DECARBONIZING THE ELECTRICITY SECTOR EFFICIENTLY REQUIRES A CHANGE OF MARKET DESIGN

Financing long-term investment in hybrid markets
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Document de travail

MAIN MESSAGES

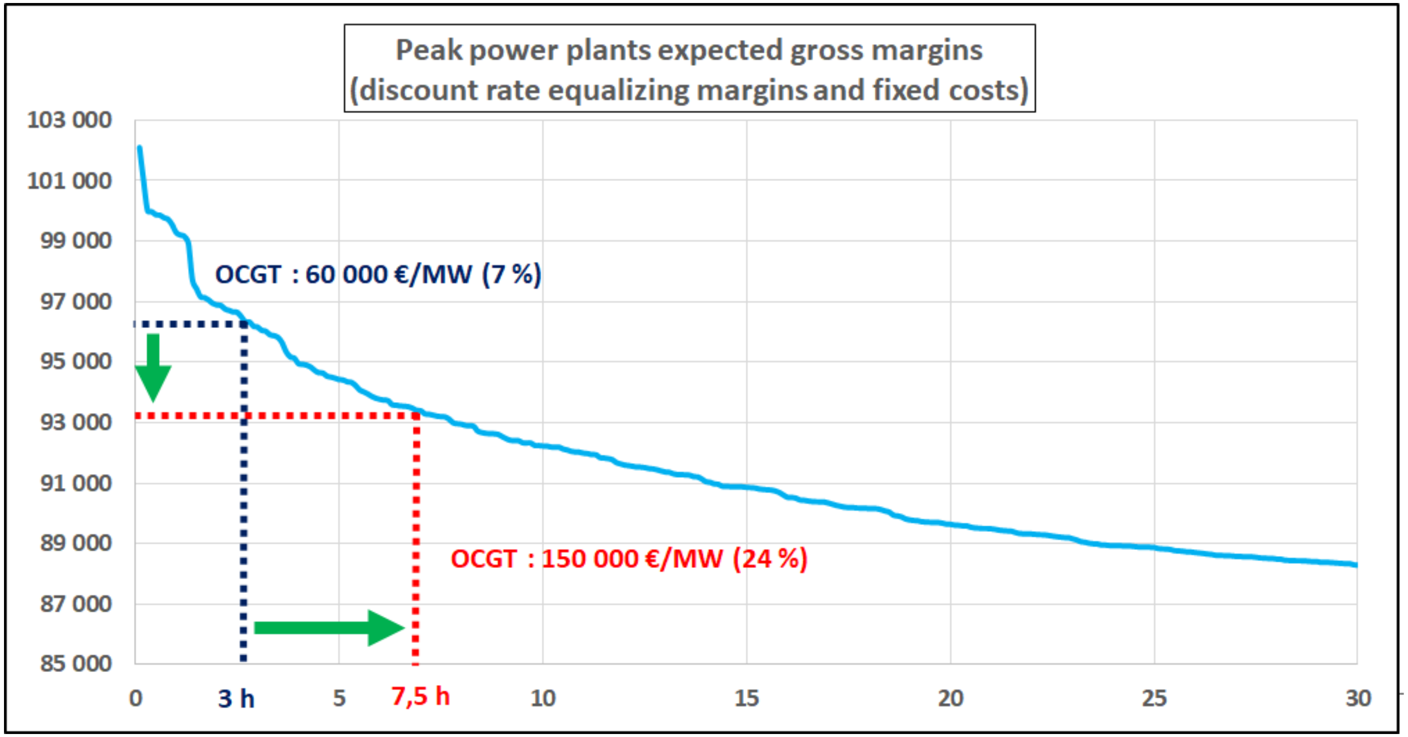
- **Decarbonizing the electricity sector in an Energy-Only market will result in higher financing costs**
  - Low carbon technologies (RES, Nuclear, etc.) have mainly fixed costs and low or zero variable cost
  - With the closure of fossil-fuel power plants, wholesale prices will be very low most of the time, since the price will bet set by the variable cost of low carbon technologies
  - Gross margins will be more volatile, leading to a higher cost of capital for investment

