Analysis of hurdle rates for Belgian electricity capacity adequacy and flexibility analysis over the period 2024-2034

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Abstract:

Adequacy and flexibility analysis for the Belgian electricity grid uses a simulation-based approach to evaluate the willingness to invest in new or existing electricity generation capacity. Under this framework, the investment takes place when the expected return exceeds the investment project's hurdle rate, which is set equal to the cost of capital of a reference investor plus a hurdle premium. The latter serves as a cushion to compensate for the deviation of the project's cost of capital from the reference investor's cost of capital based on the predicted project risk under the base scenario, and the model and policy risk related to alternative scenario outcomes. In this paper, we revisit the framework from the viewpoint of investments leading to capacity availability in 2024-2034.

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1. Introduction

Will there be sufficient investment in electricity capacity in Belgium to ensure security of supply ("keep the lights on") over the next decade? To answer this question, Elia publishes every two years a detailed ten-year adequacy and flexibility analysis for the Belgian electricity system.[2] Also at European level, similar analyses are done. In particular, the European Network of Transmission System Operators (ENTSO-E) is mandated by European legislation to make a European Resource and Adequacy analysis.

The adequacy and flexibility analysis uses simulation methods to determine the extent of capacity needed to maintain security of supply. If a capacity need is identified, an economic viability check should be performed on existing and new capacity for different technologies to see whether they would be viable in the market with the current market design and under the given hypotheses. Within the framework, it is assumed that an investment takes place when the expected return exceeds the project's hurdle rate. The calibration of the expected return is fully data-driven. It takes as input the distribution of inframarginal rents of a technology, together with the costs, and computes the expected return as the mean outcome of a large number of simulated project returns. Also the hurdle rate is to a great extent calibrated in a data-driven way. It is based on the WACC of the reference investor, and a premium per technology that reflects the differential in risk as shown in the simulation analysis for different scenarios.

The goal of this report is to propose a calibration of the investment parameters to be used in the 2024-2034 adequacy and flexibility analysis. The methodology used is the same as Boudt (2021). Changes in the parameter values reflect a change in the economic conditions as revealed in macro-economic variables and the distribution of inframarginal revenues for the investment technologies.

2. Definitions

2.1. Internal rate of return, hurdle rate determinants and cost of capital modelling

Helms et al. (2020) and Boudt (2021) describe the use of expected returns and hurdle rates to decide on investing in electricity capacity when the expected internal rate of return exceeds the so-called hurdle rate (Helms et al., 2020). The hurdle rate is thus the threshold τ that the expected internal rate of return of the project needs to exceed for the project to be economically viable.

Economic viability: $E[R] \geq \tau$ = Hurdle rate

An investment is thus modelled as financially attractive when the expected project return exceeds the hurdle rate, defined by ACER (2020) as the "minimum rate of return required by fund providers (shareholders and/or creditors) to finance investment in the reference technology in the considered geographic area". ACER (2020) refers to the hurdle rate as the Weighted Average Cost of Capital ($WACC$). It then consists of a bottom-up calculation in which first the cost of equity (CoE), cost of debt (CoD), and gearing ratio (g, i.e. percentage of debt-based funding) of the project are defined. In addition the corporate tax rate (t) and expected inflation (i) over the project's investment horizon are needed. All parameters are then aggregated into a (pre-tax and real) value of the WACC given by:

[2] See https://www.elia.be/en/electricity-market-and-system/adequacy/adequacy-studies

$$WACC = \frac{1 + \left[CoE \cdot \frac{1-g}{1-t} + CoD \cdot g\right]}{1+i} - 1$$

where:

- CoE: Cost of equity of the project
- CoD: Cost of debt of the project
- g: Gearing ratio of the project
- t: Tax rate
- i: Expected inflation

When these parameters are known, the project WACC can be directly computed.

Under the simulation-based decision framework, the CoE, CoD and g of the project over the analysed horizon are not known. Instead, based on historical data, one can make a good approximation of the cost of equity, cost of debt and gearing ratio of a potential reference investor. Denote these by CoE^* , CoD^* , and g^* , and let $WACC^*$ be the WACC of the reference investor. The deviations between the reference investor's parameters (CoE^* , CoD^* , and g^*) and the project parameters (CoE , CoD , and g) lead to a hurdle premium that differs across projects:

Economic viability: $E[R] \geq \tau$ = Hurdle rate = $WACC^*$ + hurdle premium

Since the project risk deviates from the risk profile of the reference investor, the presence of a hurdle premium is needed by construction. Brealy et al. (2020) note the approach of adding a (relative) project adjustment to a reference cost of capital is easier than estimating each project's cost of capital from scratch.

Boudt (2021) recommends that, for the scenarios and technologies that are similar to the ones considered in Elia (2021), and when the investment horizon is at least three years, the minimum value of the hurdle premium is the one described by Helms et al. (2020), namely 5% (nominal value).[3] [4] This minimum hurdle premium is needed to compensate for the fact that investors consider that the risk that the actual returns deviate from the expected returns (as computed under the base scenario used in the economic viability assessment) is higher than for the projects for which they use the reference WACC as hurdle rate. The reference WACC is based on the required return for listed companies by investors who can diversify that company risk in their portfolio. For the specific project risk, there are less diversification opportunities and clearly also less liquidity. This concentration and liquidity risk imply a premium for all investments considered. The 5% is the lower bound for the projects and technologies considered.

In addition to the minimum bound, Boudt (2021) also assumes an upper bound on the hurdle rate for the projects considered in his report, namely two times the (real and pre-tax) WACC of a fully-equity funded project with a CoE equal to the reference CoE.[5]

[3] Helms et al. (2020) note that "an additional hurdle premium of 5% or more on the WACC" is common in many industries.

[5] If the hurdle rate is higher than twice the CoE^* , the analyst doing the simulation analysis should exclude the project from the evaluation.

Based on the above, we have the following interval for the hurdle rate of a project in electricity capacity in Belgium with a significant initial capex investment and uncertain inframarginal rents over an investment horizon of three years and more:

$$\text{Hurdle rate } \tau \in \left[WACC^{*} \;+\; \left(\frac{(1+5\%)}{(1+i)} - 1\right),\; 2 \cdot \left(\frac{1+\frac{CoE^{*}}{1-t}}{1+i} - 1\right) \right]$$

$$\text{Hurdle premium} \in \left[\;\left(\frac{(1+5\%)}{(1+i)} - 1\right),\; 2 \cdot \left(\frac{1+\frac{CoE^{*}}{1-t}}{1+i} - 1\right) - WACC^{*} \right]$$

The interval approach to defining the hurdle rate is needed to account for the variation in risk between the investment projects considered. All other things being equal, when two projects have the same expected return, an investor prefers the one with the lowest hurdle rate.

The interval approach corresponds visually to a risk barometer. The utmost left point on the risk barometer corresponds to a project with pre-tax nominal hurdle premium of 5%.

Compared to the hurdle rate of this base project, the hurdle rate of a project increases when:

1. There is a decrease in the gearing ratio (higher reluctance of banks to provide debt financing), which could vary according to the risks exhibited by the kind of project, e.g. the technology considered
2. There is an increase in the project return variance and downside risk as quantified assuming the (non-normal) distribution of inframarginal rents under the base scenario is correct. The reference simulation setup is the one considered to be the best estimate representation of reality (among the considered setups) assuming continuity of energy policy, consumer and producer preferences, continued market design (incl. no market intervention in terms of imposing price caps or other kinds indirectly affecting the occurrence of high prices).
3. There is a high perceived likelihood of alternative scenarios leading to lower expected return and/or higher project return variance and downside risk than what is modelled under the base scenario. Examples of expected losses when the actual state of the world is not as described by the reference model are:
    a. Changes in policy (e.g. uncertainty about implementation of EU Green Deal) affecting the future capacity mix and resulting energy prices
    b. Impact of policy decision on the profitability of certain technologies (e.g. support schemes for Renewable Energy Sources (RES), a price or profitability capping for RES in scenarios of high gas prices, or limitations on fossil fuel-based generation, additional requirements on future gas mix, etc.).
    c. Sustainability of price spikes in the reference setup and perceived risk that actual prices may be directly or indirectly capped.
4. There are less opportunities to mitigate the project risk by hedging and/or there is an increase in the cost of financial and operational hedging. For instance, for baseload and merit order technologies forward products are more appropriate hedging instruments than for technologies with high activation costs.

The minimum hurdle premium might decrease when:

1. The uncertainty of the project return is exclusively driven by short term risk factors. This is the case for investments with a horizon less than three years for which we recommend setting the minimum hurdle premium to 0%.
2. Market design is substantially changed, resulting in a more stable revenue stream for investments in the energy market (e.g. implementation of a capacity remuneration mechanism with fixed capacity payments).

2.2. Calibration of the reference WACC and hurdle rate interval in practice

For the reference cost of equity we recommend to follow the guidelines of ACER (2020). This includes the use of the Capital Asset Pricing Model (CAPM) for the cost of equity calculation.[6]

According to ACER (2020), we have:

$$CoE^* = r_f + \beta \cdot ERP + CRP,$$

where r_f is the long-term risk-free rate, β is the systematic risk of the reference investor, ERP is the equity risk premium and CRP is the country risk premium.

For long-term investment in electricity capacity in Belgium over the period 2024-2034, a reasonable calibration is to set the nominal risk-free rate at 1.4% (as based on the average long term interest rate for Germany in June-July 2022).[7] Following Damodaran, the country risk premium of Germany in July 2022 is 0% while it is 0.23% for Belgium. The general market equity premium is at 6.01%.[8] Using a set of representative utilities and energy companies, the equity beta for a reference investor is estimated at 0.83.[9] Given these parameters we can compute the nominal cost of equity:

$$CoE^* = r_f + \beta^* \cdot ERP + CRP = 1.4\% + 0.83 \cdot 6.01\% + 0.23\% = 6.693\%.$$

The cost of debt and gearing ratio can be estimated by analysing the balance sheet of prospective investors and adjusting for the period. A reasonable number here is that $CoD^* = 5\%$ and a gearing ratio of 44%. Assuming a corporate tax rate of 25% we have that the nominal WACC of the reference investor equals

$$\text{Nominal WACC} = CoE^* \cdot \frac{1-g^*}{1-t} + CoD^* \cdot g^* = 7.197\%$$

The expected inflation is set to 2.2%.[10] Assuming a corporate tax rate of 25% we have that the real $WACC^*$ = 4.89%:

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[6] Violations of the CAPM assumptions (due to exposure to other priced risk factors and the non-normality of the project returns among others) need to be accounted for in the hurdle premium.

[7] See https://www.ecb.europa.eu/stats/financial_markets_and_interest_rates/long_term_interest_rates/html/index.en.html

[8] https://pages.stern.nyu.edu/~adamodar/pc/datasets/ctrypremJuly22.xlsx

[9] The equity beta, the gearing and the cost of debt parameters take into account publicly available data from energy market players in Europe. Detailed calculations are available from the author.

[10] See https://www.ecb.europa.eu/stats/ecb_surveys/survey_of_professional_forecasters/html/table_hist_hicp.en.html

$$WACC^* = \frac{1+\left[CoE^* \cdot \frac{1-g^*}{1-t} + CoD^* \cdot g^*\right]}{1+i} - 1 = \frac{1+\left[7.197\% \cdot \frac{1-0.44}{1-0.25} + 0.05 \cdot 0.44\right]}{1+2.2\%} - 1 = 4.89\%$$

The project WACC equals the reference WACC plus a hurdle premium. Under the framework described in Subsection 2.1, we set the minimum hurdle premium to $\frac{1+5\%}{1+2.2\%} - 1$ = 2.74% leading to a minimum hurdle rate of 7.63%. The maximum hurdle rate is $2 \cdot \left(\frac{1+\frac{6.70\%.}{1-0.25}}{1+2.2\%} - 1\right)$ = 13.16%.

Based on the above calibration, the total hurdle rate for projects with an investment horizon of three years and more) is thus between 7.63% and 13.16%, implying a hurdle premium between 2.74% and 8.27%.

$WACC^* = 4.89\%$		Minimum hurdle rate = 7.63%	Hurdle rate of technologies (≥ 3 years investment) considered	Maximum hurdle rate = 13.16%

	Minimum hurdle premium = 2.74%	Hurdle premium of technologies (≥ 3 years investment) considered	Maximum hurdle premium = 8.27%

3. Taxonomy of technology-specific drivers of the hurdle premium

Investments in electricity capacity are not equal. They differ in terms of technology used, costs (capex, fixed operation and maintenance (FOM), variable costs), inframarginal rents, and economic lifetime. This heterogeneity leads to differences in hurdle premium across investment projects. This section establishes a taxonomy of determinants of the premium.

3.1. Calibration of the hurdle premium per technology using the distribution of returns obtained under the base scenario

Under the simulation framework, we can quantify the individual risk of each investment under the base scenario, which is the one considered to be the best representation of reality (among the considered setups) *assuming continuity of energy policy, consumer and producer preferences and no market intervention affecting the occurrence of (very) high prices.*

3.2. Calibration of the hurdle premium per technology by evaluating the "what if…" questions an investor may consider

The observed variability in the base scenario simulation setup ignores many risk drivers and is thus an underestimation of the perceived project (downside) risk. As such the return and risk evaluations under the base scenario are *ceteris paribus* numbers. Rational investors however do take into account the additional variability caused by deviations from the model assumptions

Below we provide a non-exhaustive list of important additional sensitivity analyses to perform in order to calibrate the hurdle premium of an investment project.

3.2.1. What if high price spikes are heavily discounted or subject to a perceived price cap?

While expected revenues could be simply represented by means of an average, it is relevant to consider the effect of high price spikes in such approach as – obviously – such price spikes are affecting the average project return significantly. What if investors tend to discount (or not consider at all) such price spikes in their profitability assessment due to risks attached to their occurrence or other reasons?

