\{\mathbb{E}\left[l\mid l\geq k_i^*\right]-\mathbb{E}\left[l\right]\right\}$$

For $i\geq j$ we know that $e_i\leq e_j$, so: $e_i-e_{i+1}\geq 0$.

We also have:

$$\frac{1}{e_j}\sum_{i=j}^{n}(e_i - e_{i+1}) = 1$$

And $p > 0$, since we make the assumption that $cov\,[l, \eta] > 0$. Thus, the covariance between a unit's return and the market portfolio is a weighted mean of all the higher units' covariances, the weights being fixed-costs differences. Furthermore, the higher a unit in merit-order, the higher the difference between the conditionnal expectation of load demand and the unconditionnal expectation of load demand, ie the higher the associated risk-premium. A baseload unit should have the lowest cost of capital of all the possible technologies.

5 Impact of financial risk in an Energy-Only market

5.1 Illustration on french datas

In order to illustrate the results, 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 (we have 87 600 states of nature). For technologies costs, the International Energy Agency WEO 2016 assumptions have been used for OCGTs, CCGTs and supercritical coal. 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, two set of parameters have been used. The first, consisting of an Equity Risk Premium of 6 %, as used by RWE and E.ON in their 2015 financial reports, and a real risk-free rate of 2 %. The second, an Equity Risk Premium of 8 %, as recommanded by NERA Economic Consulting in its report "Electricity generation costs and hurle rates" (2015) prepared for UK's Department of Energy and Climate Change, and from the same source a real risk-free rate of 1 %. Finally, a correlation of 0,05 between load and the market index CAC40 has been computed for 2011-2015. Results are also given for a correlation of 0,1 corresponding to 2015 only. Correlation is difficult to estimate, and the values given should only be seen as giving an order of magnitude. 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)	85
Gas (€/MWh)	25
CO2 (€/t)	20
$/€ exchange-rate	1,2

An Energy-Only market would yield the following costs of capital at equilibrium for the first set of parameters (ERP 6 %, real risk-free rate 2 %):

Correlation	0,05	0,1
OCGT	12,9 %	24,7 %
CCGT	10,8 %	19,6 %
Supercritical Coal	7,8 %	12,4 %
Expected curtailement (hours)	4 h 24	7 h 30

With the second set of CAPM parameters (ERP 8 %, real risk-free rate 1 %), the results are:

Correlation	0,05	0,1
OCGT	16,1 %	33,5 %
CCGT	13,1 %	25,8 %
Supercritical Coal	8,8 %	15,3 %
Expected curtailement (hours)	5 h 12	9 h 54

This clearly shows that because of too much risk, 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 financial risk has to be taken into account.

5.2 Renewables and residual demand

Variable RES are bound to become a very significant part of electricity production: they already represent around 15 % of EU 28 net electricity production, and this share is forecast to reach between 34 to 44 % in 2030. 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. 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.

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. Specifically, this holds for a 50 % RES level in the mix (variable and not variable), as in the Ampere scenario from RTE. 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.

6 Capacity market and Strategic Reserve

6.1 Impact of a capacity market on the cost of capital of peaking plants

We note m the price of one unit of capacity. We assume it is known with certainty by investors and paid at $t = 1$ (since it is certain, this last assumption is just a convention, it has no impact on the results). The free-entry condition becomes:

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

Using the risk-adjustment of cash-flows, we get:

$$\mathbb{E}\left[\pi\right] - cov\left(\pi, \eta\right)\varphi = R_0 I$$

$$(V - c)\,\mathbb{P}\left(l \geq k\right) + m - \varphi cov\left((V - c)\,\mathbb{I}_{\{l \geq k\}} + m, \eta\right) = R_0 I$$

$$(V-c)\,\mathbb{P}(l \geq k) + m - (V-c)\,\varphi cov\left(\mathbb{I}_{\{l \geq k\}}, \eta\right) - \varphi cov(m, \eta) = R_0 I$$

Since m is a constant:

$$(V-c)\,\mathbb{P}(l \geq k) - (V-c)\,\varphi cov\left(\mathbb{I}_{\{l \geq k\}}, \eta\right) = R_0 I - m$$

We find the same expression than in section 3, albeit with a different investment cost:

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

By definition m can not be greater than I. The left hand side of the equation is a decreasing function of k. Since the right-hand side is lower, the capacity level ensuring the equality is higher. Thus, a capacity price leads to more installed capacity than in an EO design. Increasing m has the same effect than lowering I : it yields a higher equilibrium capacity. Regulators can set a capacity target, such as the one implied by an expected 3 hours of curtailement, the equation will yield the needed capacity price m. We note k_{CM} the capacity level target, and k_{EO} the equilibrium capacity in EO, with $k_{EO} < k_{CM}$. We can make explicit the lower cost of capital by using the equivalent risk-adjusted discount-rate:

$$\mathbb{E}[R_{MC}] = \frac{R_0}{\frac{(V-c)\mathbb{P}(l \geq k)}{(V-c)\mathbb{P}(l \geq k)+m}\left(1 - \varphi p\left\{\mathbb{E}\left[l\,|l \geq k\right] - \mathbb{E}[l]\right\}\right) + \frac{m}{(V-c)\mathbb{P}(l \geq k)+m}}$$

It is clear that the equilibrium cost of capital is lower with a capacity market than in the EO case.

6.2 Strategic Reserve

A strategic reserve is the direct procurement of some additional capacity by the TSO, with the provision that whenever the reserve is activated, the spot price is set at VOLL, even with no curtailement needed. This means that the free-entry condition is the same than in

EO: whenever load demand is higher than installed capacity, the price is V, whenever it is lower the price is c. The level of capacity in the reserve is simply the amount needed to be added to the EO case in order to respect the SoS standard. Those capacities are directly paid by the TSO and added to what the consumers pay. As a consequence, they will pay the same expected prices for load demand up to EO capacity, but they will consume more, since total capacity is higher. But as the price is V for states of nature with load demand between k_{EO} and k_{CM}, this increased consumption has no impact on their expected surplus, but they have to pay the fixed costs of the reserve.

6.3 Illustration on our dataset

In order to illustrate the impact of a capacity market, we set the capacity price such that the equilibrium capacity respect the SoS criterion of an expected 3 hours of curtailment. This price is certain and paid during the whole lifetime of the power plant (30 years here). In practice this is not the case, for example new capacities benefit from 15 years contracts in UK, then will receive uncertain capacity prices for the remainder of their lifetime. This means our computations tend to overestimate the impact of a capacity mechanism. The lower costs of capital imply lower expected prices paid by consumers, even after taking into account the capacity price. Computations have only been performed for OCGTs, the average price thus only reflect the decrease of curtailments and the impact of capacity price. The cost of capital value is the internal rate of return, ie the discount rate setting the net present value of the expected equilibrium cash-flows to zero. Equilibrium values are:

For a 30 years capacity price (ERP 6 %, real risk-free rate 2 %):

Correlation	0,05	0,1
Capacity price (€/MW)	13 000	24 700
OCGT cost of capital	9,9 %	12,4 %
Expected average price decrease vs EO	- 2,8 %	- 11 %
Expected curtailement (hours)	3 h	3 h

For a 30 years capacity price (ERP 8 %, real risk-free rate 1 %):

Correlation	0,05	0,1
Capacity price (€/MW)	16 100	26 300
OCGT cost of capital	10,5 %	12,6 %
Expected average price decrease vs EO	- 5,1 %	- 17,5 %
Expected curtailement (hours)	3 h	3 h

7 Contract for Difference

7.1 Impact on cost of capital

Contracts for Difference are usually not used for peak power plants (or as capacity CfDs), but for baseload power plants (RES and nuclear in UK). Anyway, we use the same equations than in section 6, in order to provide a treatment allowing comparisons between the different market-designs. It is relativeley straightforward to extend the results presented here to other technologies, using the results of section 4. A 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.

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 than installed capacity or higher. 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:

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

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:

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

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

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

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

Finally, the risk-adjusted expected profit is:

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

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

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

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

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

This yields a risk-adjusted discount-rate:

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

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:

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

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:

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

Since we have (for any k):

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

For k at EO equilibrium level:

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

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.

7.2 Result on dataset

We illustrate the impact of a CfD on peak capacity by comparison with EO results using our dataset. The strike-price is set such that installed capacity respect the french security of supply standard of an expected 3 hours of curtailement. The CfD lasts 15 years, lower than the power plant lifetime, then the market reverts to an EO scheme. Note that this is a CfD energy price, not a CfD on capacity price, as in the UK capacity market. Computations have only been performed for OCGTs, the average price thus only 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.

