agricultural engineering.eu 81(2), 2026, 102–125
DOI:10.15150/ae.2026.3363

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Biomethane supply costs for highly flexible CHP plants and the impact of gas storage systems

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This study examines the costs of biomethane supply along the entire process chain up to its use in highly flexible CHP plants under the Renewable Energy Sources Act (EEG 2023). The biomethane process chain is modelled on a techno-economic basis and evaluated using the annuity method in accordance with VDI 2067. The calculated supply costs, including grid connection costs at the gas offtake point, range from 9.8 to 13.4 ct/kWh$_{HHV}$. In addition, the impact of a double-membrane gas storage system at the gas offtake point on cost efficiency is analysed. Such a gas storage system decouples the CHP plant's peak gas demand from the maximum gas withdrawal rate from the grid, thereby enabling a reduction of the peak withdrawal relevant for capacity-based grid cost components. The resulting savings in grid-related charges are offset by additional storage costs and reduced electricity market revenues caused by storage-related operational constraints. The latter are quantified through MILP-based dispatch optimisation and incorporated into the cost assessment. In most scenarios, the use of the storage system is cost-efficient, reducing supply costs by up to 1.7 ct/kWh$_{HHV}$, depending on the network usage tariff structure. The magnitude of this cost reduction is driven by grid tariffs, gas storage costs, and electricity market prices. Furthermore, the use of gas storage may expand the number of economically feasible biomethane CHP locations, highlighting the high practical relevance of this study for operational deployment.

Keywords
Highly flexible biomethane-to-power operation, gas storage system, biomethane process chain, techno-economic analysis

The German federal government aims to increase the share of renewable energy (RE) in gross electricity consumption from 54.4 % (as of 2024) to 80 % (Umweltbundesamt 2025). In particular, the substitution of fossil-based electricity generation by variable renewable energy sources, such as wind and photovoltaic (PV) systems, shapes this development. However, weather-dependent generation increasingly leads to a mismatch between electricity supply and demand, requiring a cross-sectoral transformation and increased flexibility of the energy system (Bundesnetzagentur 2017). These structural changes in the power system are already observable today in the form of extreme market events. For example, in May 2025 there were 112 hours of negative wholesale electricity prices, representing a record number of periods in which prices fell below zero due to high supply coinciding with low demand in the market (pv magazine Deutschland 2025). At the same time, so-called "dark doldrums" regularly occur – periods of low wind and PV feed-in – during which electricity generation

received 19 February 2026 | accepted 30 April 2026 | published 17 June 2026

from these renewable sources is very low. Such a scenario occured, for example, at the end of January 2023.

Figure 1 shows the public net electricity generation in Germany during this period, with the dark doldrums phase highlighted in red (Fraunhofer-Institut für Solare Energiesysteme 2025). Both extremes highlight the structural challenges associated with integrating variable RE sources into the power system. In this context, biomethane-fired combined heat and power (CHP) plants can play a distinctive role as flexible, demand-oriented generation units. They utilise biomethane as a renewable gas and can provide electricity and heat independently of weather conditions and in line with demand, thereby potentially contributing to system stability and security of supply. The Renewable Energy Sources Act 2023 is intended to create targeted incentives for the deployment and operation of these biomethane-fuelled CHP plants with very low full-load operating hours (876 h/a) through specific support mechanisms. Despite these incentives, participation in biomethane auction schemes has remained limited so far.

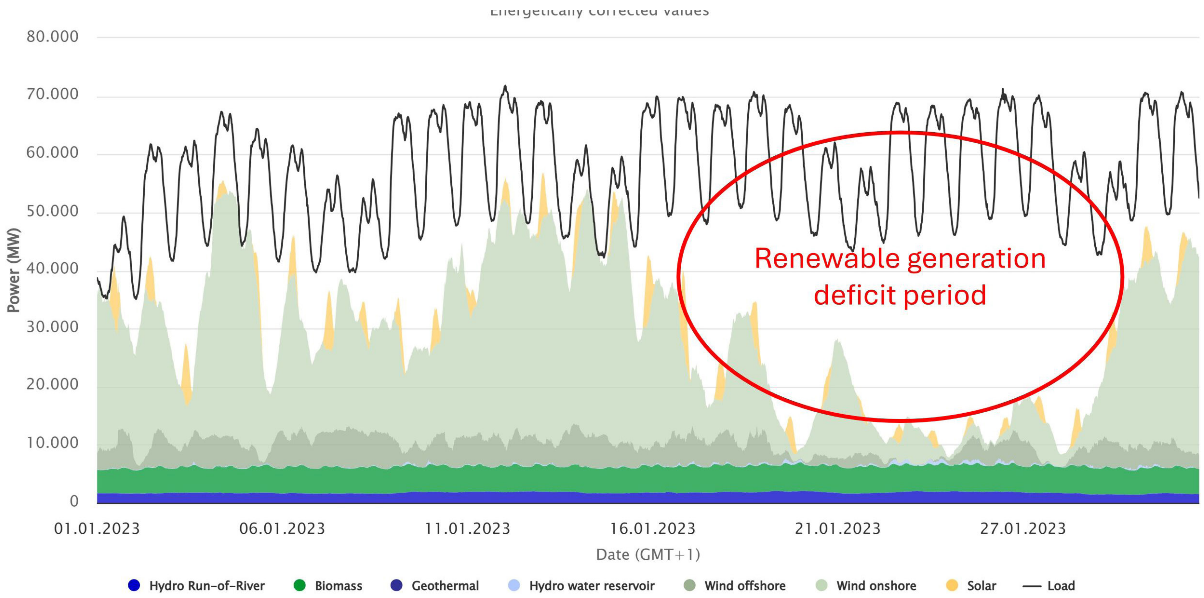

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Figure 1: Public net electricity generation in Germany in January 2023; (Fraunhofer-Institut für Solare Energiesysteme 2025; adapted and supplemented by the author)

Against this background, this study focuses on the analysis of the biomethane process chain, regarding biomethane supply costs and the potential effects of on-site gas storage at the natural gas grid offtake point. Such a gas storage system enables the decoupling of the maximum gas withdrawal rate from the natural gas grid from the gas consumption of the CHP plant. Without gas storage, the CHP plant must cover its full-load operation by drawing the corresponding maximum gas withdrawal rate from the grid. In contrast, the use of storage allows the maximum gas withdrawal rate from the grid to be limited to a lower level, while the required gas volume is additionally supplied from the storage system. As a result, capacity-based grid charges, in particular network charges, can be reduced, and a more balanced gas withdrawal profile can be achieved. However, these benefits are offset by additional storage costs as well as potential operational constraints of the CHP plant, which limit its operational flexibility.