Such strike price is typically in the range of a few hundreds of euros per MWh when looking at similar schemes in Italy and Ireland and also when looking at the proposal recently put forward by Elia. In this respect market parties[11] have for instance indicated that any prices above 300 €/MWh are less likely to be considered in their revenue assessment.

3.2.2. What if public policy imposes a ceiling on the rate of return per project

Investors may anticipate the possibility that, in the event of very favorable outcomes in terms of inframarginal rents, policy makers may decide to redistribute the surplus by imposing an additional tax. Such a tax can take different forms. One way to model this is the consider a scenario in which the government limits ex post (at the end of the investment) the return by imposing a ceiling on the project internal rate of return and taxing away the excess return with respect to that upper bound. When the investor takes such a tax into account this will lead to a lower expected return. Under the simulation approach taken, the return impact of such a bound can be quantified. Technologies for

[11] FEBEG presentation of the Task Force of 13.06.2019.

which the drop in return is more substantial will in general require a higher hurdle rate when the perceived probability of such a tax increases.

3.2.3. What if the merit order changes?

The determination of which capacities deliver energy at a particular moment, is based on the so-called "merit order" principle. The effect of merit order changes may significantly affect the business case of an investor. Merit order changes could be driven by various factors, such as fuel price evolutions, CO_2-prices, capacity mix (domestically, but also abroad due to increased interconnection levels throughout Europe), etc. This is essentially part of scenarios taken into account by investors. Note that this can be clearly driven by policy as well (e.g. measures impacting carbon prices, measures (e.g. taxes) on fuels, etc.).

To illustrate the effect such change could resort, the calculations in the proof of concept compare a coal before gas with a gas before coal scenario building on the dataset used throughout this study.

3.2.4. What if a technology becomes obsolete?

More radically than a merit order change, would be considering what the effect on profitability would be if a technology becomes obsolete over time resulting for instance in (close to) zero revenues in the last 5 or 10 years of its initially assumed economic lifecycle. While being more extreme, it illustrates well the effect (changing or reinforcing a) policy may have especially if 'becoming obsolete' is not the result of business-as-usual evolutions in a sector but rather the result of market intervention or policy measures such as decarbonisation (e.g. coal units are becoming obsolete due to high CO_2 emissions). While the objectives of such policy from a societal perspective may be well justified, in some cases it might undeniably affect individual investments from the past.

3.2.5. What if we go from inadequate to adequate?

Throughout this study, the base scenario corresponds to a situation described in Elia's 2021 Adequacy & Flexibility study where the economic viability of technologies based on energy market revenues (including ancillary revenues) only is at a tipping point. The already installed capacity tends to be profitable but adding more investments to the system would result in a loss. In this scenario, it was observed that the situation was however not yet considered adequate as the reliability standard was not yet met. If the system would be complemented with extra capacities making the scenario adequate, that would have reduced average price levels and particularly the number of price spikes.

Therefore, adding to the uncertainties the investors are facing, there is the issue of cannibalization. A single new unit might put downward pressure to electricity prices, reducing the value of new capacity once operational, hence reducing the incentives to invest in an energy only market context. Market parties largely depend on each other's choices, but lack perfect insight in these decisions of other investors increasing the uncertainty due to this lack of coordination between investors.

In addition, it is likely that investors would believe that political measures would be taken in order to ensure an adequate scenario in which the reliability standard would be met. If an investor would take such political intervention as hypothesis, he will build its investment case on an adequate scenario, i.e. with reduced average price levels and lower number of price spikes, negatively affecting its rate of return.

The equilibrium may be fragile. Adding 'deus ex machina' (e.g. by means of targeted intervention) capacity to the system and the market, may also directly affect profitability of all other projects in the market (that would be excluded from the intervention).

3.2.6. What if fixed operations and maintenance (FOM) costs are higher

Under the base scenario, costs are deterministic. In practice, there is a risk that costs are higher than expected. To study the sensitivity of the results to the level of the costs, it is recommended to consider the return impact of alternative calibration of the costs, such as for example CAPEX and FOM.

4.3. Additional considerations for the calibration of the hurdle premium per technology

The above considerations have stressed the potential variability of the project returns. In practice, the investor may use operational and financial hedging to reduce the variability at the level of the investment portfolio. The hurdle premium across technologies needs to be differentiated taking into account the possibility for hedging. For instance, for baseload and merit order technologies forward products are more appropriate hedging instruments than for technologies with high activation costs operating at fewer moments.

The impact of model and policy uncertainty increases with the horizon of the project. The impact of the horizon increases when the investment involves a high CAPEX. All other things being equal, technologies with a longer investment horizon and a high CAPEX require a higher hurdle premium than those with a shorter horizon.

For some technologies, there is uncertainty about the cost and time needed to install the capacity in Belgium. The higher this uncertainty, the higher is the hurdle premium.

The perceived regulatory instability may also differ across technologies. There is a substantial option value of waiting when investors expect a change in market design that results in a more stable revenue stream for investments in the energy market (e.g. implementation of a capacity remuneration mechanism with fixed capacity payments or the introduction of support measures for investments in sustainable technologies).

The hurdle premium needs also to adjust for differences in the gearing ratio of the investment project as compared to the one assumed in the reference WACC calculation. In terms of the relative adjustment between investments, one can expect that the relative differences in gearing ratios are related to the estimated risk profile: the more risky, the lower is the expected gearing ratio.

In addition to the unconditional risk and return characteristics of the investment, investors may also have state-dependent preferences possibly related to operational hedging or sustainability considerations. Specifically, they may attach a preference for investments that yield revenues in a state of high prices. The presence of such state preferences would then imply to reduce the premium compared to what would be obtained by only considering the unconditional distribution of returns. Such state-dependent preferences seem to be especially important for the evaluation of an investment in demand side management.

4. Application of hurdle rate decision framework to the investment decision considered in the economic viability assessment

This section provides a proof of concept of the methodology outlined in the previous sections and described in Boudt (2021). The investment decisions that we model are inspired by Elia's 2019 and 2021 Adequacy & Flexibility study. The used distributions of inframarginal rents are not necessarily representative of a current investment case.[12] We first describe the simulation setup. We then compute the expected return and risk under the base scenario. Next, we quantify the impact on expected return and risk of alternative scenarios. We conclude with a tentative conditional calibration of the hurdle premium based on a combination of quantitative and qualitative assessments.

4.1. Design

4.1.1. Assumptions about investment project under the base scenario

We now illustrate the simulation-based decision analysis for 18 investment cases that differ in terms of technology used and yield a different distribution of inframarginal rents. They also differ in terms of lifetime (that we denote by K years) and costs (both the initial $CAPEX$ and the yearly FOM cost). All technologies considered require substantial $CAPEX$ and have uncertain cashflows over an investment horizon of three years and more (justifying a minimum nominal pre-tax hurdle premium of 5%).

The 18 technologies (their lifetime and related fixed costs used to illustrate the outcome) are as follows[13]

1. New CCGT (*K=20* years, CAPEX = 600 €/kW, FOM = 25 €/kW/y) represents the construction of a new Combined Cycle Gas Turbine with an installed capacity of at least 800 MW.
2. New OCGT (*K=20* years, CAPEX = 400 €/kW, FOM = 20 €/kW/y) represents the construction of an Open Cycle Gas Turbine with an installed capacity of at least 100 MW.
3. Existing OCGT (*K* =3 years, CAPEX = 0 €/kW, FOM = 20 €/kW/y) represents the costs related to a OCGT that is already operational and does not require refurbishment.
4. Refurbished OCGT (*K=15* years, CAPEX = 80 €/kW, FOM = 40 €/kW/y) represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
5. Existing CCGT (*K* =3 years, CAPEX = 0 €/kW, FOM = 30 €/kW/y) represents the costs related to a CCGT that is already operational and does not require refurbishment.
6. Refurbished CCGT (*K=15* years, CAPEX = 100 €/kW, FOM = 30 €/kW/y) represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
7. Old CCGT (*K* =3 years, CAPEX = 0 €/kW, FOM = 30 €/kW/y) represents the costs related to an old CCGT that is already operational and does not require refurbishment.
8. Refurbished old CCGT (*K=15* years, CAPEX = 100 €/kW, FOM = 30 €/kW/y) represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
9. New offshore (*K=15* years, CAPEX = 2300 €/kW, FOM = 80 €/kW/y) represents the construction of a new offshore wind installation.

[12] The specification of the best possible distribution reflecting the relevant income distribution of the investor is beyond the scope of this study.
[13] Compared to the previous study (Boudt, 2021), we now consider only investment projects with a duration of at least 3 years.

10. New onshore (*K=15* years, CAPEX = 1000 €/kW, FOM = 50 €/kW/y) represents the construction of a new onshore wind installation.
11. New PV (*K=15* years, CAPEX = 600 €/kW, FOM = 25 €/kW/y) represents the construction of a new PV solar installation. [14]
12. DSM300 (*K*=3 years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with a low activation price of 300 €/MWh.[15]
13. DSM500 (*K*=3 years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with an activation price of 500 €/MWh.
14. DSM1000 (*K*=3 years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with an activation price of 1000 €/MWh.
15. DSM2000 (*K=3* years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with an activation price of 2000 €/MWh.
16. PSP (*K=25* years, CAPEX = 900 €/kW, FOM = 30 €/kW/y) represents the construction of a pumped storage Plant.
17. Batteries 2h (*K*=15 years, CAPEX = 400 €/kW, FOM = 15 €/kW/y) represents the investment in a large-scale battery with 2h energy content.[16]
18. Batteries 4h (*K*=15 years, CAPEX = 750 €/kW, FOM = 15 €/kW/y) represents the investment in a large-scale battery with 4h energy content.

The cost related to the time to construct is assumed to be in the CAPEX calculation.[17]

4.1.2. Assumptions about state of the market the base scenario

As in Elia (2021), we use simulated rents obtained under a model in which there is a maximum energy price at which the modelled market can clear. In the base scenario, there is a price cap at 3k€/MWh , which is considered as the reference price cap, as it corresponds to the price cap applied in the simulations by Elia (2021).[18]

The base scenario that we consider corresponds to a situation where the economic viability of technologies is at a tipping point. It can be considered as the equilibrium where based on energy market revenues investments were just profitable but adding more investments to the system would result in a loss. In this scenario, it was observed that the situation was however not yet considered adequate. In the base scenario gas is used before coal in the electricity generation merit order.

Compared to the inframarginal rent distributions used in Boudt (2020), we have that the EVA equilibrium is different: LOLE after EVA is now around 5 hours while this was around 10 hours in the previous study. A new climate data base has been used with more climate years with at least 1 hour of scarcity but the duration of the scarcity is shorter. Hence, when there is scarcity in a given year, the average duration of a scarcity period is less than in the previous study.

[14] The numbers represent a mix of solar installations with different sizes, taking into account the average costs of such PV installations.

[15] There is little information available regarding the cost of DSM. The FOM values of 50 €/kW/y for the DSM technologies is a proxy.

[16] See https://www.elia.be/en/public-consultation/20220506_public-consultation-on-crm

[17] An alternative approach is to increase the lifetime variable *K* and let the specification of revenues and cost depend on the time elapsed since the initial investment.

[18] There are alternative price cap modelling approaches that can be considered. One reference for this is https://www.acer.europa.eu/events-and-engagement/news/acer-reviews-rules-automatic-price-adjustment-mechanism-day-ahead-and

4.1.3. Merit order and extreme prices under the base scenario

Before presenting the simulation results, we first zoom in on two important drivers of the relative magnitude of project return risk: the merit order and the occurrence of extreme high prices over the simulation horizon.

The economic dispatch of different technologies in the electricity market, i.e. the determination which capacities deliver energy at a particular moment, is based on the so-called "merit order" principle. Based on the marginal costs offered by the different capacities available in the market, a supply curve can be conceived in function of increasing marginal costs. The electricity price for any given moment (e.g. on an hourly basis) is determined by the intersection between this supply curve and the demand curve. The higher the variable costs of the marginal technology (i.e. the most expensive technology that is still required to meet the electricity demand), the higher the electricity price for that given moment.

The technologies with marginal costs in the dataset are typically ranked as follows (with increasing marginal costs): renewable energy supply (wind and solar power) and baseload,, gas-fired units such as new CCGT, refurbished and existing CCGT, CCGT, OCGT (order of magnitude 30 to 100 €/MWh, depending on natural gas and CO_2 prices), DSM 300, DSM 500, DSM 1000 and DSM 2000 each corresponding to demand side management that can be activated at costs of respectively 300, 500, 1000 and 2000 €/MWh (those latter cost levels are typically linked to the opportunity cost of not consuming electricity). There is no marginal cost for large scale batteries and PSP.

While wind and solar power have the lowest marginal costs and typically come first in the merit order, they are intermittent resources, i.e. their availability is obviously fully dependent on the weather conditions.

The market revenues for the market clearing capacity, i.e. the last one selected setting the market price, cover only its marginal costs, while other capacities earn inframarginal rents (i.e. the difference between the electricity price and their marginal costs for a given technology). As a result, capacities with lower marginal costs receive inframarginal rents more often than capacities with a high activation price (e.g. DSM 2000). The investment case of such capacities with high activation prices depends therefore to a larger extent on the occurrence of price spikes. Stated otherwise, a contribution to the profitability of a capacity only takes place when the (spot) price on the market goes beyond the marginal cost of the considered capacity, i.e. when it is inframarginal. The higher the activation cost, the fewer hours with actual inframarginal rents, the more relevant it is that those more limited hours also actually occur. Hence, in some cases, profitability crucially depends on the occurrence of (very) high prices during only a handful of hours.

The fuel and CO_2 prices are key components of the marginal costs of several fossil fuel technologies. The higher the expected CO_2 or fuel costs, the higher the marginal costs of such technologies, which will affect its place in the merit order. Therefore, assumptions on CO_2 and fuel prices play a crucial role in the profitability of such assets. Also, given that these fuel and CO_2 assumptions affect the marginal costs of some technologies, these have an impact on the clearing price and thus on the inframarginal rents of other technologies.