- **A long-term guaranteed price (such as a CfD), lowers the volatility of margins and the cost of capital. As a consequence, the average cost of production is lower**
  - This is true for all low-carbon technologies
  - Achieving carbon neutrality will thus necessitate the introduction of long-term price signals in complement of the short-term electricity market

- **Simulations with France load demand datas (2006-2015) allow to quantify the impact**

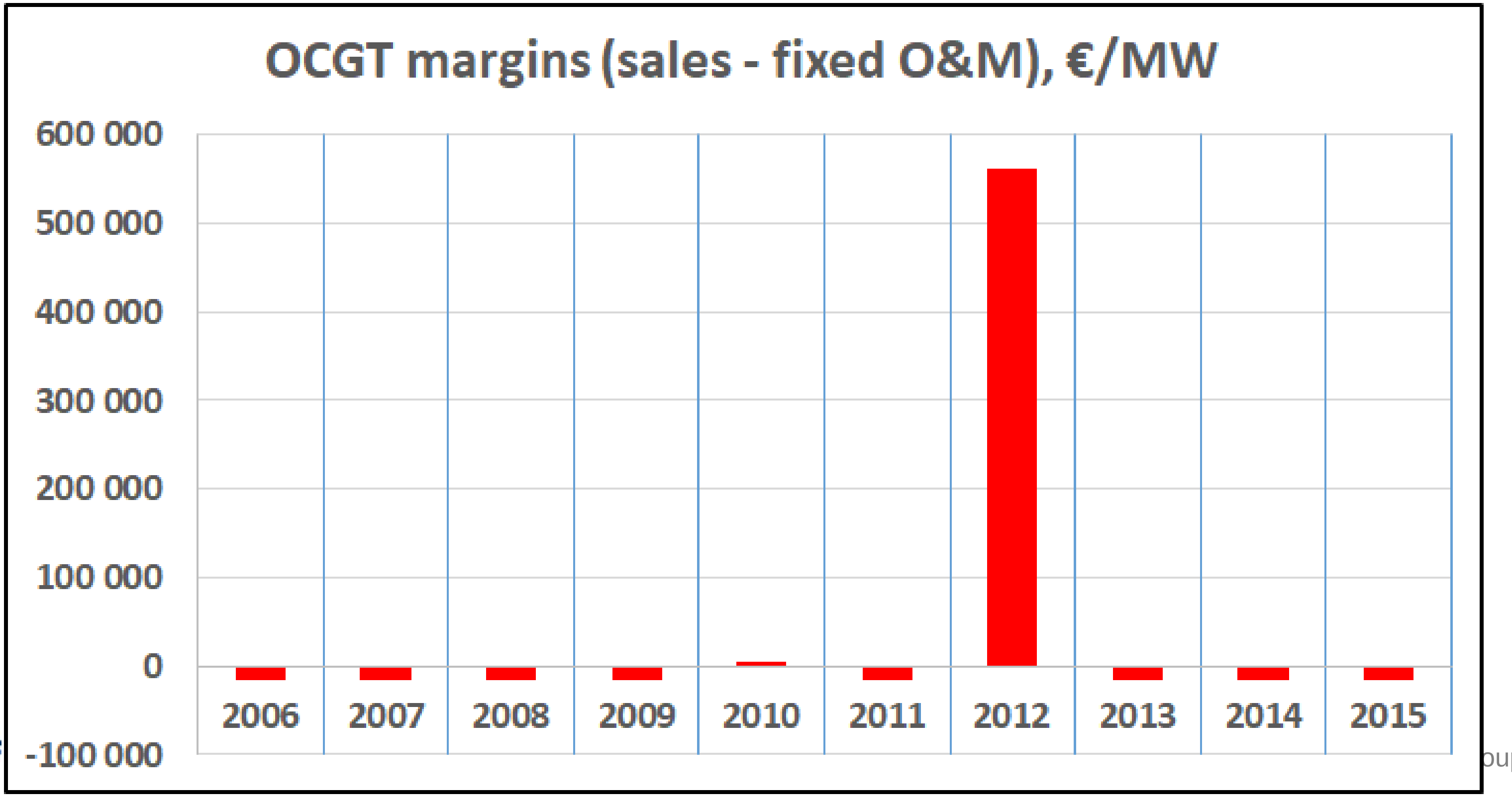
THE ISSUE WITH HISTORICAL ANALYSIS

- **Group A has shown that past investments were not profitable, but very broadly two possible explanations :**
  - (1) Risk under-estimated by companies and / or (2) Overcapacities
- **What would have happened if less capacities installed, leading to higher prices ?**
  - Peak power plant, for example : with less capacities, higher expected margins
  - Price = VOLL (20 000 €/MWh) when demand is higher than total installed capacity



A FIRST PICTURE OF RISK FOR PEAKERS

- **Net margins (sales minus fixed O&M) for a peak power plant, if the french Security of Supply standard is respected (an expected 3 hours of load-shedding)**
  - Only two years (2010 & 2012) where the power plant actually generates electricity
  - Does 7 % seem like a fair return for such a level of risk ?
    - Losses for 8 years out of 10, very high margins for 1 year



THE OPTIMAL TECHNOLOGY MIX

- **One way to disentangle the two effects is to calculate the optimal mix**
  - As in generation capacity expansion models, assuming no existing capacities
  - Since the probability distribution of load demand is known with certainty for the lifetime of power plants, there are no errors about expected consumption growth
  - We study only explanation (1), but, of course, reality is more messy and forecast mistakes do happen …

- **The optimal mix is a perfect competition model**
  - Each power plant sells its production on the wholesale market every time the wholesale price is higher or equal to its variable cost
  - No other revenues, no consumers portfolio to serve, every power plant act like an independant producer
  - Equilibrium : expected gross margins = fixed costs (no more, no less) = annuity + fixed O&M
  - Without storage in the mix, we can use a load duration curve to compute equilibrium capacities

THE COST OF CAPITAL

- **The discount rate should reflect financial risk, ie the volatility of gross margins**
  - A discount rate is needed to compute the annuity equivalent to investment costs

$$\boldsymbol{Annuity = Investment\ cost \times \frac{r}{\left(1 - \frac{1}{(1+r)^n}\right)}}$$