This study addresses the following research questions:

- What are the biomethane supply costs along the process chain, and how do transport modalities for biomethane affect these costs at the gas offtake point?
- Under which conditions is the use of a gas storage system at the gas offtake point cost-efficient in terms of reducing biomethane supply costs?

Methods

Modelling approach and cost structure

To address the research questions, a techno-economic modelling of the biomethane process chains is conducted. Specific supply costs are evaluated in ct/kWh$_{HHV}$ (based on the higher heating value) using the annuity method in accordance with VDI 2067 (Verein Deutscher Ingenieure 2012). Research question 1 is answered by determining the supply costs of the entire process chain for different gas offtake scenarios. Each gas offtake scenario is characterised by a specific CHP nominal capacity as well as corresponding grid pressure level. Research question 2 investigates the conditions under which the gas storage system is cost-efficient. For this purpose, each gas offtake scenario is assigned a set of gas storage scenarios in which storage capacity and maximum hourly gas withdrawal from the natural gas grid (hereinafter: maximum gas withdrawal rate) are varied. Within the model structure, two components are distinguished in order to systematically capture different influencing factors: (i) a component comprising the biogas production plant (BPP), biogas upgrading plant (BUP), and biomethane injection point (BIP), which remains techno-economically identical across all considered gas offtake cases (scenario-independent), and (ii) a component in which biomethane supply costs are determined under varying framework conditions (scenario-dependent). The scenario-dependent cost structure for direct CHP connection to the natural gas grid comprises the following cost items:

- Natural gas grid – transport and trading:
  Network usage charges, levies, and charges related to biogas balancing.
- Grid connection:
  Costs associated with the physical connection to the natural gas grid.

For scenarios involving the use of gas storage, the following additional cost components are considered alongside reduced network usage charges (corresponding to the respective assumed maximum gas withdrawal rate):

- Gas storage:
  Costs associated with the gas storage system, in particular capital expenditures depending on storage capacity.
- Opportunity costs due to operational flexibility constraints:
  Due to limited gas availability, the operational flexibility of the CHP plant is restricted compared to a plant configuration with direct connection to the natural gas grid without gas storage. This results in a difference in electricity market revenues, which is referred to in this study as opportunity costs.

Figure 2 schematically illustrates the cost structure of the two configurations for the same gas offtake case: on the left without gas storage (direct CHP connection to the natural gas grid), and on the right with gas storage deployment. An exemplary gas storage is shown that results in a reduction of specific biomethane supply costs. The specific costs of biogas production, biogas upgrading, and biomethane injection (scenario-independent component of the process chain) are independent of the use of gas storage. Therefore, these cost components are not included in the assessment of the cost efficiency of the gas storage system.

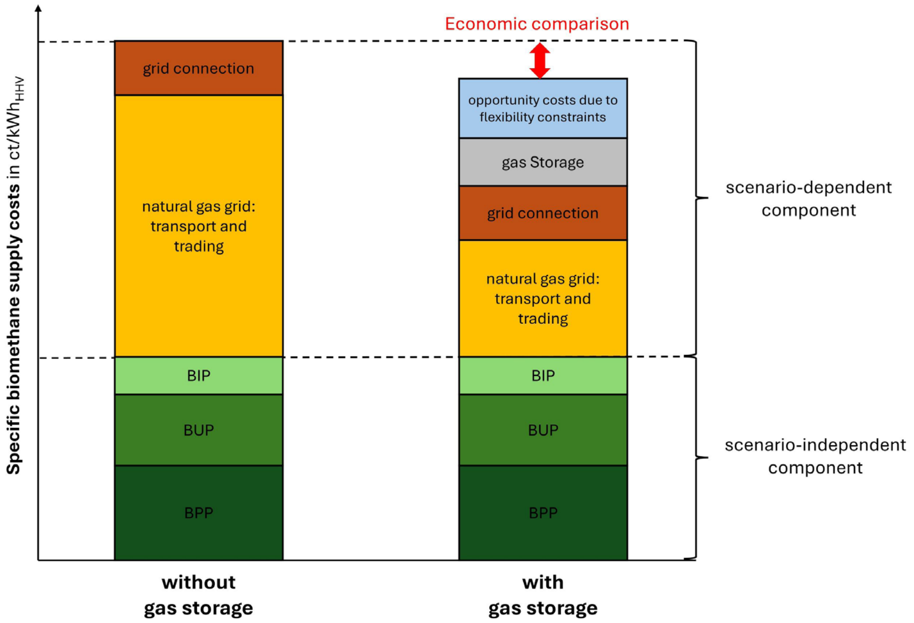


Figure 2: Comparison of specific biomethane supply costs with and without on-site gas storage at the natural gas grid offtake point

Scenarios and Parameter Assumptions

To assess the cost efficiency of gas storage deployment, different scenarios are defined. Table 1 presents the selected parameters: CHP capacity, grid pressure level, gas storage capacity, and maximum gas withdrawal rate from the natural gas grid. The grid pressure levels (1 bar, 4 bar, 16 bar) were selected in consultation with industry experts (J. Gieß, personal communication on exchange on the gas offtake-side grid connection, 21 Mar 2025) as representative gas offtake cases. The maximum gas withdrawal rate from the natural gas grid is defined in discrete steps for each CHP nominal capacity and is scaled proportionally to the respective full-load gas withdrawal rate. The analysed range extends from 19 to 84 % of the full-load gas withdrawal rate of the respective CHP unit. This range lies above the minimum gas withdrawal rate required for providing the annual gas demand corresponding to 876 full-load operating hours (10 % of the full-load gas withdrawal rate) and below the full-load gas withdrawal rate, which defines the maximum gas demand of the CHP unit.

The considered gas storage capacities – also linearly scaled according to CHP size – range from 3,000 to 30,000 Nm^3 in discrete steps. The upper limit of the analysed gas storage capacity was deliberately set at 30,000 Nm^3, as larger storage solutions in practice are associated with new challenges regarding land area requirements as well as permitting aspects, and therefore currently have only limited practical relevance (N. Blume, personal communication on gas storage at the natural gas grid connection (offtake side), 14 Apr 2025).