In Belgium, very high prices, i.e. moments exhibiting significant inframarginal rents for many capacities, most often occur in case of cold periods during winter (increase of consumption due to heating and low solar power output as the peak consumption typically takes place in the evening when it is already dark outside). When also no or limited wind power is available, this also drives prices up as technologies further in the merit order are needed to meet demand. Note that cold spells are regularly accompanied by low wind generation, which can lead to the so-called "Dunkelflaute", characterized by no wind and little sun.

During such periods, the contribution of wind and PV to the electricity production is obviously very low. At these moments, the remaining need for electricity (which is already higher given the low temperatures) has to be filled by other technologies such as thermal generation, imports, storage (if not yet depleted) and market response. Given that more expensive technologies (i.e. higher marginal costs) need to be activated to meet electricity demand, the very high price spikes occur typically during these moments with low sun and wind output. As a consequence, the statistical distribution of the inframarginal rents for wind and solar installations are less impacted by the occurrence of price spikes as they are simply not able to capture those spikes due to lack of wind and sun at those moments.

The hurdle premium calibration should take into account the discussed differences of position in the merit order and differences of exposure to high prices across technologies.

4.1.3. Distribution of inframarginal rents under the base scenario

The below table and histogram plot describe the distribution of the yearly inframarginal rents for the technologies considered.

For the actual investment return analysis, the inframarginal rents need to be analyzed jointly with their costs and the horizon of the investment. This is the object of the next subsection. However, since the costs are fixed, it is useful to analyze the variability of the inframarginal rents to gauge differences in risk between the projects.

Consistent with the fact that DSM300, DSM500, DSM1000 and DSM2000 have the largest activation costs and they are last in the merit order, we find that there is every year 17%, 38%, 48% and 52% probability that these technologies are not activated resulting in a zero inframarginal rent. [19]

PV has the lowest variability. For PV, all inframarginal rents are between 37.28 and 83.61 €/kW with a standard deviation of 4.26 €/kW. Also wind has a relatively low standard deviation (12.26 and 17€/kW). For CCGT, OCGT and Coal CSS technologies, the maximum rent is above 500 €/kW. The low variability of Wind and PV is driven by their top position in the merit order book, on the one hand side, and by the fact that they have no upside variation in case of the extreme high prices at times where wind and PV are jointly non-available for capacity generation. This high probability of unavailability of solar and wind power during moments of high consumption causes the highest price spikes leading to the extreme high values in the inframarginal rents of the CCGT, OCGT, DSM and large scale batteries technologies.

The lower sensitivity of the yearly aggregate inframarginal rents of wind and PV to price spikes is also clear in terms of the almost negligible difference between their median and mean value, as opposed to the gap between median and mean inframarginal rents for all other technologies.

In case of price peaks, all technologies in the dataset are mostly activated to meet the energy demand, provided that they are available. This explains why all inframarginal rents are right-skewed and fat-tailed. Under a normal distribution, the skewness is zero (symmetry) and the kurtosis equals 3. Kurtosis values higher than 3 indicate fat tails. Note that for all technologies considered, the skewness and kurtosis differ extensively from their reference value under the normal distribution, indicating

[19] Note that there is time diversification. Under the assumption of independently and identically distributed inframarginal rents, we thus have each year a probability of 18% that the inframarginal rent of a DSM300 investment equals 0. A DSM300 investment has a lifetime of 3 years under the base scenario. The probability of observing a zero inframarginal rent equal to zero in each of those 3 years equals $(18\%)^3 < 1\%$.

non-normality of the distributions. Skewness is positive for all technologies. The kurtosis is above 3 for all technologies, and hence the distribution has fatter tails than would be expected under a normal distribution.

Table 1 Summary statistics of inframarginal rents (in €/kW/y) under the base scenario

	mean	sd	P(IR=0)	P(IR>100)	min	median	max	skew	kurt
New CCGT	67.87	82.03	0.00	0.13	23.52	44.63	925.49	6.99	66.12
New OCGT	27.69	75.34	0.02	0.06	0.00	5.98	822.65	7.27	68.99
Existing OCGT	23.44	62.31	0.04	0.05	0.00	4.46	658.68	7.13	65.79
Refurbished OCGT	23.44	62.31	0.04	0.05	0.00	4.46	658.68	7.13	65.79
Existing CCGT	50.11	77.89	0.00	0.12	9.91	27.57	912.11	7.59	78.71
Refurbished CCGT	50.11	77.89	0.00	0.12	9.91	27.57	912.11	7.59	78.71
Old CCGT	36.10	76.45	0.00	0.08	1.82	13.35	888.03	7.75	80.90
Refurbished old CCGT	36.10	76.45	0.00	0.08	1.82	13.35	888.03	7.75	80.90
New offshore	180.28	17.00	0.00	1.00	134.18	178.47	289.07	2.80	17.88
New onshore	124.96	12.26	0.00	0.99	96.13	122.70	207.57	3.16	19.81
New PV	45.87	4.26	0.00	0.00	37.28	45.47	83.61	4.23	35.08
DSM 300	21.24	69.81	0.17	0.04	0.00	2.69	782.87	7.99	79.06
DSM 500	18.07	63.76	0.38	0.02	0.00	1.50	721.51	8.26	82.82
DSM 1000	13.88	50.68	0.48	0.02	0.00	1.00	574.84	8.36	84.02
DSM 2000	6.77	25.27	0.52	0.02	0.00	0.00	287.00	8.40	84.68
PSP	14.32	14.87	0.00	0.00	2.15	7.96	95.26	2.15	8.71
Batteries 2h	13.56	11.05	0.00	0.00	3.78	9.50	65.83	1.98	7.34
Batteries 4h	23.92	17.06	0.00	0.01	8.53	17.33	114.70	2.12	8.44

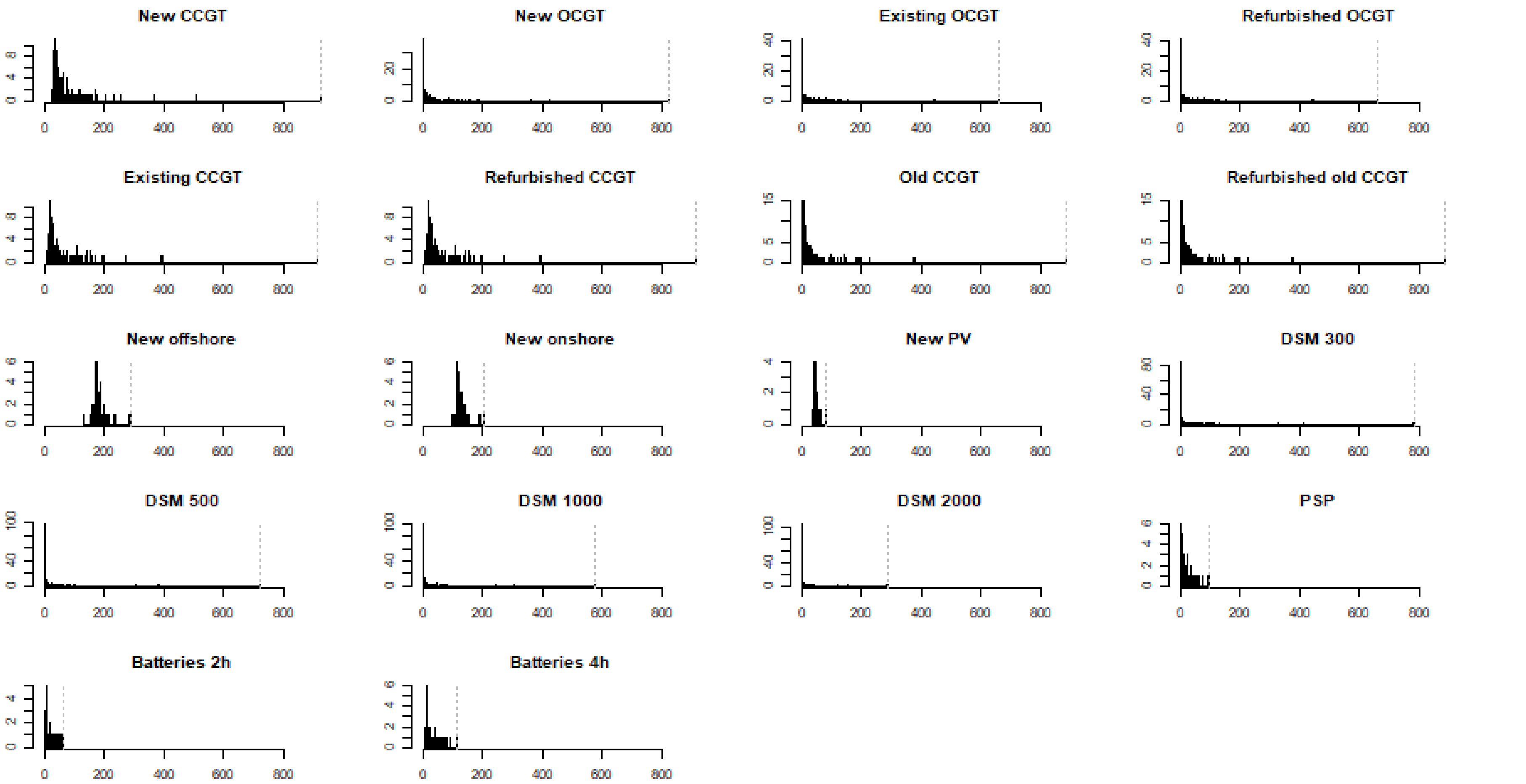

Figure 1 Histogram of yearly inframarginal rents under the base scenario. The grey dashed line indicates the maximum value of the series.

4.2. Project return distribution and hurdle premium calibration under the base scenario

We now simulate N=10'000 possible investment paths by resampling from the yearly inframarginal rents distribution under the base scenario. For each path, we compute the internal rate of return. This leads to N simulated returns: R_1 , R_2 , ..., R_N for which we compute the mean and standard deviation as follow: $\mu = \frac{1}{N}\sum_{i=1}^{N} R_i$ and $\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(R_i - \mu)^2}$. The semideviation measures the "bad" volatility in terms of the variability in the lower than expected returns: $= \sqrt{\frac{1}{N}\sum_{i=1}^{N}(\min\{R_i - \mu, 0\})^2}$. The value-at-risk and expected shortfall at loss probability α correspond to the α-quantile of the return distribution and the mean return below that quantile: $VaR = R_{(\lceil \alpha N \rceil)}$ and $ES = \frac{1}{\lceil \alpha N \rceil}\sum_{i=1}^{\lceil \alpha N \rceil} R_{(i)}$ where $R_{(1)}, R_{(2)}, \ldots, R_{(N)}$ are the ordered simulated return observations such that $R_{(i)} \leq R_{(i+1)}$. Popular choices for α are 1%, 2.5% and 5%. We further also report the standardized skewness and kurtosis. It can be expected that the investor anchors his decision versus two reference values: 0 and the reference WACC. We therefore also report the probability that the return is below those reference values: $P(R < 0) = \frac{1}{N}\sum_{i=1}^{N} I[R_i < 0]$ and $P(R < WACC^*) = \frac{1}{N}\sum_{i=1}^{N} I[R_i < WACC^*]$ where $I[.]$ is the indicator function that is one if the condition is fulfilled, and zero otherwise. $P(R < 0)$ is the probability of losing money in the investment.

These performance statistics are reported in the table below. The column with the mean simulated return is crucial: this is the expected return estimate which is a key quantity in the investment decision, as the project is considered economically viable when the expected return exceeds the hurdle rate. Only running an existing CCGT qualifies for economic viability under the assumptions of the base scenario. Specifically, we find that the use of an existing CCGT that does not require refurbishment is highly profitable in terms of expected returns (mean return is 30%). This can be attributed to the harvesting of inframarginal rents under price spikes which are multiples of the cost required to operate an existing CCGT[20].

When refurbishment is needed, the expected return drops from 30% to 4%. In case of a greenfield investment in new CCGT the expected return is 2%, while for OCGT it is negative (-4%). The expected returns for Wind, PV, DSM300 and DSM2000 are negative under the base scenario.

Positive expected returns are also observed for old CCGT (6%), refurbished CCGT (4%), and new CCGT (2%). A positive return does not mean financial viability as the investments imply an opportunity cost for the investor and require a compensation for the investment risk. Indeed, investment in these technologies is only viable when the expected return exceeds the hurdle rate, which, in our calibration is at least 7.63%.

Except for existing CCGT, all technologies have an expected return below the minimum hurdle rate of 7.63% and are thus not viable under the base scenario. This is expected given the scenario used, namely a scenario at the tipping point of overall economic viability for new capacity as referred to in Elia's (2021) Adequacy & Flexibility study which is characterized by not yet being adequate and hence exhibiting several price spikes). It follows also from the fact that profitability is only assessed from the perspective of inframarginal rents in the energy market (i.e. excluding any more stable revenues streams that may come from other markets, such as a capacity remuneration mechanism).

[20] This result is highly affected by the use of a non-adequate scenario, resulting in more price spikes. Section 6.3 provides the result in case of an adequate scenario.

Consider now the risk profile of running an existing CCGT. Whether it qualifies for economic viability depends also on the hurdle premium required. There is clearly an investment risk. Running an existing CCGT leads to returns that can be negative: in the 5% worst scenarios the average return is -23%.

Besides the downside risk, there is also the upside of extreme positive returns. On average, across all scenarios, the average return is 30% which exceeds the median return of 10% due to the positive skewness. The horizon of the project is 3 years. The shorter horizon contributes to the higher observed variability as there is less scope for time diversification.

How does the hurdle premium compare across technologies. Below we use the distribution results under the base scenario to obtain a first ranking of the different technologies under the base scenario. The ranking is based on various risk dimensions: probability of zero inframarginal rents, the lifetime of the investment, the position in the merit order book, the return variability (quantifying the extent that the return may differ from the expected return), the return semideviation (variability of returns below the expected return) and the risk of extreme negative returns leading to capital loss. In the next section, this ranking is then adjusted by taking into account the impact of considering alternative scenarios.

