Report on the future contribution of biomass- and waste-fired CHPs to the security of supply and the stability of the electrical grid in Belgium

Introduction

As the share of renewable energy sources in the power grid continues to rise, the need for adequate energy storage and flexible generation technologies becomes increasingly critical. Renewable resources such as solar and wind are inherently intermittent, leading to fluctuations in power availability that can challenge grid stability and reliability. To address these challenges, energy systems must evolve towards solutions that can provide dispatchable and flexible electricity production. This report focuses on exploring how existing Combined Heat and Power (CHP) plants in Belgium, when combined with retrofit measures, can contribute to increased flexibility in the future. Specifically, it aims to evaluate strategies that enhance the dispatchability of CHP-based generation while aiming at high economic feasibility and gaining more upward and downward flexible capacity in the Belgian grid.

According to ELIA's 2024 report, the current Belgian biomass and waste power capacities consist of 615 MW and 334 MW, respectively (Figure 1) (link). ELIA classifies the fuels used in various waste plants as either renewable or non-renewable, non-recyclable waste. The biomass plants included in ELIA's report, such as the cogeneration plant in Langerbrugge, are fueled by a mix of biomass waste streams (e.g., sludge and wood residues) (link). However, as we focus solely on biomass-fueled cogeneration plants, only a portion of the reported 615 MWe capacity is relevant to our analysis[1]. Some of these plants operate on non-solid materials or are electricity-only producers, like the 18 MWe Electrawinds Biomassa plant in Oostende. Therefore, for this study, we consider only a subset of these biomass plants in our representative fleet, specifically those using renewable and non-renewable, non-recyclable solid waste sources for cogeneration.

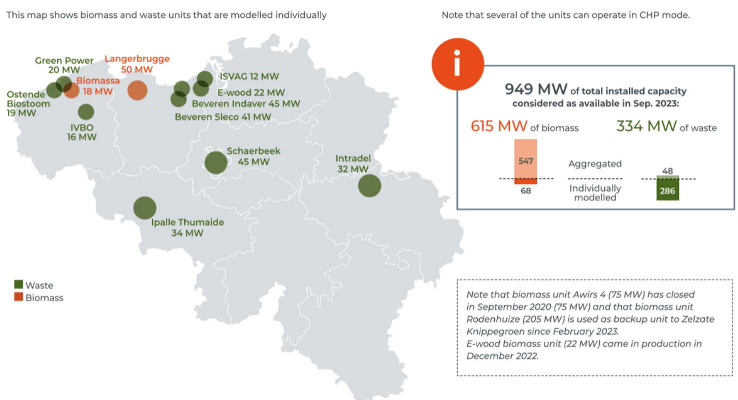


Figure 1: ELIA's aggregated and individually modeled biomass and waste plants in Belgium (link).

[1] As the residual CHP plants are biogas or biofuels, the flexibility of these plants were not considered in the previous work packages and deliverables.

Current and future cogeneration capacity versus availability in 2040

In our initial report (Deliverable 1), *The Energy Potential of Waste and Woody Biomass for Fueling Cogeneration Plants in Belgium*, we estimated that 7.98 TWh of biomass energy potential (excluding primary and tertiary residues) was available in Belgium for cogeneration in 2019. That same year, approximately 8.06 TWh of municipal solid waste was converted into electricity and heat. Based on the plants listed in the report, we identified a total capacity of 319 MWe from municipal waste plants and 301 MWe from renewable biomass plants that are currently operating. When comparing our values to ELIA's report, we observe a discrepancy of 16 MWe for municipal waste plants (334 MWe according to ELIA versus 319 MWe in our analysis). This 16 MWe difference originates from the "aggregated" waste capacity (48 MWe) in ELIA's report, which may include a portion corresponding to plants not listed in the Belgian waste-to-energy federation and therefore not included in our dataset. For the renewable waste-fueled cogeneration fleet, a significant discrepancy exists between ELIA's reported 615 MW and our estimated 326 MW. This difference stems from our more restrictive criteria: we only include plants that (at least partially) use solid forest and agricultural residues (e.g. end-of-life wood) and operate in CHP mode. As a result, many of the biomass plants in ELIA's dataset are excluded from our analysis. We specifically exclude:

- Plants that only produce electricity (e.g., Electrawinds Biomassa in Oostende),
- Units fueled by wood pellets (e.g., the CHP plant at the University of Liège (link) and backup plant Rodenhuize),
- Plants producing and using biogas or biofuels (e.g., AM-Power (link)),
- Decommissioned CHP plants, and
- Facilities with no digital trace confirming their use of wood residues for cogeneration.

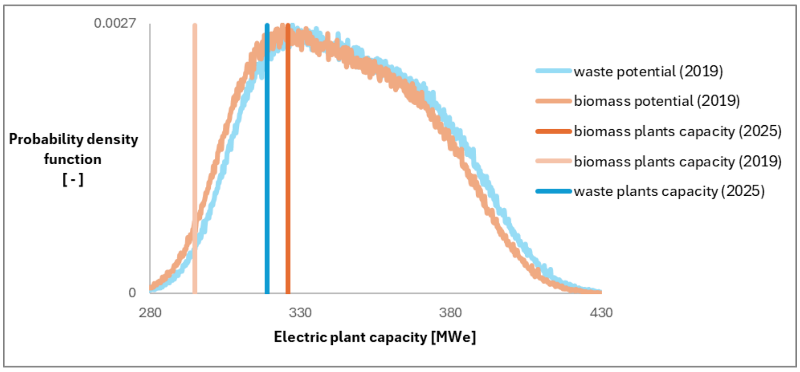
Due to these exclusions, a significant portion of ELIA's biomass capacity is not represented in our analysis. Nonetheless, some included plants do not run exclusively on the waste residues studied in our project. For example, Burgo Ardennes II in Virton operates on approximately 17% wood residues (bark), while the majority (around 67%) of its fuel mix is black liquor. Despite this, we include the full capacity in our representative fleet[2].