Table 1: Overview of scenario parameters

CHP capacity in MW_{el}	**Grid pressure level in bar**	**Gas storage capacity in Nm^3**	**Maximum gas withdrawal rate in Nm^3/h**
5	1, 4, 16	3,000–30,000 (Δ 1,000)	200–900 (Δ 100)
10	1, 4, 16	6,000–30,000 (Δ 2,000)	400–1,800 (Δ 200)
20	1, 4, 16	12,000–30,000 (Δ 4,000)	800–3,600 (Δ 400)

Note: The required gas withdrawal rate of the CHP unit at full load amounts to approximately 1,075 Nm^3/h for 5 MW_{el}, 2,150 Nm^3/h for 10 MW_{el}, and 4,300 Nm^3/h for 20 MW_{el}. The calculation is based on an electrical efficiency of 45 % and a higher heating value of natural gas of 10.337 kWh_{HHV}/Nm^3 (Cerbe and Lendt 2017).

Considered Biogas Production Costs

For biogas production costs, a representative reference value of 6.5 ct/kWh_{HHV} is applied. This value lies within the range of typical cost structures observed for agricultural biogas plants, taking into account different plant sizes, technologies, and substrate compositions (Adler et al. 2014, Holzhammer 2015, Schröer and Latacz-Lohmann 2022). To account for uncertainties in long-term cost development as well as plant- and substrate-specific variability, an extended range of 5.0 to 8.0 ct/kWh_{HHV} is additionally considered in a sensitivity analysis.

Modelling of the Biogas Upgrading Plant (BUP)

The modelling approaches for the BUP as well as the subsequently considered BIP are based on the approach presented in Holzhammer (2015). To represent an average BUP, a mean upgrading capacity of 1,400 Nm^3/h of raw biogas is assumed. The five most widely applied upgrading technologies – pressure swing adsorption (PSA), water scrubbing, amine scrubbing, membrane separation, and polyethylene glycol scrubbing – are weighted according to their respective market penetration to represent the characteristics of a representative average plant (technology-specific parameters are provided in Table A1 in the Appendix). The available investment data for different upgrading capacities (Beil et al. 2019) are first adjusted to 2023 price levels using price indices for process engineering machinery and equipment provided by the Federal Statistical Office (Statistisches Bundesamt 2023). Subsequently, following the approach proposed by (Fachagentur Nachwachsende Rohstoffe e.V. 2024) a hyperbolic curve fitting is performed to derive a continuous, weighted cost function, from which the investment costs for the selected reference capacity of 1,400 Nm^3/h can be obtained (Figure 3).

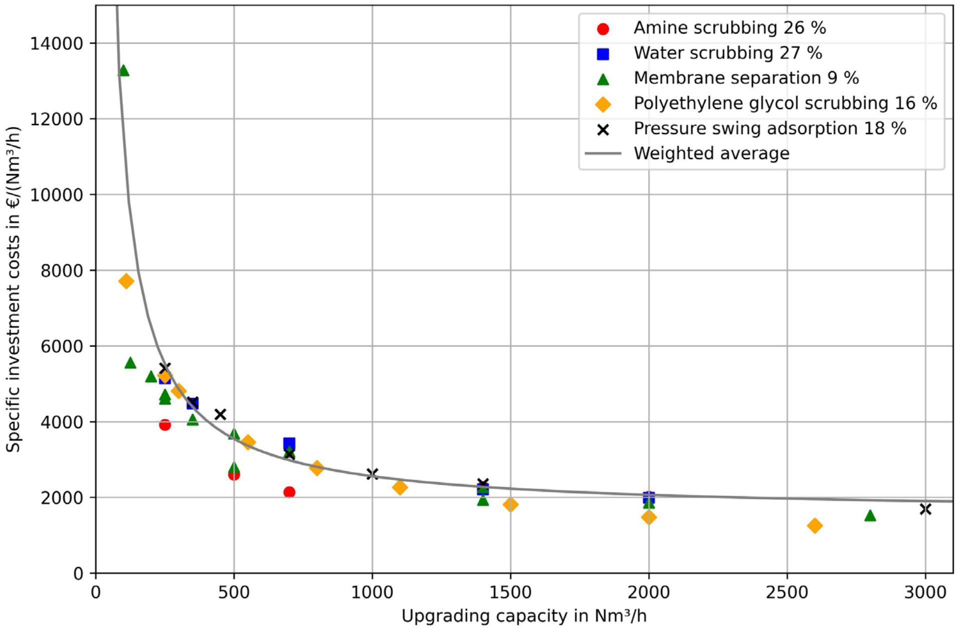


Figure 3: Specific BUP investment costs as a function of upgrading capacity (raw biogas)

The electricity costs assumed for non-household consumers are based on data from the Federal Statistical Office (Statistisches Bundesamt 2024) and are continuously modelled using curve fitting in order to capture cost degression effects. Maintenance, repair and insurance costs are based on standardised shares of investment and ancillary construction costs (Beil et al. 2019). Maintenance costs are assumed to amount to 2 % of the investment costs and 1 % of the ancillary construction costs. Repair and servicing costs amount to 2 % of the investment costs, while insurance costs are assumed to be 0.5 % of the investment costs.

Modelling of the Biomethane Injection Point (BIP)

For the assessment of the biomethane injection facility (BIP), operating costs are considered in accordance with Section 33 of the German Gas Grid Access Ordinance (GasNZV), which applies to existing installations commissioned until the end of 2025. For the modelling of the BIP, two injection cases are considered: grid pressure levels of 1 bar and 16 bar, as these are documented as commonly implemented injection cases (Beil et al. 2019). These two technical configurations are used to represent a realistic cost range. A plant availability factor of 96 % is assumed in accordance with the GasNZV, along with a pipeline connection length of 3 km. Both BIP configurations are designed with an injection capacity of 700 Nm^3/h, corresponding to a typical medium sized plant. Detailed data on investment and operating costs, as well as their percentage allocation between connection customers and network operators, are presented in Table A2 in the Appendix. The data are based on information from Beil et al. (2019) and Urban (2010) as well as expert consultations with industry representatives (M. Buck, personal communication on assumptions regarding cost components of the biomethane injection point, 15 Oct 2024). Investment cost items are calculated based on an operating lifetime of 15 years. Exceptions to this are costs associated with pipeline infrastructure, planning and permitting, as well as the construction of the gas installation building.