1 - Least risky projects: Wind (off-shore and onshore), PV

The investments in renewable energy considered (wind , both off-shore and onshore, and PV) all have very low return variability (standard deviation <1%) and low levels of potential capital loss. For new PV, the range of returns is -5% to -2%, while for new offshore, the range of returns is -4% to -2%. The low variability is explained by their long horizon of at least 15 years and that they are ranked first in dispatch of technologies under the merit order principle. These two factors explain the lower variability for wind and solar power. Under the base scenario, they are ranked first in terms of lowest risk profile.

2 - Low financial risk profile under the base scenario: PSP, large scale batteries, and new CCGT

New CCGT is ranked at the beginning in the merit order. The storage solutions are not affected by the merit order. All have low return variability under the base scenario (standard deviation between 1% and 3%).

3 - Medium financial risk profile under the base scenario: refurbished CCGT

A refurbished CCGT has medium return variability (standard deviation between 5% and 10%) but mostly good variability offering upside potential and relatively lower probability of negative returns. It can be seen as more risky than a new CCGT because of its later position in the merit order book, but less risky than the OCGT technology.

4 - Medium-high financial risk profile under the base scenario: new OCGT, refurbished old CCGT

A new OCGT has low return variability (standard deviation between 3.5% and 5%) while a refurbished old CCGT has a higher variability (standard deviation of 7-8%). However their semideviation is similar, and a refurbished old CCGT has substantial good variability offering upside potential.

5 - High financial risk profile under the base scenario: refurbished OCGT

A refurbished OCGT has the same semideviation as a refurbished old CCGT but its upside potential is less as can be seen from the maximum return (39% for refurbished OCGT versus 86% for refurbished old CCGT). It has also markedly more negative returns and worse downside risk performance in terms of VaR and ES. This is consistent with the order in the merit book.

6 – <u>Most risky projects under the base scenario: existing CCGT, old CCGT and DSM</u>

Existing CCGT, old CCGT and DSM all have high variability due to the shorter horizon of the project (and hence less opportunities for time diversification) and the absence of CAPEX investments required. Because of the absence of CAPEX, the variability in the rents leads to a high variability in the returns.

As a robustness check, we report in Table 5 the break-even values for a CRRA investor to be indifferent between the projects solely based on their variability. As explained in Boudt (2021) this requires to first neutralize the heterogeneity in expected return such that we only measure the impact of the variability. The break-even values indicate, after adjustment for equal expected returns, the return compensation required to be indifferent for the investment risk involved, taking new PV as the reference. The ranking based on the break-even values is consistent with the discussion above.

Conclusion. Analysis of the base scenario shows clear heterogeneity in the return distribution of the projects considered. The variability is determined by the cost, lifetime, efficiency and consequent position in the merit order book of the technology. The downside risk analysis lets us compute key risk characteristics such as the return variance, the magnitude of the returns that are less than expected, the probability of negative returns and the value-at-risk and expected shortfall describing the 5% worst outcomes.

Based on the arguments above, we have the following ranking for compensation for (downside) risk under the base scenario. Note that this is an ordinal representation and that we do not adjust here for the possibility of hedging or the policy/model risk implications.

Minimum exposure to lower than expected returns under the base scenario					Maximum exposure to lower than expected returns the base scenario
Offshore Onshore PV	New CCGT Batteries PSP	Refurbished CCGT	New OCGT Refurbished old CCGT	Refurbished OCGT	Existing CCGT Old CCGT Existing OCGT DSM 300, 500, 1000, 2000

Table 5 Compensation required by a CRRA investor (γ=4) to be compensated for the difference in magnitude of deviation of returns from expected return between the least volatile investment (new PV) and the alternative investments. The impact of the level of expected return is neutralized by setting the mean return of all investments to the mean return of new PV in this break-even analysis.

	CRRA (gamma=4)
1 – Same very low risk profile as new PV under the base scenario: Wind (off-shore and onshore)	
New offshore	0.00
New onshore	0.00
2 – Small additional compensation required because of higher return variability than new PV under the base scenario: PSP, batteries, and new CCGT	
PSP	0.01
Batteries 2h	0.02
Batteries 4h	0.02
New CCGT	0.02
3 - Medium additional compensation required because of higher return variability than new PV under the base scenario: refurbished CCGT	
Refurbished CCGT	0.06
4 - Medium-high additional compensation required because of higher return variability than new PV under the base scenario: new OCGT, refurbished old CCGT	
New OCGT	0.09
Refurbished old CCGT	0.10
5- High additional compensation required because of higher return variability than new PV under the base scenario: refurbished OCGT	
Refurbished OCGT	0.25
DSM 2000	0.27
6 – Highest additional compensation required because of higher return variability than new PV under the base scenario: existing CCGT, old CCGT and DSM	
DSM 1000	0.39
DSM 500	0.46
DSM 300	0.50
Old CCGT	0.68
Existing CCGT	0.59
Existing OCGT	0.93

Table 2 Summary statistics of project returns under the base scenario (Reference WACC is 4.89%. Hurdle rates are between 7.63% and 13.16%.)

	mean	sd	P(R<0)	P(R<WACC*)	median	min	max	skew	kurt	semidev	5% VaR	5% ES
New CCGT	0.02	0.03	0.30	0.89	0.01	-0.04	0.33	2.12	11.70	0.02	-0.02	-0.02
New OCGT	-0.04	0.05	0.83	0.96	-0.05	-0.20	0.41	1.08	6.71	0.03	-0.12	-0.14
Existing OCGT	-0.01	1.05	0.64	0.66	-0.22	-1.00	10.14	6.13	53.42	0.39	-0.77	-0.83
Refurbished OCGT	-0.10	0.07	0.90	0.97	-0.10	-0.42	0.39	0.59	4.62	0.04	-0.20	-0.22
Existing CCGT	0.30	0.82	0.35	0.42	0.10	-0.37	9.27	7.50	77.22	0.27	-0.20	-0.23
Refurbished CCGT	0.04	0.08	0.28	0.74	0.02	-0.09	0.93	4.99	41.67	0.03	-0.03	-0.04
Old CCGT	0.06	0.83	0.62	0.66	-0.14	-0.69	9.01	7.13	72.01	0.29	-0.48	-0.52
Refurbished old CCGT	-0.01	0.08	0.69	0.88	-0.03	-0.18	0.86	3.92	29.93	0.04	-0.10	-0.11
New offshore	-0.03	0.00	1.00	1.00	-0.03	-0.04	-0.02	0.68	3.92	0.00	-0.04	-0.04
New onshore	0.01	0.00	0.01	1.00	0.00	0.00	0.03	0.78	4.07	0.00	0.00	0.00
New PV	-0.04	0.00	1.00	1.00	-0.04	-0.05	-0.02	1.09	5.29	0.00	-0.05	-0.05
DSM 300	-0.46	0.53	0.93	0.94	-0.57	-1.00	4.40	4.72	37.43	0.23	-0.93	-0.96
DSM 500	-0.52	0.50	0.95	0.95	-0.61	-1.00	3.98	4.42	33.99	0.22	-1.00	-1.00
DSM 1000	-0.59	0.43	0.95	0.96	-0.66	-1.00	3.03	3.74	26.44	0.20	-1.00	-1.00
DSM 2000	-0.72	0.28	0.97	0.98	-0.76	-1.00	1.20	2.19	11.33	0.15	-1.00	-1.00
PSP	-0.10	0.01	1.00	1.00	-0.10	-0.15	-0.06	-0.13	2.88	0.01	-0.12	-0.12
Batteries 2h	-0.12	0.02	1.00	1.00	-0.12	-0.19	-0.06	0.02	2.74	0.01	-0.15	-0.16
Batteries 4h	-0.11	0.02	1.00	1.00	-0.11	-0.17	-0.05	0.13	2.77	0.01	-0.14	-0.14

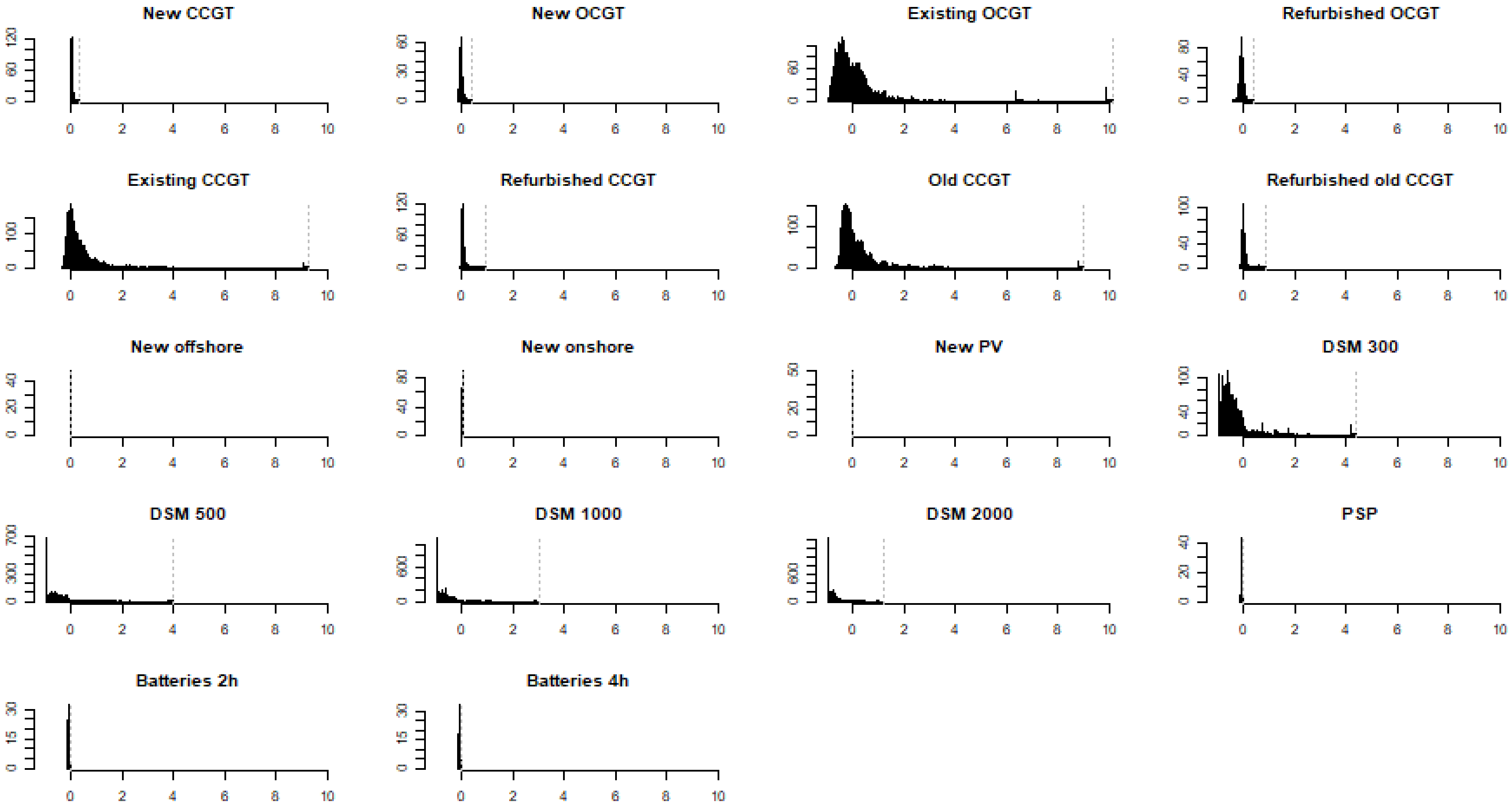

Figure 2 Histogram of internal rate of returns under the base scenario. The grey dashed line indicates the maximum value of the series.

4.3. Impact on project return distribution of alternative scenarios

The simulation results obtained under the base scenario are heavily dependent on the assumptions that define the scenario. Given the projected distributions, a real-world investor will also consider alternative scenarios. We integrate this in our decision making model by means of the hurdle premium calibration based on a combination of quantitative and qualitative conclusions.

We use here the same quantitative setup as in the previous subsection but modify assumptions leading to different return distribution. The change in expected return inform about the magnitude of the impact of making alternative assumptions.

The expected return of the investor is likely to be a weighted average return of the various adverse scenarios. The more importance the investors attach to adverse scenarios as compared to the base scenario, the lower the perceived return. Since the expected return calculation used in the viability assessment is limited to the boundaries of using a single scenario, we need to account for these adverse effects through the hurdle premium calibration. The more negative the effect is of a plausible adverse scenario, the higher the hurdle rate is (*ceteris paribus*).

The impact increases when the likelihood of the adverse scenario is higher. Compared to the analysis in Boudt (2021) for the period 2022-2032, the likelihood of a number of adverse scenarios has increased. Indeed, given the current political discussions, both at the European[21] and the national[22] level, regarding a price limit and the taxation of excess profits, the first two scenarios ("what if … price cap?" and "what if…taxed away") have in the current environment a higher weight than in the previous analysis of Boudt (2021). These alternative scenarios have a large downward impact on the expected return for the existing, old and refurbished OCGT and CCGT, and the DSM technologies. Finally, a scenario of high prices and a subsequent change in the merit order leads to a less frequent activation of gas-fired installation. The plausibility of such a scenario has also significantly increased over the past years.

4.3.1. What if high price spikes are heavily discounted or subject to a perceived price cap?

As in Elia (2021), we use simulated rents obtained under a model in which there is a maximum energy price at which the modelled market can clear. In the base scenario, there is a price cap at 3000 €/MWh. We now study the effect on the project return of an implicit or explicit price cap at 300, 1000 and 2000 €/MWh.