Reflecting on our analysis in Deliverable 1, we can compare the theoretical power capacity of biomass plants that exist in 2025 to the estimated energy potential of 2019. Given a biomass energy potential of 7.98 TWh (excluding municipal waste), and assuming an electric efficiency of 30% and a capacity factor of 85%, we calculate a potential biomass

[2] The energy potential of black liquor was not considered in our first report and won't be considered further here in this report.

fleet capacity of 322 MWe. This estimated value is close to the 326 MWe current capacity we identified (excluding municipal CHP plants using woody industrial and household residues). When we examine the CHP capacity of 2019, we observe a capacity of 295 MW. In practice, the low capacity of the biomass CHP fleet compared to its availability resulted in overcapacity of waste wood in Belgium in 2019, as confirmed by OVAM's report (Marktanalyse biomassareststromen 2022). They reported a notable export-import discrepancy of B- and C-wood for energy valorization in 2019, with approximately 211 kton exported versus 48 kton imported. Accounting for this 163 kton net export, and using an average dry LHV of 17.6 GJ/ton (link), we find a reduction of approximately 0.80 TWh in energy potential for Flanders. This reduction translates to the 32 MWe gap in Belgium's electric capacity in 2019. In addition to the existing cogeneration capacity, three projects in Wallonia (Louvain-la-Neuve, Vielsalm and Lixhe) are planned in the future, which will add 46MWe capacity to the grid while at the same time pushing the renewable waste potential demand by 1.13TWh. When performing the same calculation on the non-renewable waste energy potential of 8.06 TWh, it reveals a theoretical electric capacity of 325 MWe, which is also very close to the 334 MWe reported by ELIA and the 319 MWe observed in our own data collection.

When performing an uncertainty analysis on all estimates, modeling the capacity factor as a uniform distribution (70%–90% (link)) and electric efficiency as a Gaussian distribution (mean: 30% and standard deviation: 1%, based on our own study), we find that our estimated capacities fall within the resulting probability density functions (Figure 2). For the non-renewable waste, the energy potential aligns well with the reported capacity. In the case of the renewable biomass, the 295MWe observed capacity (in 2019) falls well below the estimated potential, where the Belgian biomass CHP fleet in 2019 had access to abundant resources, as is confirmed by the report of OVAM. In addition, the current Belgian



CHP capacity of the renewable waste is close to the energy potential of 2019.

Figure 2: The probability density function of the converted energy potential of renewable and non-renewable

waste of 2019 with uncertain load factors and electric efficiencies compared to the deterministic electric capacity of the Belgian CHP fleet for each source in 2019 and 2025.

Following the 2040 prediction by WP1 for the potential of non-renewable and renewable waste energy, a range was observed for each energy source. For non-renewable energy, based on the BWtE study, the potential lies between 10.3 TWh and 7.06 TWh. The current fleet of municipal plants consumes around 7.92 TWh (319 MWe) of waste energy annually. Compared to the indicated range, this implies either an increase in potential requiring an additional plant of about 96 MWe or a decrease in production of around 42 MWe. By the same analogy, the future renewable energy potential lies between 8.78 TWh and 5.44 TWh. In comparison, the existing fleet requires 7.99 TWh (322 MWe) of renewable waste energy each year. These scenarios suggest an average increase of 34 MW_e or a decrease of 109 MW_e by 2040. When analyzing these scenarios, if the non-renewable and renewable waste fleet remains unchanged (in terms of electric and waste capacity) and the energy potential increases, regional waste-to-energy agencies are likely to export this surplus to neighboring countries. Additional plants are considered questionable given Belgium's environmental concerns and local opposition (NIMBY). However, this scenario enables current Belgian cogeneration plants to provide downward flexibility when market signals call for reduced load, e.g. on the day-ahead, intraday, or imbalance markets, or through frequency restoration reserve services. According to ELIA, such downward flexibility, requiring both sufficient reduction in capacity (MWe/15min) and adequate ramp-down speed (MWe/5min), will be increasingly necessary to maintain grid balance as renewables expand and industry decarbonizes (Figure 3). In the opposite scenario, where waste energy potential declines, cogeneration plants would have to reduce their load (lower load factor) to consume less fuel and avoid a complete shutdown. This situation creates opportunities for multiple cogeneration plants to provide upward flexibility to the grid. By reserving a share of capacity, they can respond during periods of insufficient renewable generation or high demand; services that ELIA has identified as critical for the future, alongside downward flexibility (Figure 3). To address this need for both upward and downward flexibility, it becomes essential to determine whether operating in part-load or full-load conditions is more practical and how each mode affects operations, cash flow, and the uncertainty surrounding overall plant performance.

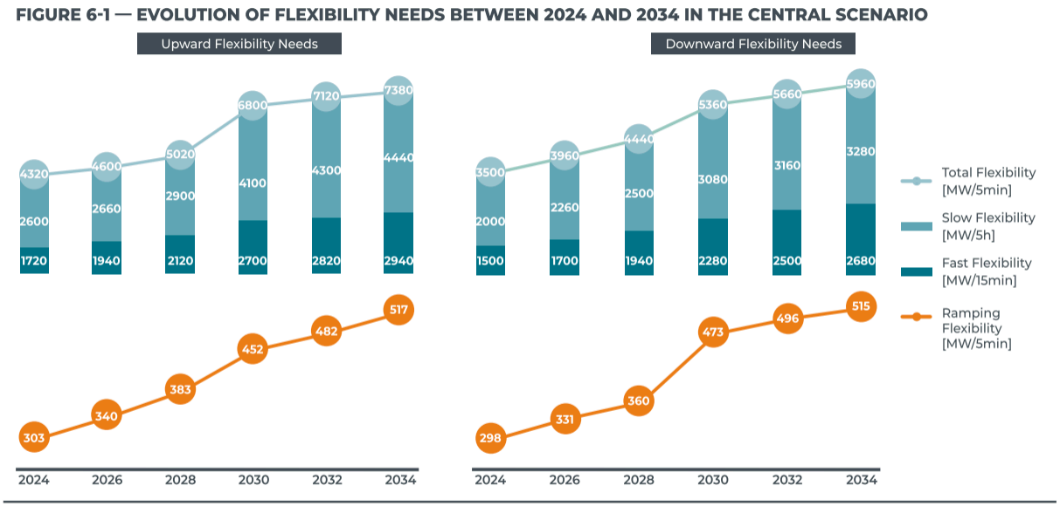


Figure 3: The upward and downward flexible capacity with different time resolutions (15min and 5h) are needed in the future as the non-dispatchable renewable capacity increases. Additionally, the ramping capacity (MW/5min) is also required to achieve the necessary goals for maintaining grid balance (link).

How will the future flexible cogeneration fleet look in practice?