For the injection case into the 16-bar grid pressure level, a redundantly configured compression unit is assumed. Electricity consumptions costs are determined based on the ideal electrical energy demand of an isentropic compression process, considering the mass flow rate, pressure increase, and plant-specific process parameters.

Grid Connection (at the gas offtake side)

The considered gas offtake case is included in the grid connection cost assessment. Investment costs are differentiated according to the grid pressure level (Table A3, provided in the Appendix). In addition, operating costs for the connection customer are considered, assuming a labour requirement of 0.5 h/month and labour costs of 75 €/h (gross employer costs). For the gas offtake case from the 16-bar grid pressure level, heat supply costs for gas preheating due to the Joule-Thomson effect are additionally taken into account. This is based on a calculation assuming isobaric heating of the gas stream in the preheater followed by isenthalpic throttling, considering the respective gas withdrawal rate.

Gas Storage Costs

The specific investment costs of the gas storage system in €/m^3 are derived based on an empirical cost function presented in Dotzauer (2024). This function describes double-membrane gas storage systems for the on-site power generation of highly flexible CHP plants and represents the costs as a function of the storage volume V_S and the installed electrical capacity P_{el} of the associated CHP unit (Equation 1)

$$C_{\mathrm{GS\_spec}} = 7.77 + \frac{-8.96 \cdot 10^6}{-106 \cdot V_{\mathrm{S}}} + \frac{-4.26 \cdot 10^5}{605 \cdot P_{\mathrm{el}}} \qquad \text{(Eq. 1)}$$

In addition, the costs are updated to the 2023 price level using the same methodology applied for the BUP. To account for the effect of elevated gas temperatures of up to 35 °C on the usable normalised gas volume, the gas storage system is oversized by approximately 10 % within the cost assessment. This approach follows the equation presented in Bär et al. (2022) for adjusting the usable gas volume under standard conditions. Land and civil engineering costs are assumed to amount to 25 % of the total investment costs, based on common industry estimates.

Opportunity Costs due to Operational Flexibility Constraints of CHP Operation

The CHP plant's electricity generation follows electricity market prices, considering the 876 full-load operating hours permitted under the EEG. An annual dispatch optimisation forms the basis for quantifying the electricity market opportunity costs associated with the deployment of the gas storage system. Compared to the direct connection of the CHP plant to the natural gas grid, operation is constrained by the amount of gas available in the storage system and the operator-defined gas withdrawal rate from the natural gas grid. As a result, the flexibility of the CHP plant and its ability to respond to electricity price signals are limited, which must be considered in the assessment. To quantify these costs, a dispatch optimisation is performed for each gas storage scenario. The resulting electricity market revenues are compared with those of the corresponding reference scenario, consisting of the same CHP nominal capacity with a direct connection to the natural gas grid. The resulting difference is incorporated into the cost assessment of the gas storage scenario as an annuity. The optimisation problem is formulated as a mixed-integer linear program (MILP) and implemented in Python. The model is solved using Gurobi Optimizer version 11.0.3 (Gurobi Optimization LLC 2026). The solver parameter MIPFocus was set to 1, while all other parameters were kept at their default settings. The dispatch optimisation is formulated according to Equation 2. The analysis period is discretised into hourly intervals ($\Delta t = 1\mathrm{h}$). $T = 8760$ for a regular year and $T = 8784$ for a leap year. In each time interval t, the electrical power $P_{\mathrm{el},t}$ is multiplied by the time step and the corresponding electricity price p_t. The sum over all intervals yields the maximum achievable electricity market revenues over the analysis period.

$$\max_{P_{\mathrm{el},t}} \sum_{t=1}^{T} P_{\mathrm{el},t} \cdot \Delta t \cdot p_t \qquad \text{(Eq. 2)}$$

Equation 3 limits the total electrical energy generation of the CHP plant over all hours of the year. This constraint is based on the eligible operating hours under the current regulatory framework for highly flexible biomethane CHP plants and corresponds to a rated capacity of 10 % of the installed capacity $P_{\max}$.

$$\sum_{t=1}^{T} P_{\mathrm{el},t} \cdot \Delta t \leq 0.1 \cdot P_{\max} \cdot T \cdot \Delta t \qquad \text{(Eq. 3)}$$

In addition, Equation 4 defines the feasible operating range of the electrical power output $P_{\mathrm{el},t}$ of the CHP plant. A minimum load level of 50 % of the installed capacity $P_{\max}$ is imposed. The binary variable z_t represents the operating state, where $z_t = 1$ indicates operation and $z_t = 0$ indicates shutdown.

$$0.5 \cdot P_{\max} \cdot z_t \leq P_{\mathrm{el},t} \leq P_{\max} \cdot z_t \qquad \text{(Eq. 4)}$$

The eligibility criterion for receiving the flexibility premium requires the CHP plant to generate, over the course of the year, a quantity of electricity equivalent to operating at least 85 % of the installed capacity for a minimum of 500 operating hours. To ensure compliance with the requirements and the associated eligibility for support, Equation 5 and Equation 6 are applied. The binary variable y_t identifies the hours that are relevant for this eligibility requirement, as in these hours the electrical output is at least 85 % of the installed capacity.

$$P_{\mathrm{el},t} \geq 0.85 \cdot P_{\max} \cdot y_t \qquad \text{(Eq. 5)}$$

$$\sum_{t=1}^{T} y_t \geq 500 \qquad \text{(Eq. 6)}$$

The gas volumetric flow rate $\dot{V}_{\mathrm{withdrawal},t}$ from the gas storage system in Nm^3/h is calculated based on the fuel-related energy input of the CHP plant $P_{\mathrm{fuel},t}$ and the lower heating value of natural gas (H-gas quality) $H_{\text{natural gas}}$ = *10,337* $\mathrm{kWh}_{\mathrm{LHV}}/\mathrm{m}^3$ (Cerbe and Lendt 2017). The thermal power input supplied via natural gas $P_{\mathrm{fuel},t}$, is determined by the electrical power output of the CHP plant $P_{\mathrm{el},t}$ and the electrical efficiency η_{el} (Equation 7). A scalable CHP configuration consisting of identical modules is assumed. A uniform efficiency of 45 % (based on the lower heating value) is applied across all considered CHP nominal capacities.

$$\dot{V}_{\mathrm{withdrawal},t} = \frac{P_{\mathrm{fuel},t}}{H_{\text{natural gas}}} = \frac{P_{\mathrm{el},t}}{\eta_{\mathrm{el}} \cdot H_{\text{natural gas}}} \qquad \text{(Eq. 7)}$$