ERP 6 %, real risk-free rate 2 %:

Correlation	0,05	0,1
OCGT cost of capital	7,3 %	9,0 %
Expected average price decrease vs EO	- 5,3 %	-14,5 %
Expected curtailement (hours)	3 h	3 h

ERP 8 %, real risk-free rate 1 %:

Correlation	0,05	0,1
OCGT cost of capital	7,8 %	9,3 %
Expected average price decrease vs EO	- 7,9 %	-20,8 %
Expected curtailement (hours)	3 h	3 h

A CfD seems to have much stronger risk reduction properties than a capacity market. Since fixed-costs are spread out on the whole of production, margins are less volatile than with a capacity market, this explains the strong reduction in the cost of capital.

8 Welfare analysis

8.1 Capacity Market

The expression of expected consumer surplus in the EO case is:

$$W_{EO}^{c} = (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k_{EO}\}}\right]$$

In the case of a capacity market, expected surplus is:

$$W_{CM}^{c} = (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k_{CM}\}}\right] - mk_{CM}$$

$$W_{CM}^{c} = (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{l \leq k_{EO}\}}\right] + (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{k_{EO} \leq l \leq k_{CM}\}}\right] - mk_{CM}$$

$$W_{CM}^{c} = W_{EO}^{c} + (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{k_{EO} \leq l \leq k_{CM}\}}\right] - mk_{CM}$$

Using the equations defining equilibrium capacity in the two designs with risk-adjusted discount rates, we have:

$$(V - c)\,\mathbb{P}\left(l \geq k_{EO}\right) = I \times \mathbb{E}\left[R_{EO}\right]$$

$$(V - c)\,\mathbb{P}\left(l \geq k_{CM}\right) + m = I \times \mathbb{E}\left[R_{CM}\right]$$

$$m = (V - c)\,\mathbb{P}\left(k_{EO} \geq l \geq k_{CM}\right) + I\left(\mathbb{E}\left[R_{CM}\right] - \mathbb{E}\left[R_{EO}\right]\right)$$

Re-injecting the expression of capacity price m in the expected surplus expression:

$$W_{CM}^{c} - W_{EO}^{c} = (V - c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{k_{EO} \leq l \leq k_{CM}\}}\right] - (V - c)\,k_{CM}\mathbb{P}\left(k_{EO} \geq l \geq k_{CM}\right) - Ik_{CM}\left(\mathbb{E}\left[R_{CM}\right] - \mathbb{E}\left[R_{EO}\right]\right)$$

$$W_{CM}^{c} - W_{EO}^{c} = (V - c)\,\mathbb{E}\left[(l - k_{CM}) \times \mathbb{I}_{\{k_{EO} \leq l \leq k_{CM}\}}\right] + Ik_{CM}\left(\mathbb{E}\left[R_{EO}\right] - \mathbb{E}\left[R_{CM}\right]\right)$$

Since for l between k_{EO} and k_{CM}, $l \leq k_{CM}$, the first part of the difference between expected surplus in CM and EO is negative. The coexistence of the energy price with the capacity price creates a distorsion. The second part is positive, since $\mathbb{E}\left[R_{EO}\right] \geq \mathbb{E}\left[R_{CM}\right]$. It is the cost of capital reduction effect. The net effect is positive if the risk reduction is important (high Equity Risk Premium and / or high positive correlation between load and the market), negative in the other case. If we did not take into account the impact of financial risk (or if correlation was zero), we would have: $\mathbb{E}\left[R_{EO}\right] = \mathbb{E}\left[R_{CM}\right]$. Then:

$$W_{CM}^{c} - W_{EO}^{c} = (V - c)\,\mathbb{E}\left[(l - k_{CM}) \times \mathbb{I}_{\{k_{EO} \leq l \leq k_{CM}\}}\right] < 0$$

This is the result that Léautier and Lambin, 2018, find. Without any impact of risk, a capacity-mechanism degrades expected consumer welfare. If risk is important, then the second effect is greater than the first, and consumer surplus is improved.