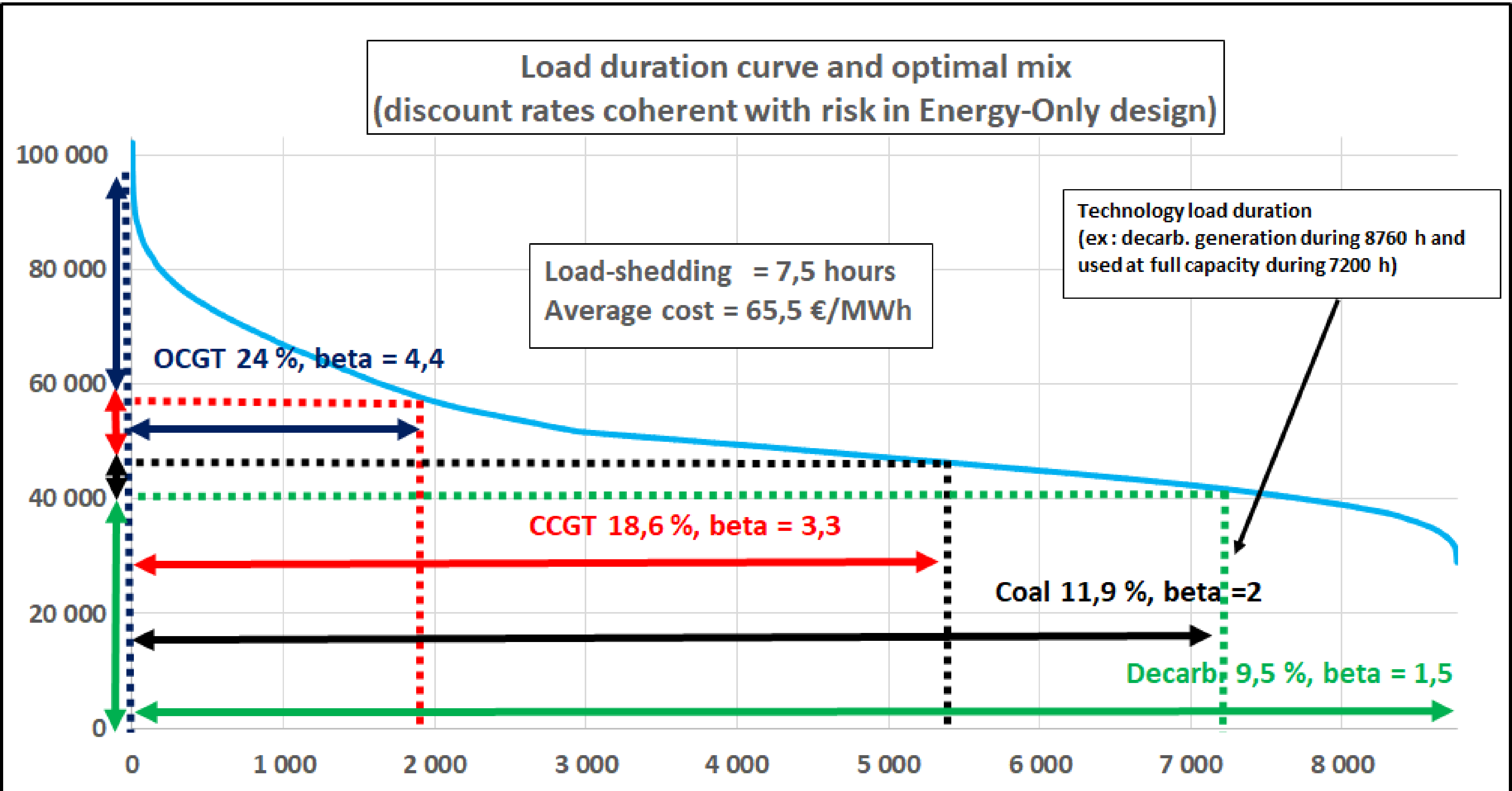
- **One way to do this is to compute the discount rate with the CAPM**
  - For asset i, the expected return should be :

$$\boldsymbol{E[r_i] = r_0 + \beta_i(E[r_m] - r_0)}, with : \beta_i = \frac{cov(r_i, r_m)}{var(r_m)}$$

- **This is the rate of return asked by investors, given the risk profile of the asset : it is a cost for a power plant developer, the cost of capital (here asset-betas)**
  - The higher the risk, the higher the rate of return demanded (if correlation > 0)
  - => A high and positive beta (for the market, beta = 1)
  - The higher this rate, the higher expected gross margins must be at equilibrium, which means less capacities installed

OPTIMAL MIX WITH DISCOUNT RATES COHERENT WITH RISK IN EO DESIGN

- **ERP = 5 %, risk-free rate = 2 %, load demand probability distribution built on load demand data in France (2006-2015)**