The following section defines the storage content conditions that represent the operational behaviour of the gas storage system within the modelling framework. Here $\dot{V}_{\mathrm{charging},t}$ denotes the gas volumetric flow rate used to charge the gas storage system from the natural gas grid. The storage content s_t is governed by the following relationship according to Equation 8.

$$s_t = s_{t-1} + \left(\dot{V}_{\mathrm{charging},t} - \dot{V}_{\mathrm{withdrawal},t}\right) \cdot \Delta t, \qquad t = 1, \dots, T \qquad \text{(Eq. 8)}$$

The usable gas storage capacity is accounted for by the constraints given in Equation 9 and is limited by the parameter $s_{\max}$.

$$0\ \mathrm{Nm}^3 \leq s_t \leq s_{\max} \qquad \text{(Eq. 9)}$$

Equation 10 imposes an upper bound on the hourly gas withdrawal rate $\dot{V}_{\mathrm{charging},t}$, which is used to charge the gas storage system, through the parameter $\dot{V}_{\text{grid withdrawal,max}}$. This constraint ensures that the operator-defined maximum gas withdrawal rate from the natural gas grid is not exceeded, to minimise capacity-based grid charges.

$$\dot{V}_{\text{charging},t} \leq \dot{V}_{\text{grid withdrawal,max}} \quad \text{(Eq. 10)}$$

Figure 4 shows the one-week operational profile of a CHP plant with gas storage (10,000 Nm^3) and a maximum gas withdrawal rate from the natural gas grid $\dot{V}_{\text{grid withdrawal,max}}$ limited to 200 Nm^3/h. For the reference scenarios without gas storage at the gas offtake point, no additional constraint on gas withdrawal is imposed. Analogously to the calculation of the gas volumetric flow rate in the gas storage scenario Equation 7, the gas withdrawal rate is determined based on the electrical power output of the CHP plant $P_{\text{el},t}$, the lower heating value of natural gas $H_{\text{natural gas}}$, and the electrical efficiency η_{el} (based on lower heating value) (Equation 11).

$$\dot{V}_{\text{grid withdrawal},t} = \frac{P_{\text{el},t}}{\eta_{\text{el}} \cdot H_{\text{natural gas}}} \quad \text{(Eq. 11)}$$

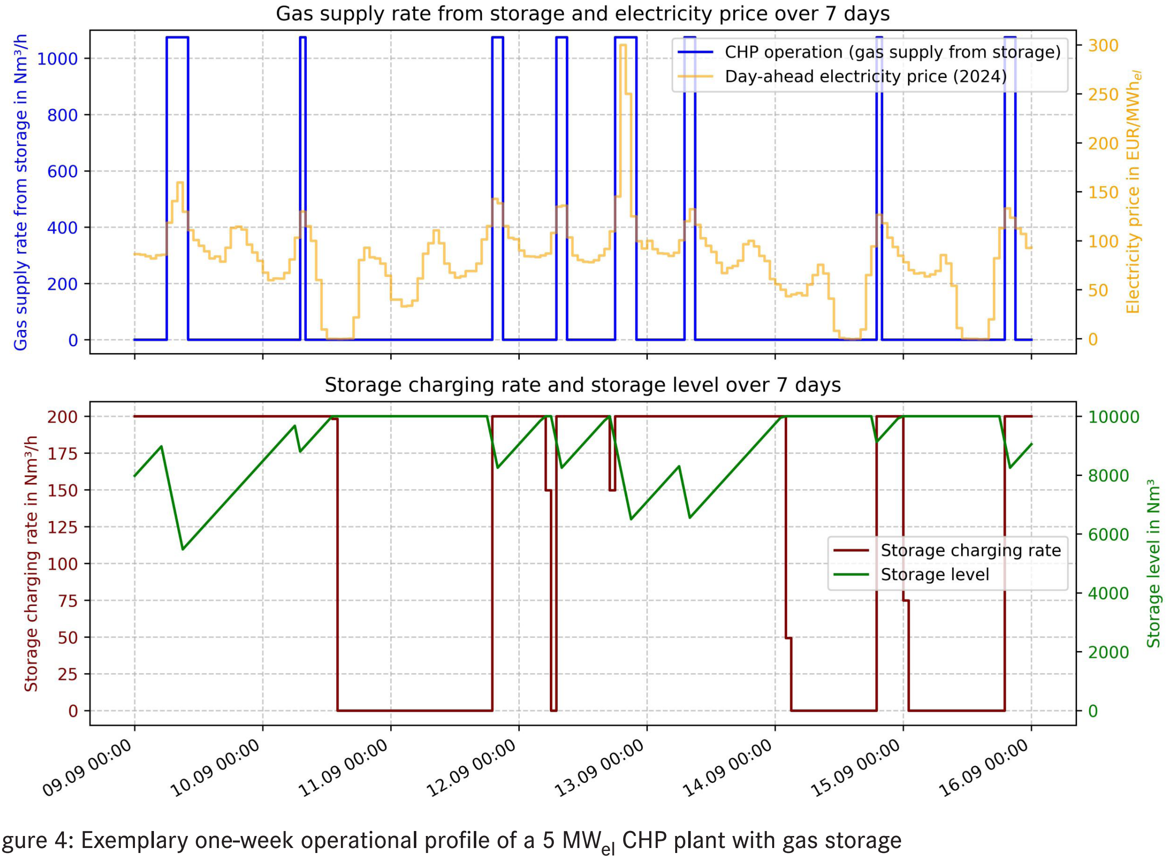


Figure 4: Exemplary one-week operational profile of a 5 MW_{el} CHP plant with gas storage

Based on the time series $\dot{V}_{\text{grid withdrawal},t}$, the maximum hourly gas withdrawal rate from the natural gas grid $\dot{V}_{\text{grid withdrawal,max}}$ is defined for the reference scenarios according to Equation 12.

$$\dot{V}_{\text{grid withdrawal,max}} = \max_{t=1,\dots,T}(\dot{V}_{\text{grid withdrawal},t}) \qquad \text{(Eq. 12)}$$

To obtain results that are robust with respect to electricity price variability, electricity price data for the years 2019 to 2024 are used in the analysis (day-ahead electricity prices provided by the Federal Network Agency, available via the SMARD platform (Bundesnetzagentur 2025). The electricity price year 2022 is excluded from the analysis due to atypical market conditions. For each year, the difference in achievable electricity market revenues between the gas storage scenarios and the corresponding reference scenario is calculated. The mean value over the considered years is included in the assessment as an annuity.