On our dataset, a capacity market always improves the consumers welfare. Thus:

$$(V-c)\,\mathbb{E}\left[(l-k_{CM})\times\mathbb{I}_{\{k_{EO}\le l\le k_{CM}\}}\right]+Ik_{CM}\left(\mathbb{E}\left[R_{EO}\right]-\mathbb{E}\left[R_{CM}\right]\right)>0$$

$$W^c_{CM}>W^c_{EO}$$

8.2 Strategic Reserve

In a Strategic Reserve design, the equation defining optimal investment is the same as in EO. The capacity in the reserve is $k_{CM}-k_{EO}$ and the fixed-costs of this capacity are paid by consumers. Expected consumer surplus becomes:

$$W^c_{SR}=(V-c)\,\mathbb{E}\left[l\times\mathbb{I}_{\{l\le k_{EO}\}}\right]-IR_0\times(k_{CM}-k_{EO})$$

$$W^c_{SR}=W^c_{EO}-IR_0\times(k_{CM}-k_{EO})$$

$$W^c_{SR}<W^c_{EO}$$

Since there is no reduction in the cost of capital, and that the costs of the reserve are added to the costs of production of the EO equilibrium, a SR provokes a straight welfare degradation.

8.3 Contract for Difference

In the CfD case, expected consumer surplus is:

$$W^c_{C}=(V-P)\,\mathbb{E}\left[l\times\mathbb{I}_{\{l\le k_{C}\}}\right]+(V-P)\,\mathbb{E}\left[k\times\mathbb{I}_{\{l\ge k_{C}\}}\right]$$

Introducing a CfD increases the electricity price paid by consumers from c to P for states of nature with load demand lower than k_{EO}, while it lowers it from V to P for states of nature when load demand is higher. Since more capacity is installed, the CfD raises consumption for states of nature with load demand between k_{EO} and k_C. As a consequence:

$$W_C^c - W_{EO}^c = -(P-c)\,\mathbb{E}\left[l \times \mathbb{I}_{\{l \le k_{EO}\}}\right] + (V-P)\,\mathbb{E}\left[l \times \mathbb{I}_{\{k_{EO} \le l \le k_C\}}\right] + (V-P)\,\mathbb{E}\left[k \times \mathbb{I}_{\{l \ge k_C\}}\right]$$

On our datas, total effect is positive on expected surplus, if we set the strike-price at the level needed to obtain an expected 3 hours of curtailment.

8.4 Analysis

A lower cost of capital lead to expected surplus increase through lower expected prices, provided that the risk reduction is high enough. This is always the case with our dataset, since the CAPM parameters and the correlation values lead to high risk-premiums for peak capacity. We have limited our analysis to this measure of welfare, as RTE, 2018, has done in its impact study of the capacity market. But consumers could also have their own appreciation of risk and this could alter the conclusions. The possibility of a welfare increase lies in the fact that financial markets are incomplete: that prevents the possibility to achieve the social optimum through optimal risk-sharing. This is the “missing-makets” problem pointed by Newbery. This work has not studied how consumers value risk and how the different market-designs alter their risk-adjusted welfare. This is the subject of further work. Moreover, the question of what would be the risk aversion of the different consumers would need to integrate their portfolio decisions and describe financial markets, that would require to distinguish different kinds of consumers in order to get realistic results (do all electricity consumers own financial assets portfolios allowing some hedging ?).

Using the CAPM gives perhaps an optimistic view of the risks linked to generation capacity investment. Actually, only a small part of the risk is priced through this model:

systematic risk is a proportion of total variance equal to the square of the correlation with the market portfolio. This can be illustrated by writing the CAPM relationship with random variables:

$$R_i = R_0 + \frac{cov\left(R_i, \eta\right)}{var\left(\eta\right)}\left(\eta - R_0\right) + \varepsilon$$

Since by construction, ε is orthogonal to the market protfolio return η:

$$var\left(R_i\right) = \left(\frac{cov\left(R_i, \eta\right)}{var\left(\eta\right)}\right)^2 var\left(\eta\right) + var\left(\varepsilon\right)$$

$$var\left(R_i\right) = \left(\frac{\rho\sigma_{R_i}\sigma_\eta}{\sigma_\eta^2}\right)^2 \sigma_\eta^2 + var\left(\varepsilon\right)$$

$$\sigma_{R_i}^2 = \rho^2\sigma_{R_i}^2 + var\left(\varepsilon\right)$$

$$var\left(\varepsilon\right) = \left(1 - \rho^2\right)\sigma_{R_i}^2$$

$$var\left(R_i\right) = \rho^2 var\left(R_i\right) + \left(1 - \rho^2\right) var\left(R_i\right)$$

This equation decomposes the variance in systematic risk (wich is priced) and idiosyncratic risk (not priced). An asset with a correlation of 0,05 or 0,1 with the market would only see between 0,25 % and 1 % of its total variance have an impact on its cost of capital. If financial markets are less perfect than implied by the CAPM, and a part of idiosyncratic risk is priced, then the cost of capital could be much higher. In the last 20 years, financial theory has pointed to the existence of many anomalies leading to many other risk factors than the market explaining the returns of financial assets (Fama and French, 1993 for example). This should be studied in order to get the full picture of market-designs potential improvements.