Under the base scenario, higher prices than 300, 500, 1000 and 2000 €/MWh are likely to coincide with periods in which part of the capacity of wind and PV are not available.

Analyzing the impact of lowering the price cap from 3000 €/MWh to 300, 500, 1000 and 2000 €/MWh is therefore especially relevant for the CCGT, OCGT and DSM technologies.

For the DSM technologies, the impact can be easily predicted. A DSM2000 is only activated if prices are above 2000 €/MWh. Investors who expect a price limit to be at 2000 €/MWh will never invest in a DSM2000 since their investment return is -100% (zero revenues). For DSM300, the revenues will be reduced when lowering the price cap to 500, 1000 and 2000 €/MWh. At a price cap of 300 €/MWh, there are no revenues and hence the investment return is -100% with certainty.

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[21] https://ec.europa.eu/commission/presscorner/detail/nl/ip_22_5489
[22] https://www.vrt.be/vrtnws/nl/2022/10/11/begroting-inhoud/

In the tables below we show the sensitivity of the expected project return and the probability of negative returns to the level of the price cap. We see that imposing the price cap reduces the expected return and increases the risk of negative returns for all technologies.

The biggest expected return impact is for the DSM technologies and for the existing and old CCGT and OCGT projects. The impact of lowering the price cap from 3000 €/MWh to 2000 €/MWh is a reduction in expected return of over 10 percentage points. For an existing OCGT, the loss in expected return is even 16 percentage points.

Imposing a price cap limits the upside variability in the returns leading to the lower expected returns. As can be seen in the table with the 5% expected shortfall, it has little impact on the lower tail of the return distribution.

Based on the expected return impact document in the table, we have the following ordinal ranking for compensation for a lower maximum price under the base scenario.

Minimum downside impact on expected return					Maximum downside impact on expected return
Wind, PV, PSP, Batteries	New CCGT	New OCGT Refurbished OCGT Refurbished CCGT	DSM500 Existing CCGT Old CCGT	DSM 1000	DSM 2000 Existing OCGT

Table 3 Impact of price limits on expected return of the different projects

	Base: max 3000	max 2000	max 1000	max 500	max 300
New CCGT	0.02	0.01	-0.01	-0.01	-0.02
New OCGT	-0.04	-0.07	-0.10	-0.12	-0.14
Existing OCGT	-0.01	-0.17	-0.35	-0.46	-0.56
Refurbished OCGT	-0.10	-0.12	-0.16	-0.19	-0.22
Existing CCGT	0.30	0.20	0.09	0.03	-0.02
Refurbished CCGT	0.04	0.01	-0.01	-0.02	-0.03
Old CCGT	0.06	-0.05	-0.16	-0.23	-0.28
Refurbished old CCGT	-0.01	-0.04	-0.06	-0.08	-0.10
New offshore	-0.03	-0.04	-0.04	-0.04	-0.04
New onshore	0.01	0.00	-0.01	-0.01	-0.01
New PV	-0.04	-0.06	-0.06	-0.07	-0.07
DSM 300	-0.46	-0.55	-0.66	-0.76	-1.00
DSM 500	-0.52	-0.62	-0.75	-1.00	-1.00
DSM 1000	-0.59	-0.70	-1.00	-1.00	-1.00

DSM 2000	-0.72	-1.00	-1.00	-1.00	-1.00
PSP	-0.10	-0.12	-0.13	-0.14	-0.15
Batteries 2h	-0.12	-0.15	-0.17	-0.19	-0.20
Batteries 4h	-0.11	-0.13	-0.14	-0.15	-0.16

Table 4 Impact of price limits on P(R<0) of the different projects

	Base: max 3000	max 2000	max 1000	max 500	max 300
New CCGT	0.30	0.45	0.70	0.90	0.98
New OCGT	0.83	0.94	1.00	1.00	1.00
Existing OCGT	0.64	0.71	0.83	0.93	0.99
Refurbished OCGT	0.90	0.99	1.00	1.00	1.00
Existing CCGT	0.35	0.39	0.47	0.54	0.62
Refurbished CCGT	0.28	0.42	0.67	0.84	0.96
Old CCGT	0.62	0.68	0.78	0.85	0.91
Refurbished old CCGT	0.69	0.83	0.94	1.00	1.00
New offshore	1.00	1.00	1.00	1.00	1.00
New onshore	0.01	0.54	0.92	0.97	0.99
New PV	1.00	1.00	1.00	1.00	1.00
DSM 300	0.93	0.95	0.98	1.00	1.00
DSM 500	0.95	0.96	0.99	1.00	1.00
DSM 1000	0.95	0.97	1.00	1.00	1.00
DSM 2000	0.97	1.00	1.00	1.00	1.00
PSP	1.00	1.00	1.00	1.00	1.00
Batteries 2h	1.00	1.00	1.00	1.00	1.00
Batteries 4h	1.00	1.00	1.00	1.00	1.00

Table 5 Impact of price limits on 5% ES of the different projects

	Base: max 3000	max 2000	max 1000	max 500	max 300
New CCGT	-0.02	-0.02	-0.03	-0.03	-0.03
New OCGT	-0.14	-0.15	-0.16	-0.18	-0.20
Existing OCGT	-0.83	-0.85	-0.86	-0.88	-0.92
Refurbished OCGT	-0.22	-0.24	-0.26	-0.28	-0.31
Existing CCGT	-0.23	-0.24	-0.26	-0.26	-0.27
Refurbished CCGT	-0.04	-0.05	-0.06	-0.06	-0.06
Old CCGT	-0.52	-0.52	-0.55	-0.56	-0.58
Refurbished old CCGT	-0.11	-0.12	-0.13	-0.14	-0.15

New offshore	-0.04	-0.05	-0.05	-0.06	-0.06
New onshore	0.00	-0.01	-0.02	-0.03	-0.03
New PV	-0.05	-0.07	-0.09	-0.10	-0.11
DSM 300	-0.96	-0.96	-0.97	-0.98	-1.00
DSM 500	-1.00	-1.00	-1.00	-1.00	-1.00
DSM 1000	-1.00	-1.00	-1.00	-1.00	-1.00
DSM 2000	-1.00	-1.00	-1.00	-1.00	-1.00
PSP	-0.12	-0.14	-0.15	-0.16	-0.17
Batteries 2h	-0.16	-0.18	-0.20	-0.22	-0.24
Batteries 4h	-0.14	-0.16	-0.17	-0.18	-0.19

4.3.2. What if returns above a threshold would be taxed away?

The expected return of several investments is highly influenced by the occurrence of price spikes leading to extreme positive returns. Investors may fear that these extreme positive returns are considered as excess profit by policy makers and taxed away. Such an ex post tax on extreme positive returns has a heterogeneous effect on the expected return for the various technologies. Since it only affects the most extreme positive returns, there is no impact on the lower tail of the distribution.

We document the impact on expected return in the table below where we show the sensitivity to imposing a tax that limits, per investment, the return to at most 50%, 25%, 20% and 15%, as compared to no limit in the base scenario.

A condition to be affected is of course to have extreme positive returns. This is the case for existing OCGT, old OCGT and existing CCGT. These are low CAPEX investments that are activated in case of scarcity. The relatively high inframarginal rents compared to the low costs yield the high return outcomes. Taxing them reduces substantially their expected return. By design the impact is higher when the ceiling is lower.

A similar (but to a lesser extent) is observed for the DSM with low and medium activation cost.

Minimum downside impact on expected return			Maximum downside impact on expected return
Wind, PV, PSP, Batteries, new CCGT, new OCGT, refurbished OCGT, DSM2000 refurbished old CCGT, coal CCS, PSP, batteries	DSM medium activation cost (DSM 1000)	DSM low activation cost (DSM 300 and 500)	existing OCGT, existing CCGT, old CCGT

Table 6 Impact of tax-based return ceiling limits on expected return of the different projects

	Base	max 50%	max 25%	max 20%	max 15%
New CCGT	0.02	0.02	0.02	0.02	0.02
New OCGT	-0.04	-0.04	-0.04	-0.04	-0.04
Existing OCGT	-0.01	-0.16	-0.20	-0.22	-0.23
Refurbished OCGT	-0.10	-0.10	-0.10	-0.10	-0.10
Existing CCGT	0.30	0.15	0.08	0.06	0.04
Refurbished CCGT	0.04	0.03	0.03	0.03	0.03
Old CCGT	0.06	-0.05	-0.10	-0.11	-0.12
Refurbished old CCGT	-0.01	-0.01	-0.02	-0.02	-0.02
New offshore	-0.03	-0.03	-0.03	-0.03	-0.03
New onshore	0.01	0.01	0.01	0.01	0.01
New PV	-0.04	-0.04	-0.04	-0.04	-0.04
DSM 300	-0.46	-0.50	-0.51	-0.51	-0.51
DSM 500	-0.52	-0.55	-0.56	-0.56	-0.57
DSM 1000	-0.59	-0.61	-0.62	-0.62	-0.62
DSM 2000	-0.72	-0.72	-0.72	-0.72	-0.72
PSP	-0.10	-0.10	-0.10	-0.10	-0.10
Batteries 2h	-0.12	-0.12	-0.12	-0.12	-0.12
Batteries 4h	-0.11	-0.11	-0.11	-0.11	-0.11

4.3.3. What if high gas prices lead to a change in the merit order from gas before coal to coal before gas?

We consider a change in merit order by assuming higher gas prices leading to a coal before gas merit order instead of a gas before coal.[23] The assumption on the gas price affects the clearing price in the energy market and therefore affects the inframarginal rents of most technologies. It can be expected that this change in merit order increases expected returns for all investments except the ones which have less margin under this scenario, typically the OCGT.

Figure 2 show the change in inframarginal rents when adapting the scenario. A scatter plot is used with on the x-axis the inframarginal rents in case of the base scenario, and on the y-axis the rents in case of the scenario with high gas prices. The reference point is the 45 degrees line where rents have

[23] In Boudt (2021) we studied a different change in merit order namely by assuming a lower carbon price. This reduces the marginal cost of OCGT and CCGT. The other marginal costs remain the same. When change in merit order is due to lower carbon prices, the effect in general is lower expected returns for all investments (except DSM capacities) than under the base scenario. Indeed, if coal's marginal cost becomes cheaper, gas-fired installations such as CCGTs will be less often activated.

not changes. We see winning technologies (green color) and losing technologies (red color) in cases of this scenario:

- Winners: Renewable Energy Supply (wind, PV), batteries and PSP: their inframarginal rents have clearly increased
- Losers: OCGT
- Mixed: DSM, CCGT

The mixed results for CCGT is due to two factors that have opposite effects on the inframarginal rents. In case of high gas prices, CCGTs tend to lose in running hours, but they win in terms of the « margin » they get as OCGTs are behind them in the merit order, and due to their lower efficiency a lot more expensive. In the scenario of high gas prices, for OCGT, the number of running hours is stable, but their margins are a lot smaller, explaining the lower inframarginal rents.

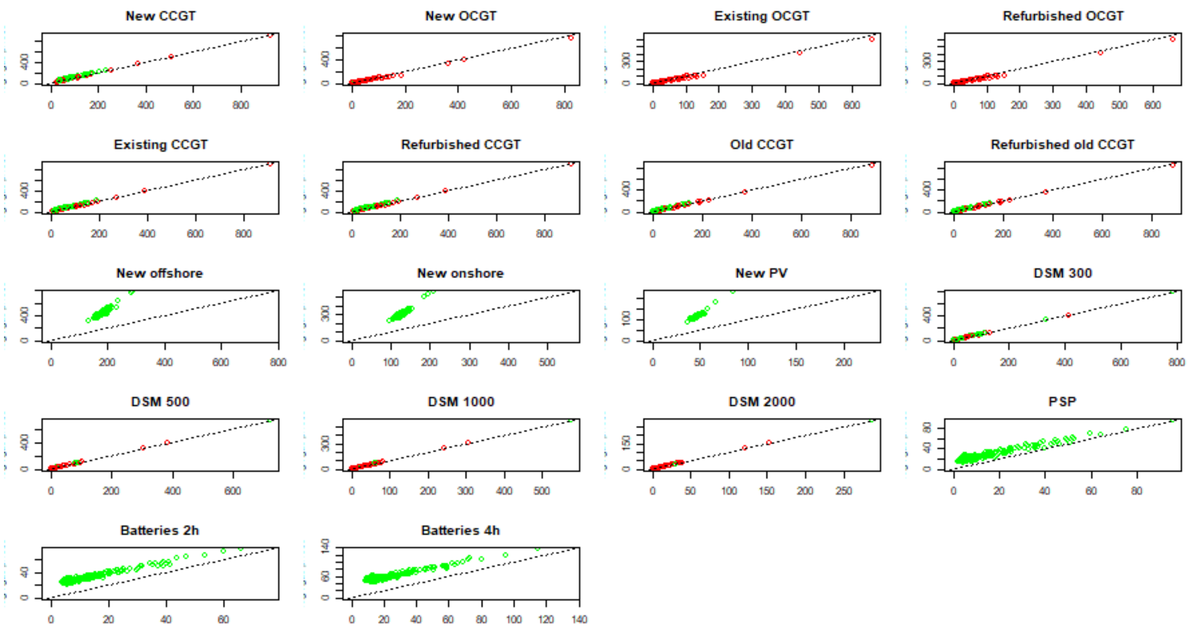

Figure 3 Scatter plot of inframarginal rents in case of high gas prices (y-axis: coal before gasl) versus the base scenario (x-axis: gas before coal). Rents above the 45 degrees line are higher in case of a scenario change.

As DSM capacities are only activated at the end of the merit order (due to the high activation price), changing only the marginal costs for technologies in the beginning of the merit order do not affect the inframarginal rents for DSM. The above intuition is confirmed by the simulation results. There is no impact for the expected returns of DSM investment projects.