Calculation of the Natural Gas Grid-Related Costs

The charges, levies, and other cost components considered within the natural gas grid are differentiated into energy-based and capacity-usage-based components. The energy-based costs are influenced exclusively by the CHP plant size and result from the 876 annual full-load operating hours. The capacity-based costs depend on the maximum hourly gas withdrawal rate from the natural gas grid: for a direct CHP connection, this corresponds to the gas withdrawal rate under full-load operation, whereas for gas storage scenarios, the respective operator-defined maximum gas withdrawal rate is considered. Table 2 summarises most cost components relevant to the transport modalities considered in this study.

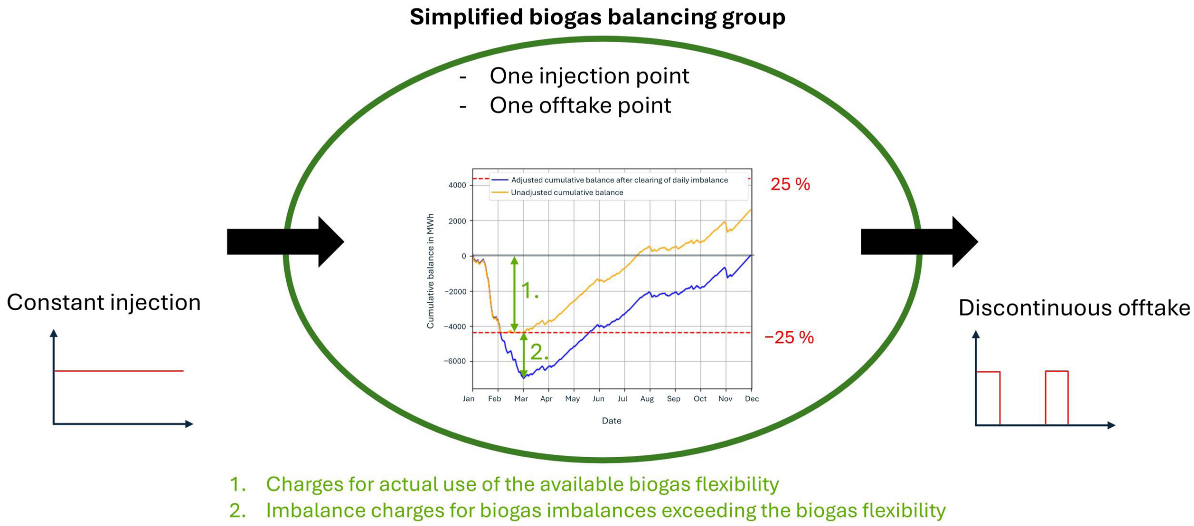
The minimum and maximum values are reported respectively and should be interpreted as the resulting cost range. The concession fee is included in the calculation at 0 ct/kWh$_{\text{HHV}}$ for all considered offtake cases in this study, deviating from the general cost range presented in Table 2, as the respective annual gas withdrawal volumes exceed the threshold of 5 million kWh$_{\text{HHV}}$ (KAV 1992). To derive the range of network usage charges, eight representative tariff structures from the year 2025 are used. These are obtained from different network operators (including municipal utilities and grid companies) and are selected to represent both urban and rural supply areas (Table A3 in the Appendix). The tariff structures differ in their composition and in the level of energy-based and capacity-based cost components. For the assessment of gas storage deployment, the capacity-based component is particularly relevant, as the potential cost savings primarily result from its reduction.

Table 2: Costs, charges, and levies for biomethane in the natural gas grid

Energy-based components	**Min. costs in ct/kWh$_{HHV}$**	**Max. costs in ct/kWh$_{HHV}$**	**Source**
Metering and Metering point operation	0	0.023	(Bundesnetzagentur 2024)
Avoided network tariffs (10-years)	-0.7	-0.7	(Adler et al. 2014)
Gas storage neutrality charge	0.299	0.299	(Trading Hub Europe 2024)
Conversion fee and neutrality charge	0	0	(Trading Hub Europe 2024)
RLM balancing neutrality charge	0	0	(Trading Hub Europe 2024)
Concession fee	0	0.03	(KAV 1992)
Accounting and certification	0.3	0.9	(T. Reinholz, e-mail communication on the costs of biomethane verification, 24 Jan 2025)
Biomethane trading costs	0.1	1.0	(C. Löffler, personal communication on natural gas grid charges, levies and flexibility range for the settlement of biogas balancing groups, 17 Feb 2025)
VTP-fee	0.000198	0.000198	(Trading Hub Europe 2024)

Capacity-based components	**Min. costs in ct/(kWh$_{HHV}$/h)/a**	**Max. costs in ct/(kWh$_{HHV}$/h)/a**	**Source**
Biogas neutrality charge	105.42	105.42	(Trading Hub Europe 2024)
Market area conversion charge	67.13	67.13	(Trading Hub Europe 2024)

In addition to the VTP fee, the remaining charges associated with biogas balancing groups are considered in a separate analysis. For the lower limit of these charges, a value of 0 ct/kWh$_{HHV}$ is assumed, implying that any deviations within the balancing group are fully offset by the balancing group manager's portfolio and do not result in any additional costs. The upper limit of these charges is determined using a simplified balancing group model that reflects the continuous injection of biomethane and the discontinuous offtake of a highly flexible CHP plant (illustrated schematically in Figure 5).



1. Charges for actual use of the available biogas flexibility
2. Imbalance charges for biogas imbalances exceeding the biogas flexibility

Figure 5: Model of the simplified biogas balancing group with one injection point featuring a temporally constant injection profile and one offtake point with a discontinuous offtake profile

For each scenario considered, the corresponding gas grid offtake profile from the dispatch optimisation is used for this purpose. The following assumptions apply to the modelling:

- No storage capacities are booked by the balancing group manager; exceedances of the flexibility range are balanced exclusively with positive or negative imbalance quantities.
- A one-year balancing period with determination of balancing group status on a daily basis in accordance with the principles of biogas balancing group settlement (Bundesverband der Energie- und Wasserwirtschaft e.V. 2017)
- For comparability purposes, positive closing energy balances are financially settled at the arithmetic mean of the applicable positive imbalance price; no carry-over to a subsequent balancing period is considered
- Historical imbalance prices published by Trading Hub Europe (2024, 2025) and linked to electricity prices are used to represent typical market conditions

Financial Assumptions

The annuity calculation is based on an interest rate of 5 % and assumed annual price escalation rates of 2 %. Deviating escalation rates of 4 % and 3.4 % are applied for electricity costs and for the gas pressure regulating station and electrical installations, respectively. To ensure comparability, the nominal specific energy supply costs are converted into real costs adjusted for inflation. For this purpose, a correction factor is derived from the ratio of the present cash values with and without the general annual price increase of 2 % (≈ 0.85), while component-specific price deviations are retained.