ENERGY-ONLY AND THE COST OF CAPITAL

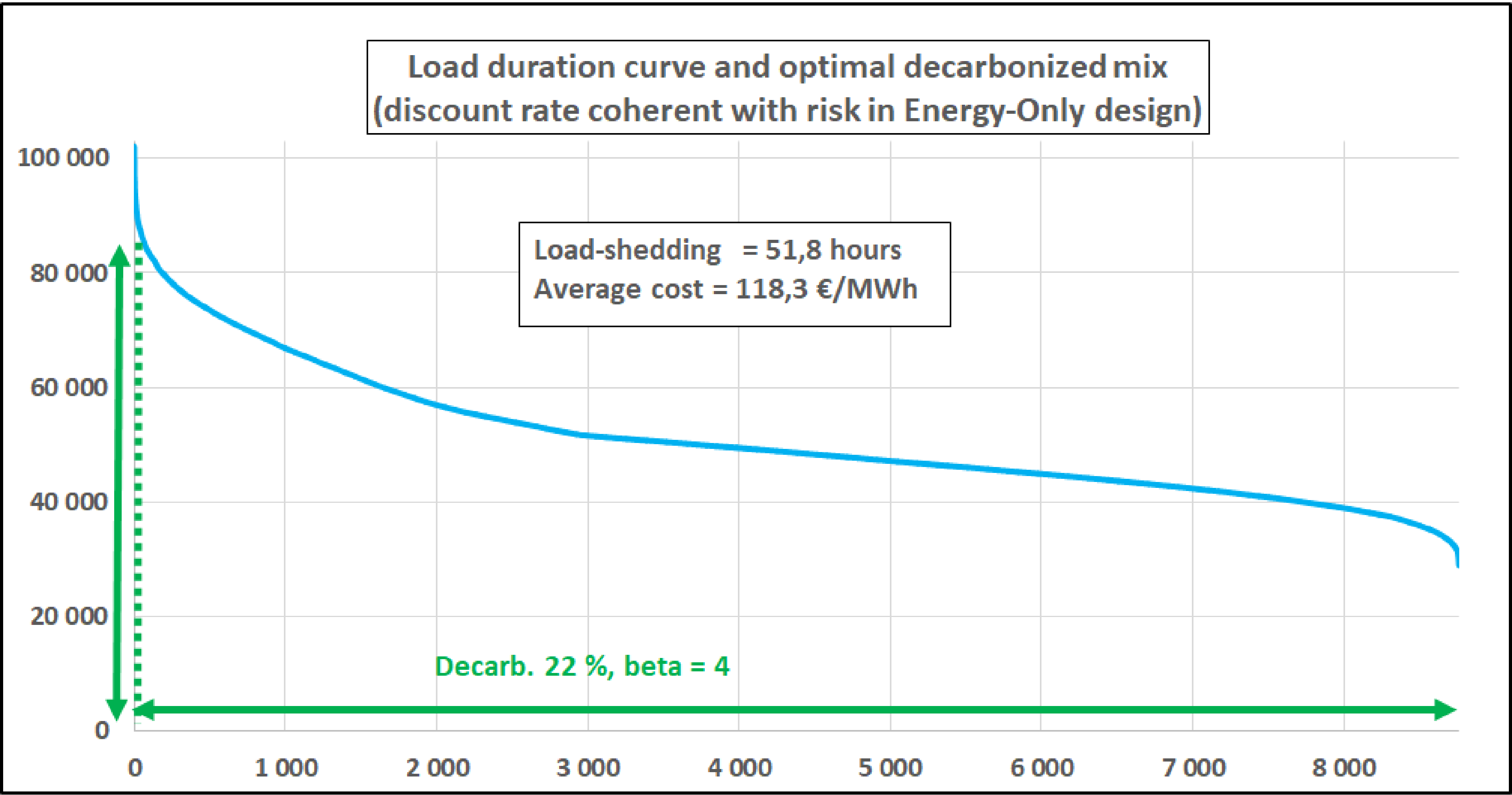
- **We find higher discount rates than usual values (~ 7-8 %)**
  - Load-shedding is higher than the SoS standard (7h30), since financial risk for a peak power plant is very high (asset-beta = 4,4)
  - The lower a technology in the merit order, the lower its equilibrium cost of capital : margins are less volatile

- **Decarbonized technology : fixed costs and lifetime of offshore wind (BP RTE 2017), but assumed perfectly dispatchable**
  - Baseload generation possible with a zero variable cost
  - Only meant as an illustration of non-emitting technologies whose costs are mainly fixed

- **In an Energy-Only market, decarbonizing the mix will increase the cost of capital for low carbon technologies by suppressing inframarginal rents**
  - The risk profile becomes nearly equivalent to that of a peak power plant (see next slide)
  - The carbon price no longer has an impact on inframarginal rents