The merit order change has an impact on new, existing and refurbished 0CGT for which the expected return drops from -4%, -1% and -10% to -6%, -13% and -9%, respectively. Especially for existing OCGT the impact is thus material. It follows that, when investors consider that there is a probability that the marginal cost of coal is reduced in the future compared to the level assumed in the base scenario, they will then expect lower expected return which means that the hurdle rate used in the base scenario needs to be increased for the new, refurbished and existing OCGT.

Based on the arguments above, we have the following ordinal ranking for the increase in hurdle premium needed when investors expect a negative return impact due to a reduction of the marginal cost of coal as compared to the base scenario:

Minimum downside impact on expected return				Maximum downside impact on expected return
Winners or no impact: Wind PV Existing CCGT Refurbished CCGT DSM	New OCGT	Refurbished OCGT		Existing OCGT

Table 7 Impact of Merit Order Change (MOC; shock is high gas prices) on expected return, probability of negative returns and 5% expected shortfall of the different projects

	base E[R]	MOC	base P(R<0)	MOC	base 5% ES	MOC
New CCGT	0.02	0.03	0.30	0.08	-0.02	-0.01
New OCGT	-0.04	-0.06	0.83	0.87	-0.14	-0.15
Existing OCGT	-0.01	-0.19	0.64	0.72	-0.83	-0.96
Refurbished OCGT	-0.10	-0.13	0.90	0.94	-0.22	-0.28
Existing CCGT	0.30	0.36	0.35	0.23	-0.23	-0.21
Refurbished CCGT	0.04	0.05	0.28	0.15	-0.04	-0.03
Old CCGT	0.06	0.08	0.62	0.60	-0.52	-0.49
Refurbished old CCGT	-0.01	-0.01	0.69	0.68	-0.11	-0.10
New offshore	-0.03	0.09	1.00	0.00	-0.04	0.08
New onshore	0.01	0.14	0.01	0.00	0.00	0.13
New PV	-0.04	0.07	1.00	0.00	-0.05	0.07
DSM 300	-0.46	-0.45	0.93	0.93	-0.96	-0.95
DSM 500	-0.52	-0.53	0.95	0.95	-1.00	-1.00
DSM 1000	-0.59	-0.59	0.95	0.95	-1.00	-1.00
DSM 2000	-0.72	-0.72	0.97	0.97	-1.00	-1.00
PSP	-0.10	-0.06	1.00	1.00	-0.12	-0.07
Batteries 2h	-0.12	-0.03	1.00	1.00	-0.16	-0.05
Batteries 4h	-0.11	-0.01	1.00	0.92	-0.14	-0.03

4.3.3. What if we go from inadequate to adequate?

The base scenario that we consider corresponds to a situation where existing capacity is profitable but adding more investments to the system would result in a loss. The available capacity does not lead to an adequate system. Consider now the case where investors expect that nevertheless there will be additional investment such that we end up in an adequate scenario. Since there is more supply, electricity prices will be lower on average and therefore we expect lower inframarginal rents and expected returns for all technologies.

This is confirmed in the distribution of inframarginal rents and the return simulation results. The scatter

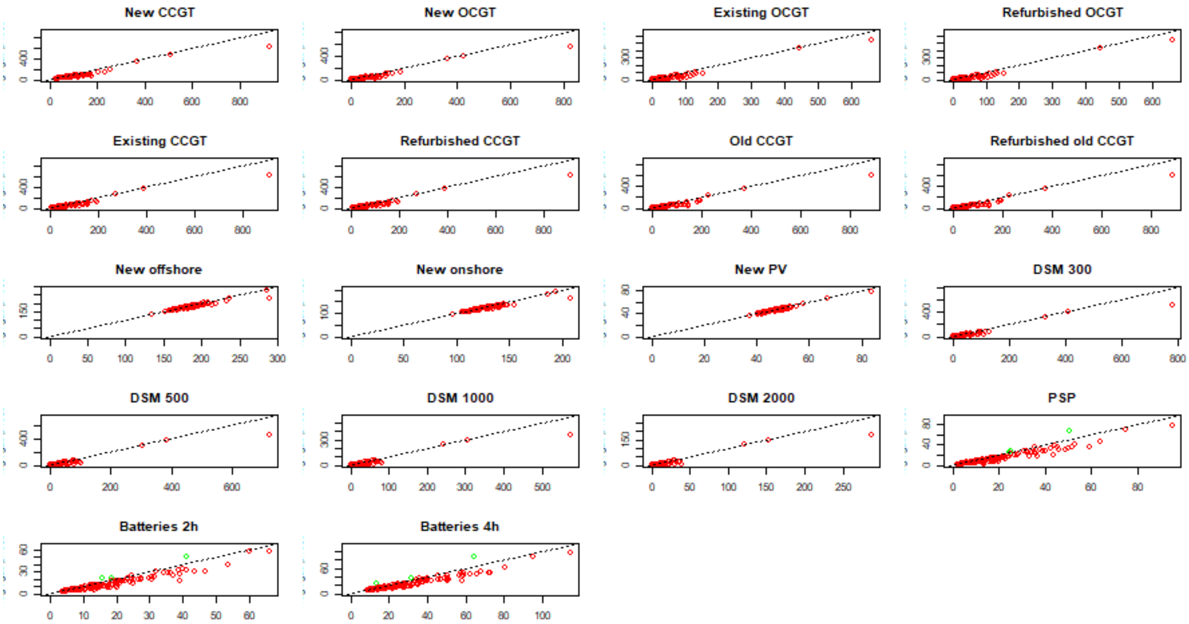

Figure 4 Scatter plot of inframarginal rents in case of adequacy (y-axis) versus the base scenario (x-axis). Rents above the 45 degrees line are higher in case of a scenario change (green) and vice verse in case of a loss (red).

While for baseload, wind, PV, PSP, and large scale batteries the effect is small, we find a large effect on the expected returns of existing OCGT, existing CCGT, old CCGT and DSM: their expected return is at least 10 percentage points lower than in the base scenario.

For new CCGT, OCGT and refurbished CCGT the impact is also substantial: expected returns are around 5 percentage points lower.

Switching from an inadequate to an adequate scenario has thus a large impact on the expected returns of the DSM and OCGT/CCGT investments. Note that the risk is partly endogenous to the investment decisions.

Based on the obtained simulation results, we have the following ranking for compensation due to a perceived risk of switching from an inadequate to an adequate scenario.

Minimum downside impact on expected return	⟷			Maximum downside impact on expected return
Wind, PV, PSP, Batteries		New CCGT New OCGT Refurbished CCGT	DSM 300, 500, 1000	Existing OCGT Existing CCGT Old CCGT

		Refurbished OCGT DSM2000		

Table 8 Impact of change from base scenario to a scenario of adequacy

	base E[R]	Adeq	base P(R<0)	Adeq	base 5% ES	Adeq
New CCGT	0.02	-0.02	0.30	0.78	-0.02	-0.05
New OCGT	-0.04	-0.09	0.83	0.95	-0.14	-0.18
Existing OCGT	-0.01	-0.27	0.64	0.82	-0.83	-0.92
Refurbished OCGT	-0.10	-0.15	0.90	0.97	-0.22	-0.28
Existing CCGT	0.30	0.02	0.35	0.65	-0.23	-0.37
Refurbished CCGT	0.04	-0.02	0.28	0.78	-0.04	-0.09
Old CCGT	0.06	-0.18	0.62	0.83	-0.52	-0.62
Refurbished old CCGT	-0.01	-0.07	0.69	0.87	-0.11	-0.16
New offshore	-0.03	-0.04	1.00	1.00	-0.04	-0.04
New onshore	0.01	0.00	0.01	0.27	0.00	0.00
New PV	-0.04	-0.05	1.00	1.00	-0.05	-0.05
DSM 300	-0.46	-0.59	0.93	0.95	-0.96	-0.99
DSM 500	-0.52	-0.65	0.95	0.96	-1.00	-1.00
DSM 1000	-0.59	-0.69	0.95	0.96	-1.00	-1.00
DSM 2000	-0.72	-0.79	0.97	0.98	-1.00	-1.00
PSP	-0.10	-0.11	1.00	1.00	-0.12	-0.14
Batteries 2h	-0.12	-0.14	1.00	1.00	-0.16	-0.18
Batteries 4h	-0.11	-0.13	1.00	1.00	-0.14	-0.16

4.3.4. What if we go from inadequate to adequate and the merit order changes due to higher gas prices?

The change from inadequate to adequate and the merit order change due to higher gas prices are two adverse effects for the investors in OCGT. The “what if…” analysis done so far is a partial effect analysis studying the effect on the expected return and risk if one of the design parameters is changed (while keeping others constant). In practice, investors may also consider scenarios where several design parameters change at the same time. To illustrate that the joint effect may differ from the largest partial effect, we show below the return distribution when the scenario is adequate (see Subsection 6.3.2) and the carbon price is lower (see Subsection 6.3.3) than in the base scenario.

For the CCGT and OCGT projects, the adequacy scenario has a detrimental effect on expected returns. Especially the existing CCGT and OCGT projects are hit: compared to the base scenario their expected return drops from 30% and -1% to 3% and -41%, respectively. A similar effect is observed for the DSM projects.

The change in merit order benefits to new baseload, extension baseload, coal CCS, wind and PV, and they preserve these gains when the merit order changes.

Based on the obtained simulation results, we have the following ranking for compensation due to considering the joint effect of switching from an inadequate to an adequate scenario and a reduction in the marginal cost of carbon versus only their partial effect.

Minimum downside impact on expected return	⟵⟶			Maximum downside impact on expected return
Winners or no impact: Wind PV Batteries	New OCGT New CCGT Refurbished CCGT	Refurbished OCGT	DSM 1000 DSM2000	Existing OCGT Existing CCGT DSM 300, DSM 500

Table 9 Impact of change from base scenario to a scenario of adequacy with change in merit order from gas before coal to coal before gas

	base	merit change	adequacy	merit+adequacy
New CCGT	0.02	0.03	-0.02	-0.02
New OCGT	-0.04	-0.06	-0.09	-0.10
Existing OCGT	-0.01	-0.19	-0.27	-0.41
Refurbished OCGT	-0.10	-0.13	-0.15	-0.18
Existing CCGT	0.30	0.36	0.02	0.03
Refurbished CCGT	0.04	0.05	-0.02	-0.02
Old CCGT	0.06	0.08	-0.18	-0.19
Refurbished old CCGT	-0.01	-0.01	-0.07	-0.07
New offshore	-0.03	0.09	-0.04	0.08
New onshore	0.01	0.14	0.00	0.14
New PV	-0.04	0.07	-0.05	0.07
DSM 300	-0.46	-0.45	-0.59	-0.59
DSM 500	-0.52	-0.53	-0.65	-0.65
DSM 1000	-0.59	-0.59	-0.69	-0.69
DSM 2000	-0.72	-0.72	-0.79	-0.79
PSP	-0.10	-0.06	-0.11	-0.07
Batteries 2h	-0.12	-0.03	-0.14	-0.05
Batteries 4h	-0.11	-0.01	-0.13	-0.03

4.3.5. What if a technology becomes obsolete and revenues go to zero 15, 10, 5 years after investment?

The merit order is a key determinant for the revenues that an investment in electricity capacity will earn. For long-term investments, there is the risk that research and development will lead to more efficient technologies or that policy changes would favor new types of capacities, making the current technologies obsolete.

We replicate this in our simulation setting by keeping the initial investment horizon at 20 years for new CCGT and OCGT, and 15 years for the CCGT with refurbishments, wind and PV. However, at the time the technology becomes obsolete we set all subsequent inframarginal rents to zero. The remaining FOM reserve included in the initial investment is modeled as a cash inflow at the time when the technology becomes obsolete.

A reduced economic lifetime of the investment impacts expected return and risk. The risk increases as there is less benefit from time diversification. The expected return typically decreases since the initial CAPEX investment has a higher relative weight if there are less years with revenues. One exception is the case of a technology with negative profitability for which the cash inflow of not having to pay the FOM for the remaining years can have a positive impact on the return. In our simulation, this exceptional case is only observed for refurbished OCGT.

The impact is the largest for the investment with high CAPEX and long lifetime. When after 15, 10 or 5 years, it turns out that the new CCGT is obsolete, then the expected return is no longer 2% but 0%, -3% and -11%. For new CCGT the probability of negative returns increases from 30% to 62% when the duration is limited to 15 years. A negative but smaller impact is also observed for new OCGT, for which the expected return drops from -4% to -5%, -7% and -14% when becoming obsolete after 15, 10 and 5 years, respectively.

For Wind and PV the lifetime is 15 years. If it becomes 10 or 5 years, then the expected return for new PV is -7% and -16% instead of -4%.

For refurbished CCGT, the lifetime is also 15 years. If it becomes 10 or 5 years, then the expected return is 10.5% and 6.1% instead of 12.5%.

Based on the obtained simulation results, we have the following ordinal ranking for compensation due to a perceived risk of the technology becoming obsolete.