As municipal waste is expected to increase or remain stable in terms of mass flow, as discussed in the report "The Energy Potential of Waste and Woody Biomass for Fueling Cogeneration Plants in Belgium," non-recyclable, non-renewable CHP plants with a total power capacity of 326 MWe will continue to operate at nominal capacity. In the other scenario (decrease in energy potential), the Belgian WtE federation has already stated in an interview that one of the smaller non-renewable waste plants will close, allowing the other plants in Belgium to continue operating at maximum load. As a result, municipal waste plants are not included in the flexible fleet in Belgium and remain 'must-run' thermal plants, as assumed in the ELIA report. For renewable CHP plants, the most likely scenarios are either a continuous supply of the available energy source or a gradual reduction over time. In the first case, current and future CHP plants would operate at maximum capacity, while in the second scenario, part-load operation would become necessary. At present, Belgium continues to maximize the sustainable energy valorization of municipal and renewable waste. However, for the future, the latter scenario is the most plausible, as RED III restricts the use of biomass in energy valorization by prioritizing higher-quality applications such as reuse and recycling, thereby reducing its availability for cogeneration. As renewable waste becomes increasingly restricted under RED III, the price of these resources could potentially rise in the future and while demand remains stable or even increases, this threatens the continuous operation of existing Belgian plants (Figure 4). Political directives have already impacted existing plants in Belgium, resulting in the closure of biomass-fired (pellet and woody waste) power plants due to the revocation or non-extension of support mechanisms. Notable examples include the biomass plants in Les Awirs and Rodenhuize, and more recently, in 2023, the stalling of 2Valorise's Ham CHP plant. These projects demonstrated that, over time, with rising costs, stricter environmental regulations, and a dependence on policy-driven support mechanisms, the economic and operational viability of these plants was increasingly challenged. Therefore, the operation of the current CHP fleet should be modified to support the energy transition, while its economic performance should become more robust in response to these uncertain parameters.

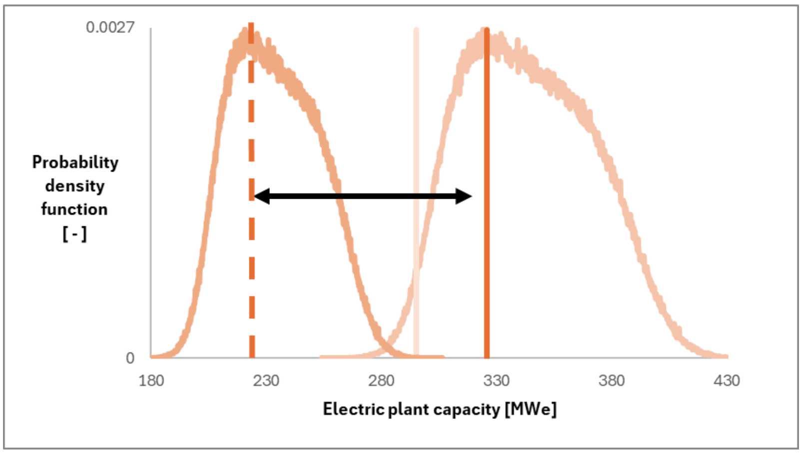


Figure 4: A decrease in Belgium's biomass potential could reduce the total electric power capacity from woody waste-fueled CHP plants when the current range in capacity factor and efficiency is considered. This analysis shows that through this decrease a need for current CHP plants to reduce their capacity factor (below 70%) or increase their electric efficiency (which is limited in terms of technology).

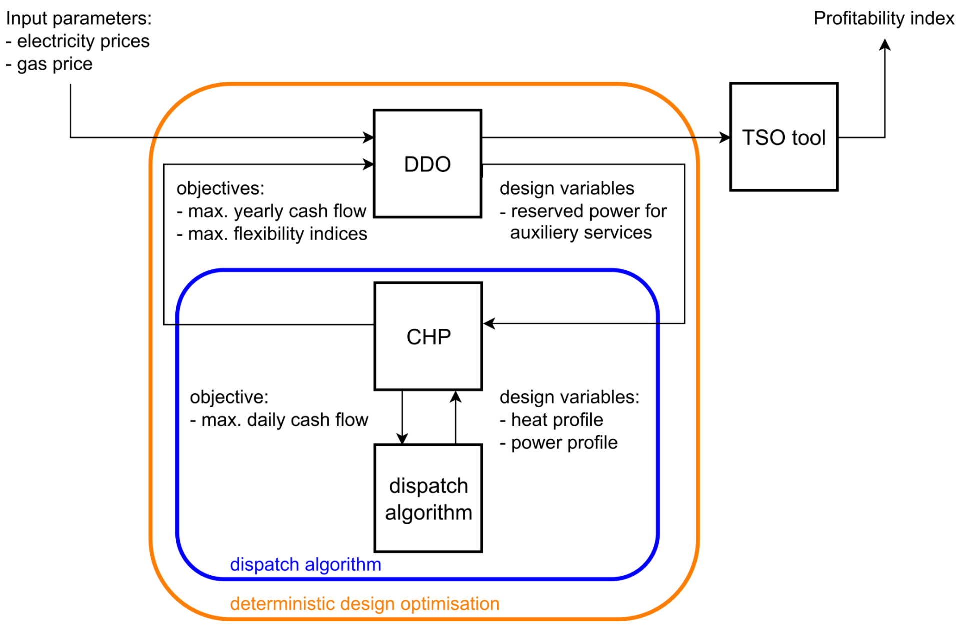
Case study methodology

To prescribe the best configuration and operation, we conducted multiple case studies to show the impact of implementing specific flexibility measures on the operation of an existing CHP unit (Ham's CHP plant with a representative model). In this section, we first discuss the optimal configuration and operation for these CHP plants (Table 1). Afterward, we include the impact of uncertainties (see section Uncertainty quantification). In this section, we considered the potential risks and changes of key parameters that affect the feasibility of retrofitting cogeneration units for the future.

Table 1: Tested case studies where certain combinations of input parameters and flexibility measures were considered.

Case	Direct and indirect elements in the dispatch algorithm				Comment
	day-ahead price	imbalance price	fuel cost	additional flexibility measures	
base	x				TD+a full year
1	x			x (3%/min)	TD
2	x			x (6%/min)	TD
3	x		x	x (3%/min)	TD+a full year
4	x		x	x (6%/min)	TD
5	x	x		x (3%/min)	TD
6	x	x		x (6%/min)	TD
7	x	x	x	x (3%/min)	TD
8	x	x	x	x (6%/min)	TD