OPTIMAL DECARBONIZED MIX WITH DISCOUNT RATE REFLECTING EO DESIGN RISK

- **Decarbonizing the mix, the cost of capital of the non-emitting technology becomes equivalent to the cost of a peak power plant**



DECARBONIZATION AND ENERGY-ONLY

- **In our previous example, the cost of production is raised significantly**
  - By more than 80 % compared to the optimal mix with endogenous discount rates

- **Intermittency of variable renewables is not the issue here, the increase in financial risk is**
  - In the case of a peak power plant, the return is either negative, with a high probability, or extremely positive, but with a very low probability
  - The previous chart is the same if there is zero variable RES or a high share
  - While decarbonizing the mix, the risk profile of other technologies becomes similar as recently noted by Joskow (2021)

- **The issue exists for all low carbon technologies, including renewables**
  - For variable renewables it should remain true, even if they are harder to modelize
  - Wind Europe has been asking that fixed price contracts remain used in order to keep the cost of capital low, at the same time that it has explained such contracts are not a subvention

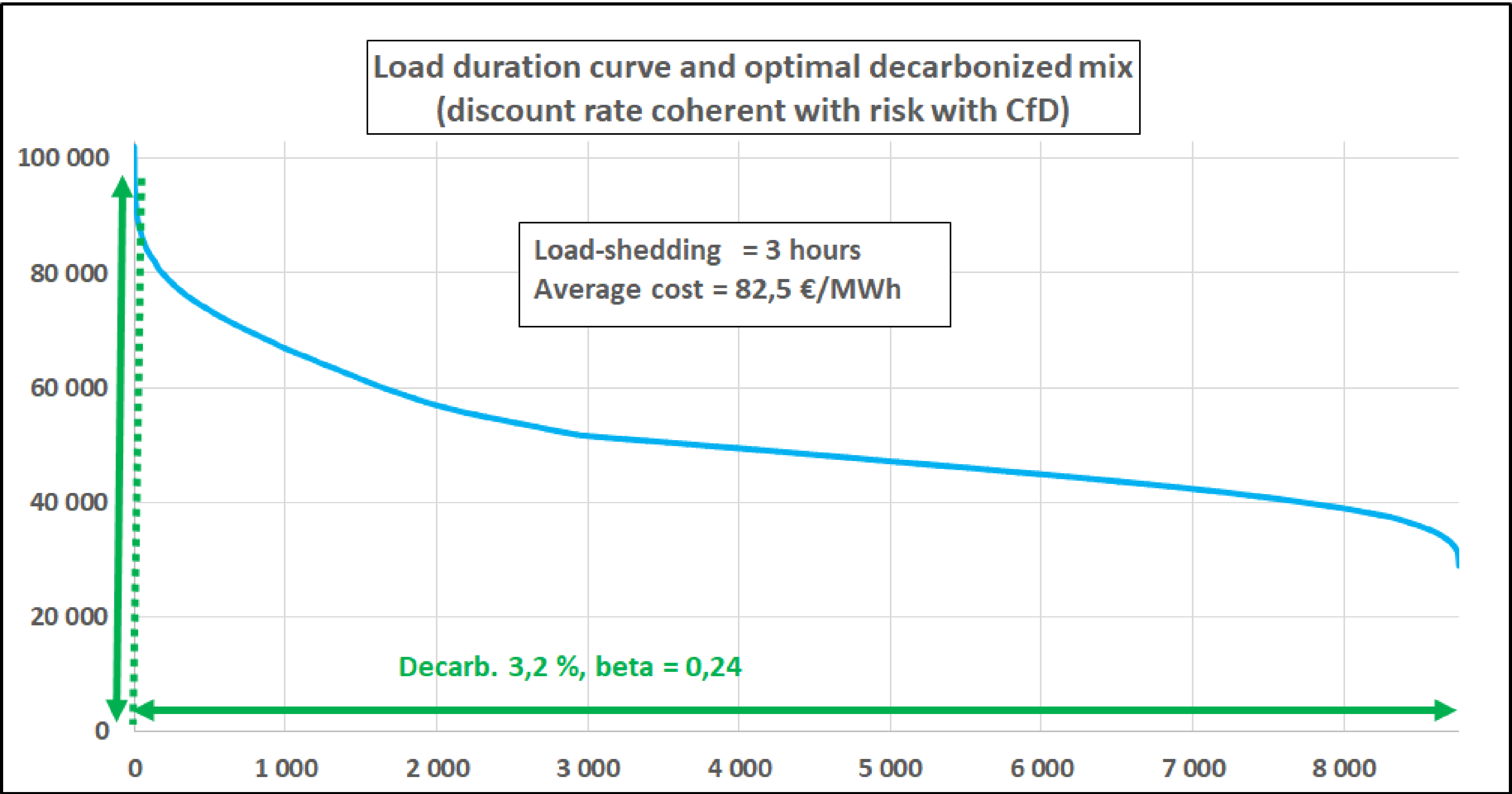
DEMAND SIDE RESPONSE

- **Demand response allows high prices to appear outside of load-shedding episodes, and thus lowers the cost capital of the low carbon technology, but the impact is limited**
  - Assumptions : 3 hours of load-shedding with VOLL equal to 20 000 €/MWh, then DR at 1 000 €/MWh whenever needed
  - Results : 730 hours of DR, cost of capital equal to 16 %, average cost of 90 €/MWh
  - Equivalent to 20 GW of DR available, without taking into account its costs of development
  - Some forme of DR is necessary to balance supply and demand in the short-run. It is possible to obtain it through an efficient tariff without exposing consumers to spot prices

- **We could also assume an elastic demand, but it does not radically alter the conclusions**
  - A linear elastic demand decreases the risk for the decarbonized technology, but not by enough to prevent a high cost increase when decarbonizing in an EO market
  - An electricity elastic demand is far from being possible today …

OPTIMAL DECARBONIZED MIX WITH DISCOUNT RATE REFLECTING CFD RISK