9 Conclusion

We start by showing how to endogenize the cost of capital in a simplified generation capacity expansion model. This allows to show that different generation technologies have different levels of financial risk at equilibrium, and as a consequence, their competitivity should be assessed with different discount rates. Underinvestment in peak capacity can also be explained by too much risk, even if there is no missing-money (since the wholesale price is set at VOLL when demand is higher than capacity). In the european debate about the need for capacity mechanism, our results show that removing price-caps and letting the wholesale prices be as high as VOLL (Energy-Only design) will not be enough to tackle the generation adequacy problem. Other market-designs allowing a reduction in risk are needed. Contracts for difference and capacity markets have this property, but not strategic reserves. This should inform the European Commission and the Member-States policy debates. And the need for such capacity mechanisms will not be transitory, as long as financial markets will remain incomplete. This simple fact point to a change in the way the electricity sector should be regulated. The question of risk must be put at the center of the research agenda. More importantly, market-designs inducing a lower cost of capital are not necessarily subsidies, as many seem to think. Provided that the risk reduction is high enough, they increase consumers welfare through lower average prices. This point to the possibility to study and engineer other market-designs in order to maximize those potential gains and allow the transition to decarbonized electricity systems.

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Appendix

A Uniqueness of equilibrium

$$(V-c)\,\mathbb{P}\left[l\geq k\right]\left(1-\varphi p\left\{\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right\}\right)=IR_0$$

$$g\left(k\right)=IR_0$$

Of course, we suppose capacity payment is lower than investment cost, otherwise the producer gets a free-lunch. $g\left(k\right)$ is positive for a range of values $\left[0,k_{max}\right]$,with k_{max}defined by:

$$g\left(k_{max}\right)=0$$

$$\Leftrightarrow 1-\varphi p\left\{\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]\right\}=0$$

$$\Leftrightarrow \frac{1}{\varphi p}=\mathbb{E}\left[l\,|l\geq k\right]-\mathbb{E}\left[l\right]$$

$$\Leftrightarrow \mathbb{E}\left[l\,|l\geq k\right]=\mathbb{E}\left[l\right]+\frac{1}{\varphi p}=\mathbb{E}\left[l\right]+\frac{\sigma_l}{\varphi\rho\sigma_\eta}$$

This defines k_{max}. It is higher than a very high value of k (with standard market risk-premium and standard error):

$$\mathbb{E}\left[l\,|l\geq k_{max}\right]=\mathbb{E}\left[l\right]+\frac{\sigma_l}{\varphi\rho\sigma_\eta}>\mathbb{E}\left[l\right]+\frac{\sigma_l}{\varphi\sigma_\eta}=\mathbb{E}\left[l\right]+20\sigma_l$$

Let's turn to equilibrium capacity:

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

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

$$g\left(k\right)=(V-c)\int_k^{+\infty}f\left(l\right)dl-(V-c)\,\varphi p\left\{\int_k^{+\infty}l f\left(l\right)dl-\mathbb{E}\left[l\right]\int_k^{+\infty}f\left(l\right)dl\right\}$$

$$\frac{\partial g}{\partial k}\left(k\right)=-\left(V-c\right)f\left(k\right)+\left(V-c\right)\varphi pkf\left(k\right)-\left(V-c\right)\varphi p\mathbb{E}\left[l\right]f\left(k\right)$$

$$\frac{\partial g}{\partial k}(k) = -(V-c) f(k) \{1 - \varphi p (k - \mathbb{E}[l])\}$$

$$\frac{\partial g}{\partial k}(k) < 0 \Leftrightarrow 1 - \varphi p (k - \mathbb{E}[l]) > 0$$

The range of values for which the derivative of g is negative is $\left[0, \hat{k}\right]$ with $\hat{k}$ given by the following equation :

$$1 - \varphi p \left(\hat{k} - \mathbb{E}[l]\right) = 0$$

$$\hat{k} = \mathbb{E}[l] + \frac{1}{\varphi p}$$

We get $\hat{k} > k_{max}$. So for the range of admissibles capacity values $[0, k_{max}]$, $\frac{\partial g}{\partial k}(k) < 0$.