We analyzed the retrofit options for this plant based on the toolbox presented in (link) and assessed the plant's technical constraints. From this assessment, we derived a list of retrofit options and linked it to investment costs. This list enables us, depending on the measures, to increase the ramp rates, which is the focus of this study, allowing the plant to participate in different markets and potentially provide accelerated services. However, we did not include other measures, like faster startup (hot, warm and cold), decreasing the minimum power limit, where the document of Then et al., which is also described as a part of the flexibility measures in their study. For this study, we considered the following flexibility retrofit measures namely, additional temperature measurements, a thermal model, optimization of control loops, and an advanced process control loop. To achieve a reliable ramp rate of 3%/min, we assumed that additional temperature measurements are necessary to evaluate thermal stress during load variations, using a model-based thermal stress calculator. This calculator can provide, via a dynamic model, the physical constraints, as shown in the work of (link). Lastly, to achieve a 3% minimum ramp rate, the existing control loops are fine-tuned at the nominal load. In a market price-based operation, the new operating points will vary and move away from the nominal point. When also considering a ramp-rate extension, where an advanced control loop increases the ramp rate capability, like in the work of (link)(link), which allows the plant to operate above the 3%/min range and theoretically to 6%/min. These ramp rates can be achieved by adopting a control system described in (link), where the boiler and turbine follow modes can provide ramp rates of up to approximately 6%/min. Above this ramp limit, the steam pressure overshoots the safety margin for the turbine, which would send a pressure wave throughout the turbine (potentially increasing degradation and damage to the turbine blades) (link). Studies show alternative ways to enhance the CHP's ramp rates via a bypass (link) (link) or by temporarily storing the steam towards one of the turbine stages with thermal energy storage (link) (link). The turbine bypass will divert the steam to the condenser, the district heating heat exchanger, or release it into the atmosphere. This option was deemed infeasible because the enthalpy of the bypassed steam could not be effectively recovered, and the existing condenser and heat exchanger are not dimensioned to handle the additional steam flow under bypass conditions. For the thermal energy storage measures, the existing turbine did not support an additional inlet stream of low-pressure, low-temperature steam, which is usual for low-power CHP plants. In addition to the proposed retrofit measures, further construction and repairs are necessary to enable the existing plant to operate flexibly. We considered investment costs for each of these measures.



Our two-step optimization framework enables us to determine the optimal operating setting for the CHP unit and the additional services it can provide following reconstruction. In the first step, via the deterministic design optimization algorithm of RHEIA (link), a three-objective optimization is performed, where it maximizes the total yearly Cash Flow (CF), i.e. the sum of all revenue streams minus the sum of all operational costs, and the upward and downward flexibility index. These two indices quantify a system's ability to increase or decrease the power supply demand in response to an external signal, i.e. providing aFRR and mFRR services. In this phase, the maximum and minimum power dedicated to each market (day-ahead or imbalance) are the design variables. These ranges are necessary for the dispatch algorithm (the second step) to determine, for each period, the optimized heat and power schedule, utilizing an additional genetic algorithm to maximize the cash flow for each period.

To assess the feasibility of retrofitting existing cogeneration units, we introduce the Profitability Index (PIretrofit), which measures the positive or negative impact of flexibility measures (additional investments) on the plant's solvency and financial health (see equations below). This PI describes the ratio of the Net Present Value (NPV), which includes the additional discounted cash flow generated (compared to the business-as-usual case) and the investment cost of the retrofit. When this value is larger than 1, it constitutes a good investment; when equal to or below 1, it makes the retrofit a risky investment. To determine the profitability index of each case, we need to consider the additional revenues from the upward and downward flexibility indices. To estimate these revenues, we integrated the results of the design optimization variables (maximum and minimum power) of the four DDO cases in the Whattshappening tool of the Belgian TSO (ELIA). Via this tool, we determined the monetization of the upward flexibility and the downward flexibility, where we retrieved the additional revenue stream from aFRR, mFRR and CRM services. The tool incorporates user-provided plant data, historical market data and simplifications for relevance. It enables an initial assessment of CHP suitability as a flexible grid unit. Via this tool, we determined the monetization of the upward flexibility and the downward flexibility, where we retrieved the additional revenue stream from aFRR, mFRR and CRM services. We assumed that these additional revenues remain each year and so are incorporated in the yearly cash flow, NPV

$$\mathrm{PI}_{\mathrm{retrofit}} = 1 + \frac{\mathrm{NPV}_{\mathrm{net,retrofit}}}{C_{\mathrm{retrofit}}} [-]$$

$$\mathrm{NPV}_{\mathrm{net,retrofit}} = -C_{\mathrm{retrofit}} + \sum_{y=1}^{N} \frac{\mathrm{CF}_{\mathrm{retrofit}} - \mathrm{CF}_{\mathrm{base}}}{(1+i)^{y}} [\mathrm{k€}]$$

$$\mathrm{CF} = R_{\mathrm{electricity}} + R_{\mathrm{heat}} - C_{\mathrm{fuel}} - C_{\mathrm{operational}} [\mathrm{k€}]$$

and finally in the PI of the retrofit.

Besides the assessment for investing in flexibility measures, to reduce the computational load of simulating the yearly cash flow, we adopted the Typical Day (TD) approach. This method utilizes a machine learning algorithm to aggregate time series of prices (for gas and electricity) in typical periods (link). This method clusters time series data (e.g., hourly load and generation profiles) into a limited set of representative days, each weighted to reflect its frequency of occurrence, thereby preserving key temporal patterns while reducing the number of time steps. We adopted this method from Hoffmann et al. (link), which describes the development of a Pareto-optimal temporal aggregation framework that jointly optimizes the number of typical days and the intra-day temporal resolution. Their iterative algorithm incrementally refines temporal detail in the direction that yields the greatest reduction in error per additional time step, thus balancing model accuracy and computational effort (link) (link). From this framework, we adopted 7 typical periods of 24 setpoints for each market (electricity or heat), using the hierarchical cluster analysis method, combined with a new cluster method to incorporate the peaks (minimum and maximum) in electricity prices. Depending on the case, we considered this method on the input based on the day-ahead or the imbalance market, combined with the other input parameters, i.e. gas price and fuel price/quality. This method significantly reduces the input data for computational models, thereby decreasing the overall computational time required for the optimal scheduling of the dispatch algorithm.

Base case (business as usual)

Before testing the new revenue streams, we first determine the financials of operating a CHP plant conventionally. Here, we take the base CF and use this CF to compare the changes in CF when we implement the additional flexibility measures. In the cost, we only included the fuel cost, while other cost (e.g. labor cost) is included later on (during the postprocessing). All combinations tested via our framework are considered in conjunction with electricity prices (day-ahead and imbalance) and natural gas prices from 2024. We assumed a waste-wood price of €30/tonne (link) and its quality (lower heating value) based on the measurement data from 2022 by 2Valorise. This waste-wood quality modeling, spanning over one year, is demonstrated in the paper by Verleysen et al. (2025), where the moisture content of the delivered woody waste residue varies, and the ash content of each delivery is uncertain, impacting the lower heating value of the fuel over time. With these datasets and assumptions, we determined that the base cash flow (CF_{base}) of the studied cogeneration plant, operating on woody waste residues at nominal load, is 4495 k€. In practice, this value is heavily dependent on the electricity, gas, and biomass market, e.g. the Ukrainian war affected the electricity, gas, and wood waste prices. For this report, we considered the base cash flow to be illustrative of a representative CHP plant and extended it to the representative fleet as well. Applying the TD approach method to the base case, where 5 typical days and 2 extreme days with the highest and lowest electricity (day-ahead) prices were considered, we obtain a CF of 4459 k€, resulting in an absolute error of 37 k€ per year (a relative error of 0.82%).