Minimum downside impact on expected return	⟵⟶		Maximum downside impact on expected return
No impact as duration is less than 5 years: Old CCGT, Existing CCGT, DSM	Refurbished OCGT Refurbished CCGT	New OCGT New offshore, New onshore, PV PSP Batteries	New CCGT

Table 10 Expected project returns when technology becomes obsolete

	Base	max 15 yrs	max 10 yrs	max 5 yrs
New CCGT	0.02	0.00	-0.03	-0.11
New OCGT	-0.04	-0.05	-0.07	-0.14
Existing OCGT	-0.01	-0.01	-0.01	-0.01
Refurbished OCGT	-0.10	-0.10	-0.06	-0.07
Existing CCGT	0.30	0.30	0.30	0.30
Refurbished CCGT	0.04	0.04	0.02	-0.01
Old CCGT	0.06	0.06	0.06	0.06
Refurbished old CCGT	-0.01	-0.01	-0.01	-0.04
New offshore	-0.03	-0.03	-0.07	-0.16
New onshore	0.01	0.01	-0.03	-0.11
New PV	-0.04	-0.04	-0.07	-0.16
DSM 300	-0.46	-0.46	-0.46	-0.46
DSM 500	-0.52	-0.52	-0.52	-0.52
DSM 1000	-0.59	-0.59	-0.59	-0.59
DSM 2000	-0.72	-0.72	-0.72	-0.72
PSP	-0.10	-0.09	-0.11	-0.18
Batteries 2h	-0.12	-0.12	-0.13	-0.21
Batteries 4h	-0.11	-0.11	-0.14	-0.26

Table 11 Probability of negative returns when technology becomes obsolete

	Base	max 15 yrs	max 10 yrs	max 5 yrs
New CCGT	0.30	0.62	0.86	0.97
New OCGT	0.83	0.88	0.92	0.97
Existing OCGT	0.64	0.64	0.64	0.64
Refurbished OCGT	0.90	0.90	0.91	0.95
Existing CCGT	0.35	0.35	0.35	0.35
Refurbished CCGT	0.28	0.28	0.44	0.72
Old CCGT	0.62	0.62	0.62	0.62
Refurbished old CCGT	0.69	0.69	0.75	0.86
New offshore	1.00	1.00	1.00	1.00
New onshore	0.01	0.01	1.00	1.00
New PV	1.00	1.00	1.00	1.00
DSM 300	0.93	0.93	0.93	0.93

DSM 500	0.95	0.95	0.95	0.95
DSM 1000	0.95	0.95	0.95	0.95
DSM 2000	0.97	0.97	0.97	0.97
PSP	1.00	1.00	1.00	1.00
Batteries 2h	1.00	1.00	1.00	1.00
Batteries 4h	1.00	1.00	1.00	1.00

Table 12 5% ES when technology becomes obsolete

	Base	max 15 yrs	max 10 yrs	max 5 yrs
New CCGT	-0.02	-0.04	-0.07	-0.15
New OCGT	-0.14	-0.10	-0.12	-0.18
Existing OCGT	-0.83	-0.83	-0.83	-0.83
Refurbished OCGT	-0.22	-0.22	-0.11	-0.11
Existing CCGT	-0.23	-0.23	-0.23	-0.23
Refurbished CCGT	-0.04	-0.04	-0.05	-0.08
Old CCGT	-0.52	-0.52	-0.52	-0.52
Refurbished old CCGT	-0.11	-0.11	-0.09	-0.10
New offshore	-0.04	-0.04	-0.07	-0.17
New onshore	0.00	0.00	-0.03	-0.12
New PV	-0.05	-0.05	-0.08	-0.16
DSM 300	-0.96	-0.96	-0.96	-0.96
DSM 500	-1.00	-1.00	-1.00	-1.00
DSM 1000	-1.00	-1.00	-1.00	-1.00
DSM 2000	-1.00	-1.00	-1.00	-1.00
PSP	-0.12	-0.10	-0.12	-0.19
Batteries 2h	-0.16	-0.16	-0.16	-0.23
Batteries 4h	-0.14	-0.14	-0.17	-0.28

4.3.6. What if fixed operations and maintenance (FOM) costs are higher

Until now, we have focused on the randomness of the inframarginal rents keeping costs pre-determined. This is of course also a strong assumption. As a sensitivity we study the impact on expected returns of increasing the FOM for each technology with 25%.

A large impact is observed for the technologies for which FOM is the only cost (or equivalently for which the CAPEX is zero), namely existing CCGT and DSM. The expected return for existing CCGT drops from 30% to 14%, for DSM 300 we have a reduction from -46% to -52%.

For new/refurbished CCGT, OCGT the return is around 2 percentage points lower.

Based on the obtained simulation results, we have the following ranking for compensation due to a 25% increase in the assumed FOM costs.

<table>
<tr><td>Minimum downside impact on expected return</td><td colspan="3"></td><td>Maximum downside impact on expected return</td></tr>
<tr><td></td><td>PV
New offshore
New onshore
New baseload
PSP
Batteries</td><td>New CCGT
New OCGT
Refurbished OCGT
Refurbished CCGT
Refurbished old CCGT</td><td>DSM300
DSM500
DSM1000
DSM2000</td><td>Existing CCGT
Existing OCGT
Old CCGT</td></tr>
</table>

Table 13 Impact of 25% increase of FOM cost on project expected returns

	base E[R]	>FOM	base P(R<0)	>FOM	base 5% ES	>FOM
New CCGT	0.02	0.00	0.30	0.52	-0.02	-0.03
New OCGT	-0.04	-0.06	0.83	0.87	-0.14	-0.14
Existing OCGT	-0.01	-0.13	0.64	0.69	-0.83	-0.85
Refurbished OCGT	-0.10	-0.12	0.90	0.95	-0.22	-0.24
Existing CCGT	0.30	0.14	0.35	0.52	-0.23	-0.31
Refurbished CCGT	0.04	0.01	0.28	0.54	-0.04	-0.06
Old CCGT	0.06	-0.06	0.62	0.69	-0.52	-0.56
Refurbished old CCGT	-0.01	-0.04	0.69	0.81	-0.11	-0.13
New offshore	-0.03	-0.04	1.00	1.00	-0.04	-0.05
New onshore	0.01	-0.01	0.01	0.98	0.00	-0.01
New PV	-0.04	-0.05	1.00	1.00	-0.05	-0.06
DSM 300	-0.46	-0.52	0.93	0.95	-0.96	-0.97
DSM 500	-0.52	-0.57	0.95	0.95	-1.00	-1.00
DSM 1000	-0.59	-0.64	0.95	0.96	-1.00	-1.00
DSM 2000	-0.72	-0.75	0.97	0.98	-1.00	-1.00
PSP	-0.10	-0.10	1.00	1.00	-0.12	-0.13
Batteries 2h	-0.12	-0.13	1.00	1.00	-0.16	-0.17
Batteries 4h	-0.11	-0.11	1.00	1.00	-0.14	-0.15

4.3.7. What if zero cost hedging is possible

A further interesting variation on the base scenario is to assume the investor uses forward markets to hedge part of the investment risk. This scenario is of course relevant and considered by investors. Hedging by design reduces the variability of the return. Its impact on expected return is ambiguous and case specific (Boudt, 2021). We refer to Boudt (2021) for an analytical derivation explaining the ambiguity. Specifically, there is a negative effect of the 2nd order centered moment (the variance) on the expected return, but a positive impact of the third order centered moment (the non-standardized skewness). This means that the variance reduction leads to a higher expected return, but this increase is reduced in case of lower (positive) third centered moments. Given that price spikes tend to lead to very large positive returns, there is not only a gain associated to hedging (less variability) but also an opportunity cost of not gaining from the price spike. The total effect is case specific.

As a proxy to document the stabilizing impact of hedging, we simulated return under the scenario that the inframarginal rents are composed for 50% of the mean inframarginal rent (certainty) and 50% of a random draw from the distribution. The use of the mean rent for the rent in case of hedging is a proxy. As mentioned in Boudt (2021), mapping the simulated prices to forward prices introduces model risk. Based on Bessembinder and Lemon (2002), CREG (2020) concludes that "*what a forward market does, is aggregating all potential price scenario's into one forward price, given the forward prices of fuel and CO2 prices known at that moment. This forward price can be viewed as the expected spot price (with a risk premium). This expected spot price is equal to the average of all potential scenario's, weighted with their probability to occur. This means that if all scenario's have the same probability, one needs to take a simple average*." The validity of the approach is conditional upon several specificities and assumptions that are not necessarily verified in practice. Empirical analysis of spot and forward prices seems to confirm this (see e.g. Botterud et al., 2009, and Redl et al., 2009).

The below table show the impact of 50% hedging on expected return, probability of negative returns and the 5% expected shortfall. We see that the gain argument of reducing the variance. All investments have similar or higher expected returns. The risk is also substantially lowered. Especially, the existing CCGT is an attractive investment under this hypothetical hedging scheme.

The existing OCGT has a substantially larger expected return in case of the hypothetical hedging (7% instead of the -1%).

We also report a table with all summary statistics. They confirm the large reduction in variance by hedging 50% of the rents. The reduction in variance is mostly coming from a lower exposure to large positive returns.

In conclusion, hedging reduces the variance and can have a positive impact on the expected return of the investments considered. Our analysis is however hypothetical assuming all the financial instruments were available to hedge and obtain with certainty the average inframarginal rent. Consistent with the previous study (Boudt, 2021), we recommend applying a discount in the hurdle premium calibration when hedging is feasible to reduce the observed downside risk under the base scenario.

Table 14 Impact of 50% hedging on project expected returns, probability of negative returns and 5% expected shortfall

	base E[R]	hedge	base P(R<0)	hedge	base 5% ES	hedge
New CCGT	0.02	0.02	0.30	0.03	-0.02	0.00
New OCGT	-0.04	-0.04	0.83	0.91	-0.14	-0.07
Existing OCGT	-0.01	0.07	0.64	0.59	-0.83	-0.22
Refurbished OCGT	-0.10	-0.08	0.90	0.98	-0.22	-0.12
Existing CCGT	0.30	0.30	0.35	0.00	-0.23	0.06
Refurbished CCGT	0.04	0.04	0.28	0.02	-0.04	0.00
Old CCGT	0.06	0.09	0.62	0.54	-0.52	-0.16
Refurbished old CCGT	-0.01	-0.01	0.69	0.73	-0.11	-0.05
New offshore	-0.03	-0.03	1.00	1.00	-0.04	-0.04
New onshore	0.01	0.01	0.01	0.00	0.00	0.00
New PV	-0.04	-0.04	1.00	1.00	-0.05	-0.04
DSM 300	-0.46	-0.36	0.93	0.95	-0.96	-0.50
DSM 500	-0.52	-0.40	0.95	0.96	-1.00	-0.54
DSM 1000	-0.59	-0.47	0.95	0.97	-1.00	-0.58
DSM 2000	-0.72	-0.61	0.97	0.98	-1.00	-0.68
PSP	-0.10	-0.10	1.00	1.00	-0.12	-0.11
Batteries 2h	-0.12	-0.12	1.00	1.00	-0.16	-0.14
Batteries 4h	-0.11	-0.11	1.00	1.00	-0.14	-0.12

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Table 15 Summary statistics of 50% hedged project returns under the base scenario (hypothetical hedging at the average inframarginal rent)

	mean	sd	P(R<0)	P(R<WACC*)	median	min	max	skew	kurt	semidev	5% VaR	5% ES
New CCGT	0.02	0.01	0.03	0.96	0.01	-0.01	0.12	1.65	7.25	0.01	0.00	0.00
New OCGT	-0.04	0.02	0.91	1.00	-0.04	-0.08	0.12	1.15	4.72	0.01	-0.07	-0.07
Existing OCGT	0.07	0.49	0.59	0.64	-0.06	-0.23	4.96	6.27	54.16	0.17	-0.22	-0.22
Refurbished OCGT	-0.08	0.03	0.98	1.00	-0.09	-0.14	0.09	1.21	4.70	0.02	-0.12	-0.12
Existing CCGT	0.30	0.39	0.00	0.01	0.21	0.01	4.57	7.18	71.90	0.13	0.07	0.06
Refurbished CCGT	0.04	0.03	0.02	0.80	0.03	-0.01	0.37	2.81	16.27	0.01	0.00	0.00
Old CCGT	0.09	0.39	0.54	0.63	-0.02	-0.20	4.34	6.90	67.76	0.13	-0.15	-0.16
Refurbished old CCGT	-0.01	0.03	0.73	0.94	-0.02	-0.07	0.31	2.19	11.13	0.02	-0.04	-0.05
New offshore	-0.03	0.00	1.00	1.00	-0.03	-0.04	-0.03	0.72	4.02	0.00	-0.04	-0.04
New onshore	0.01	0.00	0.00	1.00	0.00	0.00	0.02	0.80	4.13	0.00	0.00	0.00
New PV	-0.04	0.00	1.00	1.00	-0.04	-0.05	-0.03	1.14	5.51	0.00	-0.04	-0.04
DSM 300	-0.36	0.24	0.95	0.95	-0.43	-0.50	1.96	4.93	36.59	0.09	-0.50	-0.50
DSM 500	-0.40	0.22	0.96	0.96	-0.47	-0.54	1.74	4.86	34.88	0.08	-0.54	-0.54
DSM 1000	-0.47	0.19	0.97	0.97	-0.53	-0.58	1.26	4.37	28.30	0.07	-0.58	-0.58
DSM 2000	-0.61	0.12	0.98	1.00	-0.65	-0.68	0.35	3.39	16.90	0.05	-0.68	-0.68
PSP	-0.10	0.01	1.00	1.00	-0.10	-0.12	-0.07	0.27	2.92	0.00	-0.11	-0.11
Batteries 2h	-0.12	0.01	1.00	1.00	-0.12	-0.15	-0.08	0.33	2.89	0.01	-0.13	-0.14
Batteries 4h	-0.11	0.01	1.00	1.00	-0.11	-0.13	-0.07	0.39	2.98	0.01	-0.12	-0.12

4.4. Tentative and conditional calibration of the hurdle premium per technology

In this section, for several considered technologies an indicative estimation of a reasonable hurdle premium is provided. The estimations are based on the principles and methodology developed throughout this study and are also linked to the considered modelling setup for the economic viability assessment. They are conditional on the base scenario considered, as that scenario defined the observed variability and downside risk of the investment return and also the model and policy risk of lower than expected project returns due to the deviations from the base scenario that investors at the date of writing this report may consider. A change in market design, such as the implementation of a capacity remuneration mechanism with fixed capacity payments requires a complete re-evaluation of the hurdle premium for each technology (i.e. the implementation of a capacity remuneration mechanism would result in a lower hurdle premium).

As mentioned earlier in section 3.2, no direct mathematical relationship can be established between the different identified risks and uncertainties and the level of the hurdle premium. The hurdle premium is rather to be set heuristically, and supported by the calculations performed in the context of this study (taking into account their underlying assumptions), based on an assessment of the different identified risks.