Results

The total specific biomethane supply costs, considering the entire process chain – from biogas production to the CHP plant directly connected to the natural gas grid – are shown in Figure 6. The specific biogas production costs are included as a parameter ranging from 5.0 to 8.0 ct/kWh$_{HHV}$. The average values of the cost ranges amount to between 9.82 and 13.26 ct/kWh$_{HHV}$. The cost ranges are determined by linear aggregation of the respective cost ranges of the individual process chain sections. The results are presented for the three CHP plant sizes of 5 MW$_{el}$, 10 MW$_{el}$ and 20 MW$_{el}$ and their corresponding gas withdrawal capacity.

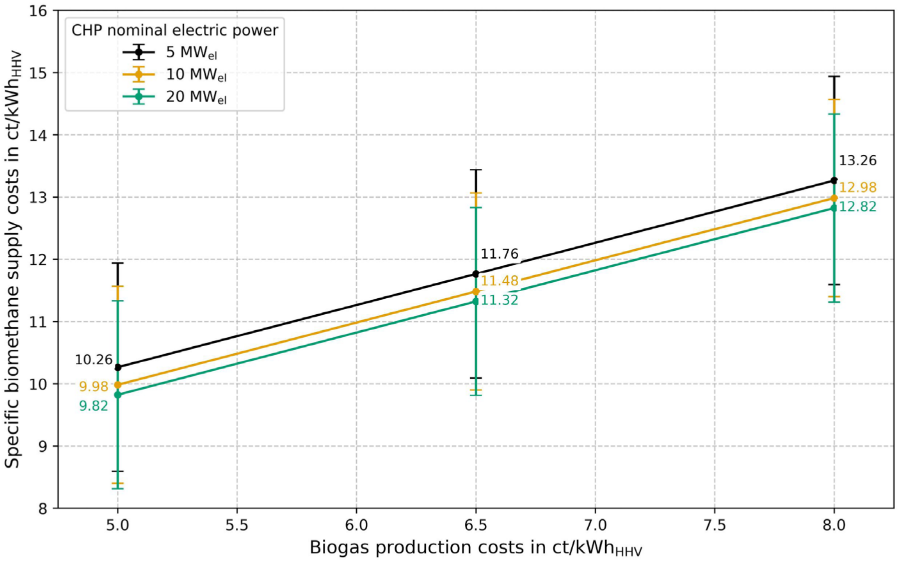


Figure 6: Specific biomethane supply costs depending on biogas production costs and gas withdrawal capacity for three different CHP plant rated outputs

The breakdown of biomethane supply costs for CHP units with rated outputs of 5, 10 and 20 MW_{el} is shown in Figure 7. In this analysis, biogas production costs are assumed to be 6.5 ct/kWh_{HHV} and represent the largest cost component. The second-largest share of costs relates to the natural gas grid, at between 1.59 and 4.92 ct/kWh_{HHV}, followed by the costs of biogas upgrading, amounting to 1.63 ct/kWh_{HHV}. The costs for the grid connection at the feed-in point (0.03 to 0.32 ct/kWh_{HHV}) have a minor impact on the total costs compared to the other components. A slight economy-of-scale effect in the specific biomethane supply costs can be observed across the CHP plant sizes considered.

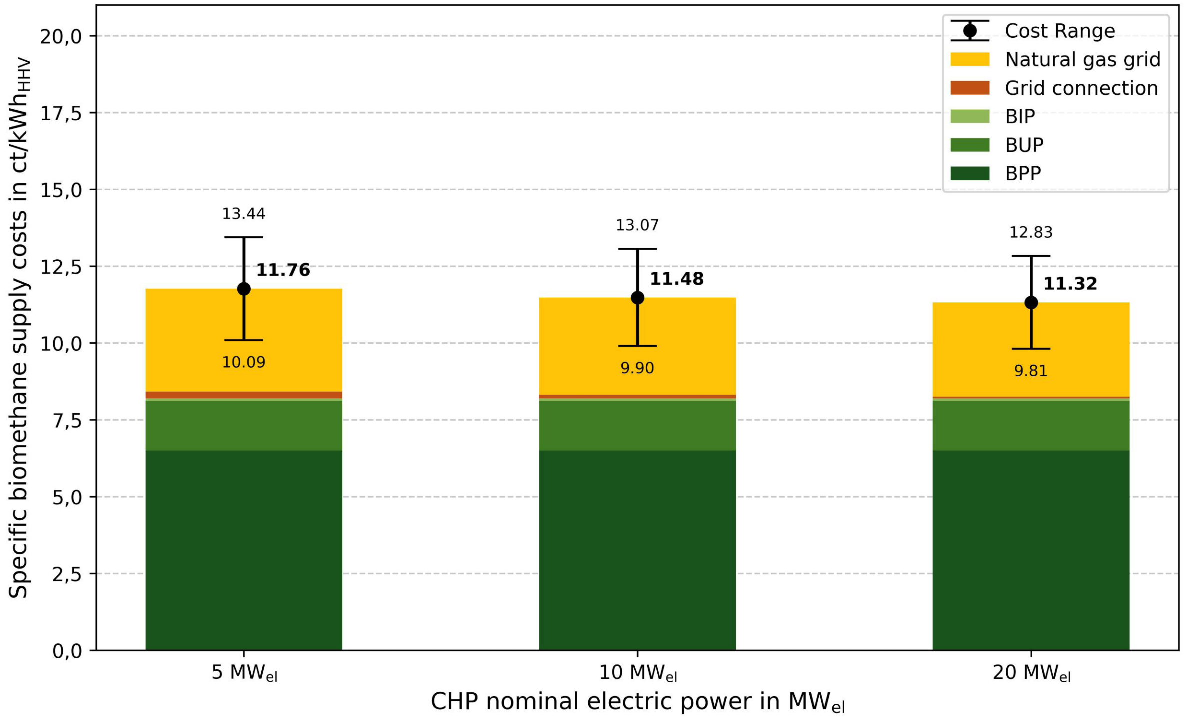


Figure 7: Composition of specific total biomethane supply costs depending on gas withdrawal capacity for three different CHP plant rated outputs

Figure 8 shows the natural gas grid costs for minimum and maximum assumptions, broken down into capacity-based and energy-based costs as well as costs related to the biogas balancing charges. Capacity-based costs represent the dominant cost component, while energy-based costs also contribute significantly. Both costs exhibit a wide range of values. By contrast, the costs related to the biogas balancing charges remain comparatively small, amounting to approximately 0.16 ct/kWh_{HHV} even under the modelled maximum assumptions. The presented results are based on the consideration of avoided network tariffs over a period of ten years. If these are fully excluded, natural gas grid costs increase by up to 0.37 ct/kWh_{HHV}, resulting in correspondingly higher total biomethane supply costs.