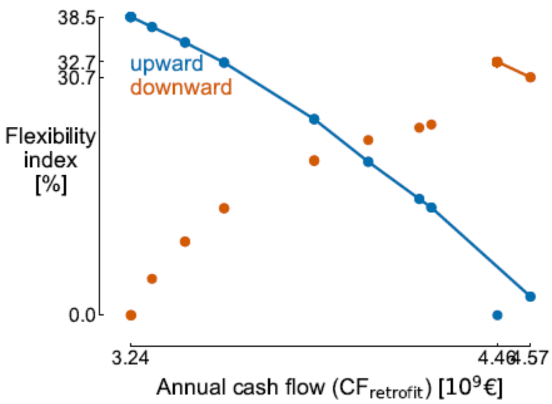
Day-ahead market cases

Cases 1 and 2: 3%/min and 6%/min ramp-rate without live fuel cost

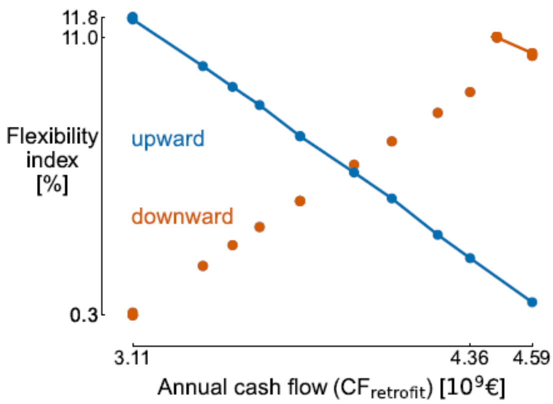
Starting with these cases, the dispatch algorithm optimizes the 24 power and 24 heat setpoints (one for each hour) of the CHP via the cost function. In our case, the cost function is the daily cash flow, where we excluded fuel quality from the cost function and only considered the revenues from heat and electricity (via gas and spot prices). We are excluding the fuel quality as we can assume that the real-time measurement of biomass quality would be expensive. In addition, we integrated flexibility measures to retrofit the CHP unit, enabling us to ramp up and down at rates of around 3%/min and, with an advanced control loop, at rates of around 6%/min. After the dispatch algorithm converges to the most optimal schedule, we calculate the actual cash flow for that period by incorporating the quality of the biomass for the same period. In these cases, we observe a CF increase relative to the base case of 2.89% (to 4591 k€) and 2.96% (to 4595 k€), respectively.

Cases 3 and 4: 3%/min and 6%/min ramp-rate with fuel cost

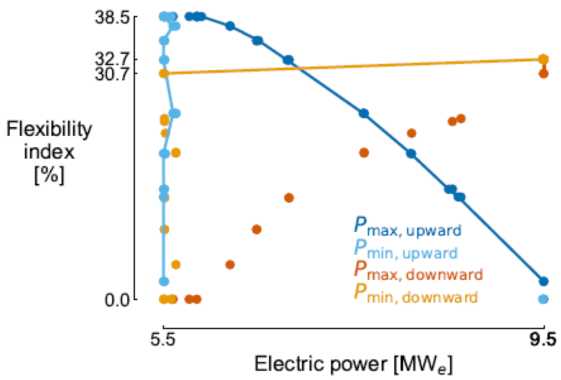
When including the real cost by combining the estimated net calorific value and fuel price, we observe a slight gain in cash flow for the 3%/min ramp rate, at 0.76% relative to Case 1 or 3.63% relative to the base case (4626 k€). For the 6%/min case, this cash flow gain is 0.66% compared to case 2 and 3.61% compared to the reference case (4626 k€). These cases demonstrate that having an approximate pseudo-cost based on samples of the delivered biomass can provide a gain in additional cash flow by comparing the operating cost with the electricity price on the day-ahead market. Due to the ideal conditions, we performed a design optimization of these two cases, determining the optimal capacity reservation for upward and downward flexibility as a function of the respective flexibility indices, while maximizing the yearly cash flow. This optimization reveals the trade-offs between annual cash flow, upward and downward flexibility indices (Figures X, Y and Z). However, we observe that all configurations, as expected, yield lower yearly CF when they do not utilize the entire feasible region of the CHP plant. Therefore, the electric power that is not utilized in the dispatch algorithm is allocated for flexibility, resulting in lower cash flows and is traded to provide more upward or downward flexibility.