The resulting hurdle premium is an absolute number expressing the increase in the hurdle rate of the investment project with respect to the reference WACC used. In our setup the hurdle premium of investment projects in electricity capacity in Belgium at the time of writing this document is constrained by:

- The permissible interval between the minimum and maximum hurdle premium for projects with a horizon of more than three years.
- The consistency in terms of relative ordering between the reference WACC investment and the technologies considered, on the one hand, and the internal ordering of the technologies (based on their investment risks), on the other hand.
- The discussed drivers of the hurdle premium: (i) explained variability and risk of losses under the basis scenario, (ii) model and policy risk and (iii) additional considerations such as hedging opportunities, difference in gearing ratio, difference in lifetime and CAPEX between investments, and impact of state-dependent preferences (subsection 4.3).

The feedback from market parties, financial investors and academic peers, as well as the results of the numerical analysis demonstrate that the model and policy risk is more influential to the investment decision compared to the revenue distribution and downside risk.

Below, we use as a rule of thumb that, for all technologies with an investment horizon of three years and more, the minimum compensation for model and policy risk equals the minimum hurdle premium of $\frac{1+5\%}{1+2.2\%} - 1$ = 2.74%. Technologies with a shorter investment horizon can have a lower hurdle premium. We calibrate the hurdle premiums by ordering the technologies such that technologies with a higher investment risk have a higher hurdle premium.

Before presenting the numbers intended for use in the economic viability assessment, we repeat the important caveat that a change of context, modelling setup or other crucial factors may of course lead to another estimation of such hurdle premiums.

4.4.1. Investment in new solar installation, (onshore or offshore) wind: Lowest premium (2.74%)

Risk of lower than expected returns under base scenario: Very low. The simulation analysis under the base scenario has demonstrated that the variability of returns is "very low" for these installations. Therefore, this parameter has limited impact on the hurdle premium. For wind and solar installation, the availability is obviously fully dependent on the weather conditions. It follows from the simulations, that they have less potential to benefit from price spikes.

Risk of lower than expected returns due to model and policy risk: Low. The profitability of an investment in these installations appears to be quite robust to alternatives. Indeed, the impact on expected return is more limited compared to other technologies. The main risk is the one of becoming obsolete. The current policy framework is supportive on the development of renewable energy capacities (e.g. Green Deal), but this can evolve during the economic lifetime of more than 15 years. Moreover, due to recent developments, model risk has increased for these capacities given that new policy measure target the taxation of excess revenues.

4.4.2. Investment in PSP, and large scale batteries: Hurdle premium of 3.5%

PSP and batteries have a similar financial risk profile as wind and energy under the base scenario. Their hurdle premium is slightly higher than for PV and wind to compensate for the higher technology risk (large scale battery projects are rather new leading to an increased technology risk) and model risk as demonstrated in the previous section. Moreover, over the years, there is also a significant degradation risk for batteries.

4.4.3. Keeping an old CCGT in the market or keeping an existing CCGT in the market without refurbishment: Hurdle premium of 3.5%

Risk of lower than expected returns under base scenario: low Very high but, because of the short horizon of 3 years, a significant part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as CCGTs, in the forward markets. There is model risk attached to this, given that the hedging analysis uses simulated spot prices, whereas there is no perfect one-to-one link between the forward prices.

Risk of lower than expected returns due to model and policy risk: Medium. These technologies have a high sensitivity to the model assumptions such as the situation of inadequacy of the energy market, the FOM costs and imposing ceilings on returns and /or inframaraginal rents. The risk is reduced by the short horizon of 3 years.

4.4.4. Investing in an existing OCGT in the market without refurbishment: Hurdle premium of 3.5%

Risk of lower than expected returns under base scenario: low Very high but a significant part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as OCGTs, in the forward markets.

Risk of lower than expected returns due to model and policy risk: Medium. These technologies have a high sensitivity to the model assumptions such as the impact of high prices on the merit order (gas before coal vs coal before gas) and the status of (in)adequacy of the market. Also a tax-based ceiling on the project return has a large impact. The risk is reduced by the short horizon of 3 years.

4.4.5. Investment in low activation cost DSM 300: Hurdle premium of 4%

Risk of lower than expected returns under base scenario: Medium. There is a high variability in returns because of the dependence of activation on prices exceeding the DSM activation threshold. Such dependence is inherent to a DSM investment project and somewhat desirable from an operational perspective. Accounting for such state dependent preference implies discounting the "high risk profile" from a pure unconditional risk assessment to "medium".

Risk of lower than expected returns due to model and policy risk: Low-Medium. The profitability of an investment in new demand response is impacted. An important impact is the risk of a (perceived) implicit or explicit price cap would decrease the asset's profitability in a detrimental way, given that its business case is driven by the occurrence of price spikes.

The impact of model and policy risk for demand response capacities is considered lower compared to gas-fired installations, given that the economic lifetime is shorter (around 3 years) and there is no substantial CAPEX involved.

The impact of all these different scenarios, combined with the shorter (compared to other technologies) economic lifetime of 3 years, results in a "low-medium" assessment for this parameter for new DSM300.

4.4.6. Investment in medium activation cost DSM 500: Hurdle premium of 4.25%

Same as for DSM300 but with a higher activation threshold and thus a higher financial risk of lower than expected returns. Probability of zero inframarginal rents in a given year is 38%.

4.4.7. Keeping an existing/old CCGT in the market with refurbishment: Hurdle premium of 4.5%

Risk of lower than expected returns under base scenario: Medium. A small top-up is given to compensation for the observed risk under the base scenario. The compensation for that risk (above what is already included in the reference WACC) is small given the possibilities for hedging part of that risk on forward markets (cf. previous section for more explanation on the impact of hedging).

Risk of lower than expected returns due to model and policy risk: Medium-high. The investment horizon is 15 years implying that when the existing CCGT is in operation, the conditions of the base scenario may no longer hold. There can be a lower price bound, more competition (e.g. resulting in changes in the merit order), higher costs. Their impact on the expected return is substantial and therefore justify the hurdle premium compensation for model and policy risk.

4.4.8. Investment in high activation cost DSM 1000/2000: Hurdle premium of 4.75%

Risk of lower than expected returns under base scenario: Medium-high. The analysis has demonstrated that the downside risk is "very high" for the high activation cost DSM. They are dependent on price peaks, and have a high probability of zero yearly inframarginal rents. Such dependence is inherent to a DSM investment project and somewhat desirable from an operational perspective. Accounting for such state dependent preference implies discounting the "very high risk profile" from a pure unconditional risk assessment to "medium-high".

Risk of lower than expected returns due to model and policy risk: Medium. The profitability of an investment in new demand response is impacted. An important impact is the risk of a (perceived) implicit or explicit price cap would decrease the asset's profitability in a detrimental way, given that its business case is driven by the occurrence of price spikes.

The impact of model and policy risk for demand response capacities is considered lower compared to gas-fired installations, given that the economic lifetime is shorter (around 3 years) and there is no substantial CAPEX investment (around 3 years).

The impact of all these different scenarios, combined with the shorter (compared to other technologies) economic lifetime of 3 years, results in a "medium-high" assessment for this parameter for new DSM300.

4.4.9. Investment in a new CCGT: Hurdle premium of 5%

Risk of lower than expected returns under base scenario: low. The analysis has demonstrated that the variability in the returns and downside risk is low for new CCGT installations. This variability of the revenue distribution and the downside risk can be further mitigated by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as CCGTs, in the forward markets. Although forward prices usually do not provide a more than three-year forward hedging horizon, which is too short to build a business case for a CCGT[24], future hedging opportunities might reduce investor's uncertainty as variability on historical forward prices is lower compared to spot prices. In addition, at the moment of the investment decision, given the time to construct such a CCGT unit (which takes 2 or 3 years), no forward contracts are available on which the investment can be hedged.

Risk of lower than expected returns due to model and policy risk: high. The profitability of an investment in a new CCGT is highly impacted by the use of different scenarios. Thermal capacities, such as gas-fired installations, particularly run the risk that policy measures might impose stricter requirements on their operations in the future (e.g. the obligation of a minimum share of "green" fuel). Alternatively, such policies might ban these installations altogether). In addition, the business plan of gas-fired installations can also be significantly impacted by policy decisions that stimulate the development of renewable energy sources (e.g. such risk is real in view of the implementation of the Green Deal) as they may directly impact the position of such gas-fired units on the merit order. Moreover, a (perceived) implicit or explicit price cap would further decrease the asset's profitability.

The significant economic lifetime of a CCGT of at least 20 years further aggravates this model and policy risk, given that the uncertainties and associated risks increase over time.

[24] Newbery (2020) formulates it as follows: *"the problem is not that there are no futures and forward markets, only that their tenor is not matched to that needed to reassure financiers lending at an acceptable cost of capital"*

The significant impact of all these different scenarios, combined with the uncertainties related to the modelling of forward prices, and the long economic lifetime of at least 20 years, results in a "high" assessment for this parameter for new CCGTs.

4.4.10. Investing in an OCGT in the market with refurbishment: Hurdle premium of 5.5%

Risk of lower than expected returns under base scenario: high Very high but part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as OCGTs, in the forward markets.

Risk of lower than expected returns due to model and policy risk: Medium-high. These technologies have a high sensitivity to the model assumptions such as the impact of high prices on the merit order (gas before coal vs coal before gas) and the status of (in)adequacy of the market. Also a tax-based ceiling on the project return has a large impact.

4.4.11. Investment in a new OCGT: Hurdle premium of 6.5%

Risk of lower than expected returns under base scenario: High. The analysis has demonstrated that the revenue distribution and downside risk is "high" for OCGT installations, driven by the later position in the merit order book as compared to CCGT

Risk of lower than expected returns due to model and policy risk: Very high.

The profitability of an investment in a new OCGT is impacted by the use of different scenarios (increase in gas prices leading to a change in merit order, reaching adequacy in the market).

Furthermore, thermal capacities, such as gas-fired installations, particularly run the risk that policy measures might impose stricter requirements on their operations in the future (see explanation on CCGTs above). Finally, a (perceived) implicit or explicit price cap further decreases the asset's profitability .

The significant economic lifetime of an OCGT of at least 20 years further aggravates this model and policy risk, given that the uncertainties and associated risks increase over time.

The impact of all these different scenarios, combined with the long economic lifetime of at least 20 years, results in a "high" assessment for this parameter for new OCGTs.

4.5. Implications for economic viability

Given the expected return obtained under the base scenario, the reference WACC and the hurdle premium accounting for policy, model and downside risk, we can now predict the investment decision.

Under a setting similar to the one considered by Elia (2019, 2021) we find that only investing in an existing CCGT is economically viable[25]. All other technologies require a change in the base scenario that would increase expected returns and lower risk, and/or a change in the economic and political environment that would reduce model and policy risk.

[25] Note that these results are only for illustrative purposes and might deviate from the conclusions in Elia's Adequacy and Flexibility Study as Elia's study accounts for additional revenue streams.

Table 16 Summary statistics of investments studied

	E[R] base	lifetime	capex	P(IR=0)	sd	E[R] 25%	E[R] 10yr	E[R] adeq	E[R] FOM	premium	hurdle
New offshore	-0.033	15	2300	0.000	0.003	-0.033	-0.068	-0.036	-0.042	0.027	0.076
New onshore	0.006	15	1000	0.000	0.003	0.006	-0.026	0.002	-0.007	0.027	0.076
New PV	-0.043	15	600	0.000	0.003	-0.043	-0.073	-0.046	-0.053	0.027	0.076
Existing CCGT	0.298	3	0	0.000	0.819	0.083	0.298	0.024	0.142	0.035	0.084
Old CCGT	0.060	3	0	0.000	0.829	-0.096	0.060	-0.184	-0.064	0.035	0.084
PSP	-0.098	25	900	0.000	0.013	-0.098	-0.109	-0.114	-0.104	0.035	0.084
Batteries 2h	-0.120	15	400	0.000	0.020	-0.120	-0.131	-0.144	-0.128	0.035	0.084
Batteries 4h	-0.108	15	750	0.000	0.018	-0.108	-0.144	-0.128	-0.113	0.035	0.084
Existing OCGT	-0.007	3	0	0.040	1.046	-0.202	-0.007	-0.274	-0.130	0.040	0.089
DSM 300	-0.460	3	0	0.166	0.529	-0.508	-0.460	-0.594	-0.519	0.040	0.089
DSM 500	-0.522	3	0	0.377	0.503	-0.563	-0.522	-0.646	-0.574	0.043	0.091
Refurbished CCGT	0.035	15	100	0.000	0.076	0.031	0.022	-0.023	0.008	0.045	0.094
Refurbished old CCGT	-0.013	15	100	0.000	0.081	-0.016	-0.015	-0.070	-0.037	0.045	0.094
DSM 1000	-0.592	3	0	0.482	0.428	-0.619	-0.592	-0.691	-0.635	0.048	0.096
DSM 2000	-0.718	3	0	0.523	0.275	-0.723	-0.718	-0.790	-0.746	0.048	0.096
New CCGT	0.017	20	600	0.000	0.029	0.016	-0.029	-0.018	0.005	0.050	0.099
Refurbished OCGT	-0.095	15	80	0.040	0.068	-0.095	-0.060	-0.149	-0.115	0.055	0.104
New OCGT	-0.045	20	400	0.020	0.052	-0.045	-0.070	-0.089	-0.056	0.065	0.114

Note: Columns correspond to (i) technology, (ii) expected return under base scenario, (iii) lifetime of the investment (in years), (iv) capex (€/kW/y) (v) probability of zero inframarginal rents in a year, (vi) standard deviation of the return, (vii) expected return when returns are capped at 25%, (viii) expected return when lifetime is reduced to 10 years, (ix) expected return under adequacy scenario, (x) expected return when 25% higher FOM, (xi) proposed hurdle premium, (xii) proposed hurdle rate. * For DSM the CAPEX was taken as annualized and included in the FOM (50 €/kW/y).

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