- **The mix is completely decarbonized, respects the SoS standard and has a lower average cost than in EO**



CONTRACT FOR DIFFERENCE AND DECARBONIZATION

- **In the previous case with a CfD, the decarbonized technology does not have a very high load factor**
  - The CfD strike price is set such that installed capacity allows the SoS standard to be met
  - Some power plants are used for mid-merit and peak generation
  - Different CfDs could be used, one for mid-merit-/peak ; and one with a lower strike price for baseload generation, thus allowing a lower average cost for consumers

- **But it is certainly better to introduce some DSR in order to install less capacities**
  - With the discount rate indicated (3,2 %), installed capacity without DSR should be lower than in the previous slide, with 19 hours of expected load-shedding and an average cost of 77,1 €/MWh
  - With 3 hours of expected load-shedding and 320 hours of DSR à 1000 €/MWh, an average cost of 66 €/MWh can be reached (not taking into account the cost of DSR deployement). The discount rate is slightly lower at 3,1 %

THE NEED FOR ANOTHER MARKET DESIGN

- **There is an issue of « missing markets » (Newbery 2016 & 2019), preventing risk sharing between producers and consumers**
  - Long term contracts prevent the increase in the cost of capital that decarbonizing the mix could induce -> hybrid market
  - Consumers benefit from a lower average (expected) cost
- **The problem of risk is added to the « missing-money » problem**
  - Missing-money is not modelized here since we assume the price of electricity can be as high as the VOLL when capacity is lacking
  - In practice, such prices do not seem to happen (Joskow 2021) : a CRM is a solution in the short to medium-run, with the definition of a security of supply standard
  - In the long-run, a new market-design is needed
- **Can storage alter that picture ?**
  - In a decarbonized mix, electricity storage may induce prices higher than the variable costs of low carbon technologies when load demand is low. But will it be enough ?
  - However, interseasonal storage may have a prohibitive cost (losses for electricity stored in summer for a use in winter)

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