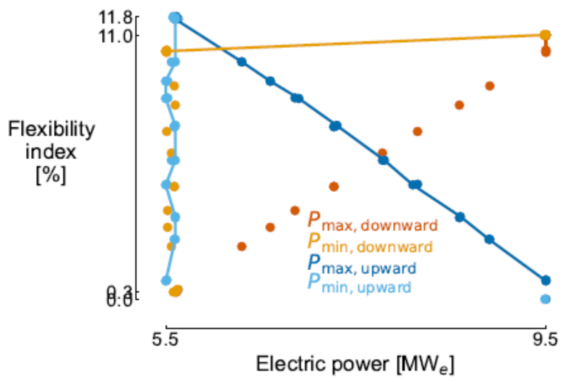
(a) CF for the 3%/min ramp-rate case



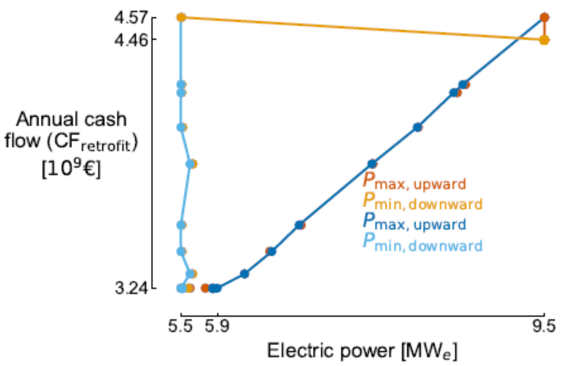
(b) CF for the 6%/min ramp-rate case



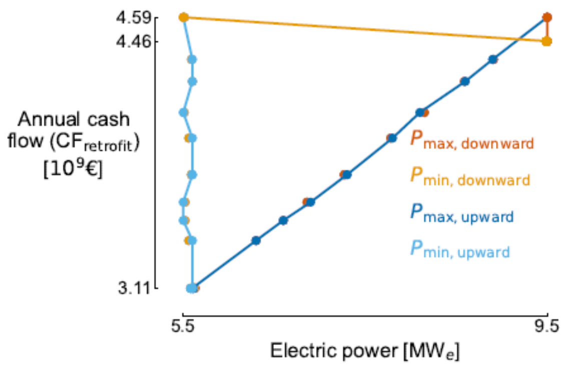
(a) FI's versus the design variables



(b) FI's versus the design variables

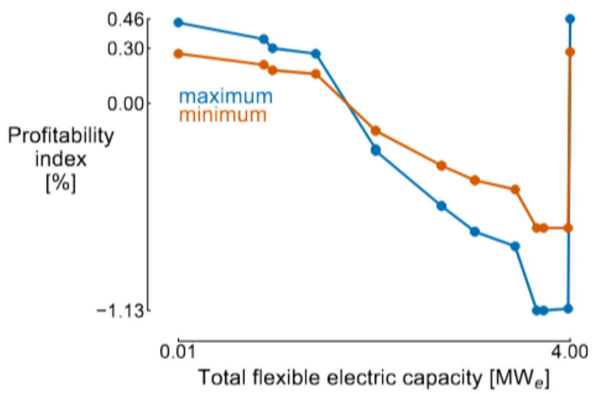


(c) CF versus the design variables

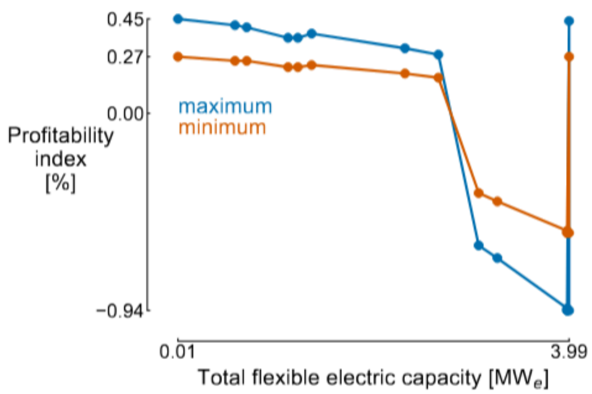


(d) CF versus the design variables

When integrating the results of the design variables (maximum and minimum power) of the DDO in the Whatsshappening tool of the TSO (ELIA), twice; once to monetize the upward flexibility, and secondly for the downward flexibility. With this method, we retrieved the additional revenue stream from aFRR, mFRR, and CRM services. These additional revenues are integrated into the yearly cash flow, without considering the increase or decrease in fuel costs, and are used in calculating the profitability index. In this calculation, we assumed a 10-year lifetime for the investment, a discount rate of 6.4%, and an initial maximum and minimum investment range depending on the ramp-rate requirements (Figure X). Via these investments, we observe that even when excluding the operational cost increase of 10% compared to the base operational cost, no design or case provides a PI of more than or equal to 1; showing that combining the day-ahead market with additional flexibility services and CRM can not create a positive investment for existing biomass cogeneration units after retrofitting.



(a) Trade-off for the 3%/min ramp-rate case



(b) Trade-off for the 6%/min ramp-rate case

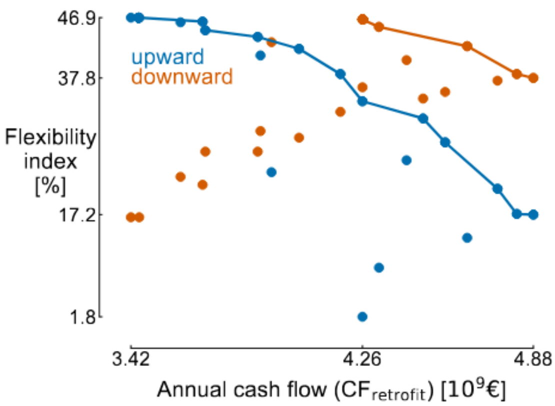
Day-ahead and imbalance market cases

Cases 5 and 6: with 3%/min and 6%/min ramp-rate without live fuel cost

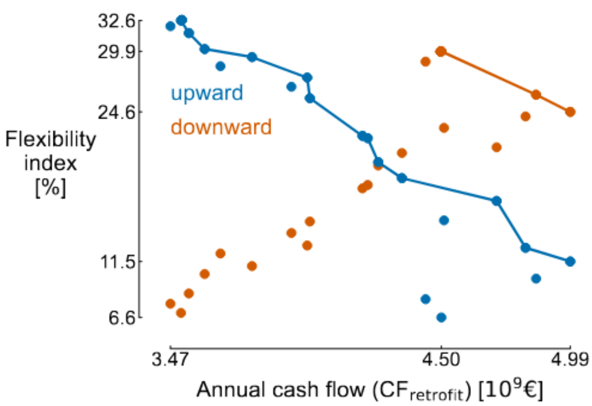
For cases where we optimize the CHP's setpoints using day-ahead and imbalance market prices, four design variables bound the electric power. Two design variables reserve a specific range of power for the day-ahead market. These two design variables are utilized in the first step of the dispatch algorithm to optimize the power schedule in accordance with the day-ahead market. Then, after the day-ahead power setpoints are optimized, a second dispatch optimization occurs, considering the day-ahead power setpoints and the imbalance prices. In this dispatch algorithm, two additional design variables are considered for the bounded setpoints of electric power for trading in the imbalance market. In this case, where live fuel quality and price are not considered in the dispatch algorithm, we selected the entire feasible region. In the case where we assumed a 3%/min ramp-rate, we observe an increase of 8.4% in annual cash flow (4865 k€) relative to the base case. For the 6%/min case, the results reveal a relative increase of 10.6% in yearly cash flow (4989k€).

Cases 7 and 8: with 3%/min and 6%/min ramp-rate with live fuel cost

When including the real-life fuel cost (via the net calorific value and fuel price), we observe a relative gain of 1.4% in annual cash flow for the 3%/min ramp rate (4934 k€) relative to case 5 and an increase of 10.7% relative to the base case. For the 6%/min ramp rate, we observe a rise of 1.8% relative to case 6 and an increase of 14% relative to the base case (5083 k€). As the advantage of considering live fuel cost in the dispatch algorithm is shown in this first analysis, we optimized the power range reservations via the design optimization by maximizing the flexibility indices and the yearly cash flow. Like in the previous cases, a trade-off is observed between these three objectives, where a design with lower annual CF provides for higher (upward or downward) flexibility.

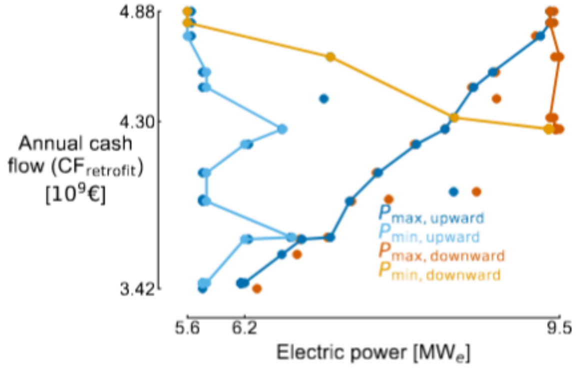


(a) CF for the 3%/min ramp-rate case

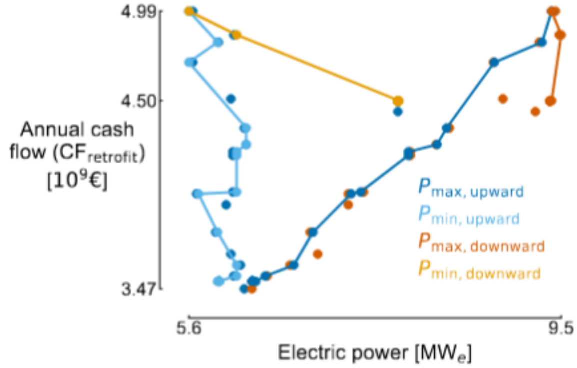


(b) CF for the 6%/min ramp-rate case

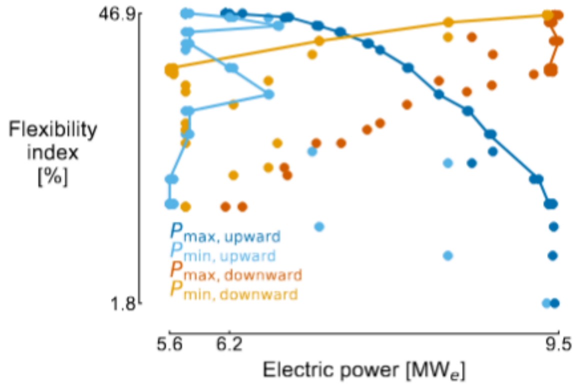
When integrating the results of the Whatshappening tool in the yearly cash flow, and calculating the profitability index with the same assumptions as previously, we observe that only when excluding the operational cost increase of 10%, the retrofit design with a ramp rate above 4%/min allows for a PI of at least 1. When integrating imbalance prices into the dispatch algorithm, and only when the operational cost does not increase, while considering the financial incentive of the CRM each year, we can achieve a positive investment. However, in practice, this operational cost is still expected to grow (e.g. labor cost to inflation and repair and maintenance cost to the plant's load variation) as the plant becomes more complex and the operator's responsibility increases. Due to the price changes in the electricity market, the plant will also undergo (partial) automatic adjustments at 15-minute time steps, which would increase the operation and maintenance costs. Again, as in the previous cases, combining the day-ahead and imbalanced market with flexibility services and CRM support, we found no positive context for existing biomass cogeneration units after retrofitting.



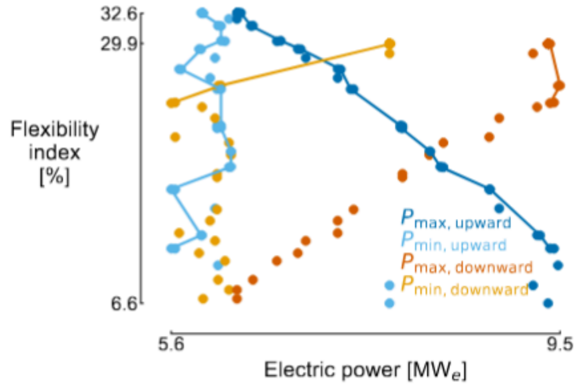
(c) Imbalance limits based on CF (3%/min)



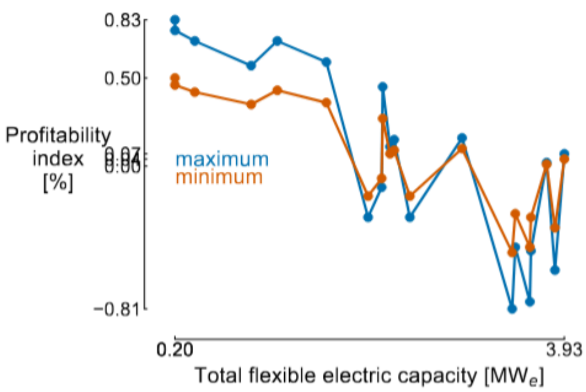
(d) Imbalance limits based on CF (6%/min)



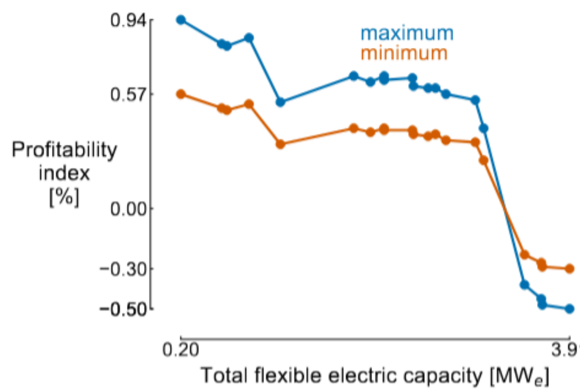
(e) Imbalance limits based on FI's (3%/min)



(f) Power limits based on FI's (6%/min)



(a) Trade-off for the 3%/min ramp-rate case



(b) Trade-off for the 6%/min ramp-rate case

Uncertainty quantification analysis

The results of the DDO in combination with the dispatch algorithm reveal that only in one specific scenario provides for a positive investment, namely when considering the day-ahead and imbalance market, having a plant with a ramp rate of at least 4%/min, considering flexibility services (aFRR and mFRR), and (mainly) integrating the CRM as an additional revenue. However, as in this case, the expected operational cost increase is not considered in addition to uncertainties that could occur during retrofit implementations or operation, e.g. investment cost, fuel quality variations and operational cost changes. The uncertain parameters and their ranges are listed in the table below.

Table 2: Assumed technical and economic parameter uncertainty ranges.

name	min	max	unit	description
discount rate (WACC)	6.4	15.2	%	WACC where risk is included
relative investment cost for retrofit	15.0	25.0	%	part of the total original investment
yearly operation cost (increase)	0.0	8.0	%	part of the base case operational cost
fuel cost	35	60	euro/ tonne	assumed future cost
moisture content	-30	30	%	relative to the mean $MC_{biomass}$
ash content	5	30	%	relative $AC_{biomass}$

To propagate these uncertainties of the technical and economic parameters through the cogeneration model, we implemented the Polynomial Chaos Expansion algorithm. This technique provides a computationally efficient alternative to the Monte Carlo simulation, as we adopted a computationally expensive model. Here, the PCE reduces the time and computational resources needed to determine the mean and variance of the quantity of interest. This section allows us to measure the impact of the uncertainties on the profitability index and quantify the most significant contributors to its variance (via the Sobol' indices).

Based on these initial findings, the design with a 6%/min ramp rate was selected for subsequent uncertainty quantification (UQ). Deterministically, this design yields a PI between 0.85 and 0.52 and provides a total flexible capacity of 0.85 MW, consisting of 0.14 MW downward and 0.71 MW upward capacity. This configuration was therefore used to examine how techno-economic uncertainties influence the feasibility of achieving a flexible retrofit.

The UQ of the PI was performed using a polynomial chaos expansion of order two, which ensured a leave-one-out error (LOOE) below 1 %. The results reveal that the mean PI is 0.63, with a standard deviation of 0.077, and that the probability density function indicates an extremely low likelihood of the PI exceeding unity. Consequently, even when uncertainties are introduced, the expected PI remains within the same range as in the deterministic DDO results, implying a negligible probability of achieving a positive return on investment or even a break-even outcome.

The sensitivity analysis further reveals that the variance in the PI is primarily driven by economic parameters. The retrofit cost, C_{retrofit}, accounts for 48.9% of the variance, while the operational cost, $C_{\text{operational}}$, and the discount rate contribute 26.0% and 25.6%, respectively. In contrast, the fuel cost, moisture content, and ash content have no observable influence on the PI. This behaviour results from the PI formulation, which is based solely on the differential cash flow between the retrofit and business-as-usual scenarios. Since fuel-related parameters affect both cases similarly, their impact cancels out during the NPV calculation and therefore does not propagate to the PI.

To assess how technical uncertainties impact the annual cash flow (CF), a separate UQ analysis was conducted on the retrofitted CHP system. Here, a second-order polynomial expansion resulted in an LOOE of 5.6%, which was considered sufficiently accurate. The analysis indicates that the average annual cost is 2.8 million euros, with a standard deviation of 0.68 million euros. In contrast to the PI results, the fuel-related parameters dominate the uncertainty in CF, with the moisture content contributing 47.4% to the variance, the ash content contributing 27.5%, and the fuel cost contributing 26.5%. These findings are consistent with earlier work, which demonstrates that the physical and economic properties of woody biomass substantially affect operational costs and therefore constitute the primary source of CF variability.

Part 3: Discussion

The results of this study indicate that retrofitting an existing biomass-fired CHP plant does not lead to a favourable economic outcome under current market conditions. This finding highlights the significance of policy interventions and external economic support mechanisms in facilitating the deployment of biomass-based cogeneration, particularly for systems that rely on waste wood as their primary feedstock. Evidence from previous European initiatives suggests that effective sector development typically arises from a combination of quality-based correction factors in feedstock pricing and targeted financial incentives, which together form a stable and supportive policy framework. A central insight from the literature is that the classification of waste wood by quality, as implemented in Germany, allows cogeneration facilities to procure lower-grade feedstock at reduced prices. In some cases, this categorization even results in negative pricing, whereby waste management companies pay biomass plants to process low-value or residual material. Such arrangements reduce operational costs while simultaneously diverting biomass from landfill, thereby contributing to broader circular economy objectives. Financial support instruments such as feed-in tariffs and subsidies further strengthen the economic viability of biomass CHP installations by offering long-term revenue stability and reducing exposure to volatile energy markets. Differentiated feed-in tariffs, designed, for example, to incentivize small-scale plants or systems using waste streams, have proven effective in promoting decentralized and resource-efficient deployment. Structuring tariff schemes to reward high-efficiency CHP production over electricity-only generation enhances resource utilization and mitigates competition with material wood industries. In addition to feed-in tariffs, investment grants and regional support programs, including green certificates and renewable heat premiums, play a critical role in addressing capital constraints and operational challenges, particularly in contexts where feedstock preparation and handling introduce additional costs and logistical complexity. Taken together, current policy analyses and empirical evidence converge on the conclusion that well-designed support mechanisms, specifically quality-adjusted feedstock pricing, tailored feed-in tariffs, and comprehensive subsidy schemes, substantially improve the economic prospects of flexible biomass cogeneration plants. The continued refinement of these instruments in response to technological progress, market dynamics, and tightening sustainability standards has enabled regions such as Belgium and Germany to cultivate robust, competitive, and environmentally sustainable biomass CHP sectors.

Part 4: How to support biomass and waste plants to the Belgian electricity grid?

2Valorise (ENTRAS)

Suggestions on how to support -> conclusion, **more work has to be done**

In this part, describe a support mechanism that can be in place

https://energsustainsoc.biomedcentral.com/articles/10.1186/s13705-018-0157-0#Sec11

"Without harmonization with capacity mechanisms, renewable energy support may lead to inefficient policy and unbalanced energy system development, including, paradoxically, a need for more fossil energy." – Kozlova et al. 2022

What is the price range for this support?

Law changed in 2013 -> Ham is still under the old system; so the 'old' support mechanism works well,

Biogas discussion here: we know how much more or less power capacity (300MW) is-> but only some biomass stream can be used -> but the biogas motors are much faster.

Appendix:

Additional information about wood waste capacity (OVAM)

houtafval 2024

A&S Energie 180.000

A&U Energie 180.000

Overige 272.400 Som van Stora, Biostoom en Sleco

Serrebedrijven 10.000

Schatting BEE Gent 150.000

E-Wood Kallo 170.000

Geplande capaciteit in Wallonië

Vielsalm : 170 kton B-hout (Unilin/Aspiravi) -> 100MWe en 22.5MWth

Lixhe : 85 kton B-hout (BEE Green/CBR)

Louvain-La-Neuve : 55 kton B-hout (UCL/Veolia).

Cases not investigated in this report or not tested with the dispatch

(@everyone, is this interesting, or do we keep it for "Part 3: Discussion" as earlier work and future work?) Describe here that we also considered other cases, but were not tested to model constraints, less representative cases, or already considered in another report.

- Case 10: performance of the CHP plant with imbalance prices and considering information about the real-time cost of biomass + flexibility measures on CHP + consider only a maximal boundary of 1MWe up/down in (next)
- Case with TES: performance of the CHP plant with the day-ahead prices and considering information about the real-time cost of biomass + TES (done), not with the ENTRAS dispatch algorithm
- Case with BESS: performance of the CHP plant with the day-ahead prices and considering information about the real-time cost of biomass + battery (done), not with the ENTRAS dispatch algorithm

Draft

Suggestion of 2Valorise: discuss the case that would work in practice (the adaptation that would seem the most interesting) and the possible timeline of implementing the chosen measures

Suggestions of the 06/06 meeting:

- In what condition/mechanism can a CHP operate in
- What mechanism does the government need to start the CHP’s flexibility, or initiate the feasibility study of the existing fleet
- orders of magnitude for investment
- feasibility studies of CHP Ham plant, "it is not finished"-> we need to make it practical, additional analysis has to be done, execute a test case
- Flexibilization of the bypass is not fully determined-> bypass could be usable -> bypass the turbine heat needs to be used (application required) -> who wants to use this heat -> new activity of Ham is possible on the industry site. (External investor) Potential studies for this bypass. Raising interest in Flanders with new investors
- The GEKKO model can be used when the plant investments are more concrete. System integration can be tested with the framework! Filip “flexibilization is hot” -> follow-up study
- Effects of flexibility on the technical side -> include in the WP6 report (add this point of attention!)