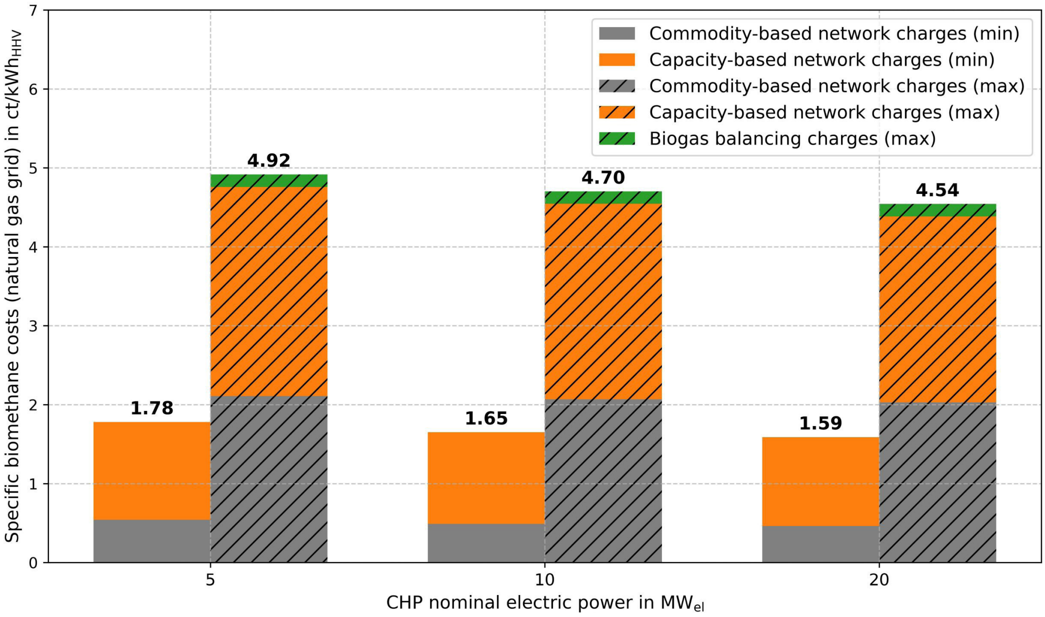


Figure 8: Specific costs associated with the natural gas grid depending on the gas withdrawal rate for three different CHP nominal capacities (minimum and maximum values), differentiated into demand-related and commodity-related costs as well as costs resulting from the biogas balancing charges.

To address the second research question, the effects of gas storage deployment on biomethane supply costs are analysed, using mean values of the energy-based cost ranges (grid connection and natural gas grid costs) as a basis. Biogas balancing charges are initially excluded from the results for reasons of simplification. Capacity-based network charges are considered in detail, as they have a significant influence on the cost efficiency of gas storage systems. For illustrative purposes, results are presented for cases with the highest and lowest capacity-based network usage charges, as the remaining tariff structures fall within this range.

Figure 9 shows the difference in biomethane supply costs in ct/kWh$_{\mathrm{HHV}}$ for the analysed gas storage scenarios compared to the reference case without gas storage (blue area). These differences are presented for the 5 MW$_{\mathrm{el}}$ CHP plant under scenarios with the highest capacity-based network usage charges. For the reference case, these specific costs amount to 21.5 €/(kW$_{\mathrm{th}}$ · a) (based on higher heating value) at a full-load gas withdrawal rate of 1,075 Nm^3/h. For reduced maximum gas withdrawal rates, higher specific costs arise under the applied tariff structure. For cost components defined by value ranges, such as the physical grid connection and natural gas grid costs (excluding network usage charges), mean values are applied. The results show that, at lower maximum gas withdrawal rates, larger storage capacities become cost-effective, and no universally optimal storage capacity exists. The lowest supply costs are achieved with a gas storage capacity of 12,000 Nm^3 and a maximum gas withdrawal rate of 200 Nm^3/h (corresponding to approximately 19 % of the full-load gas withdrawal rate of the CHP plant at 1,075 Nm^3/h). In this case, costs amount to -1.68 ct/kWh$_{\mathrm{HHV}}$, which is significantly below the reference value.

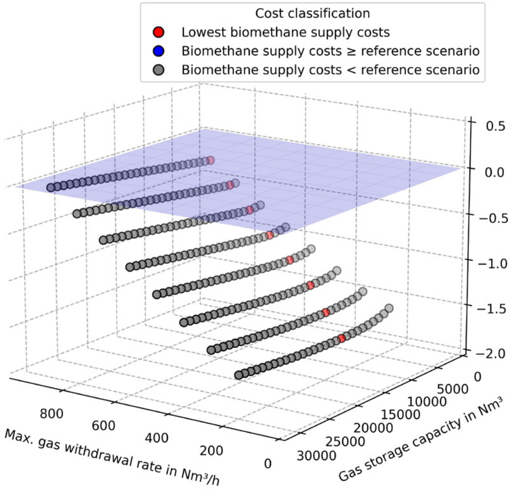


Figure 9: Biomethane supply costs for different gas storage capacities and different gas withdrawal rates, compared to the reference case without gas storage (blue reference area); example case: 5 MW_{el} CHP plant with high capacity-based network usage charges of 21.5 €/(kWth · a) (based on higher heating value)

Figure 10 shows the difference in biomethane supply costs, presented analogously to Figure 9, assuming network usage charges with the lowest capacity-based costs of 9.1 €/(kWth · a) (based on higher heating value) for full-load gas withdrawal. Here as well, the gas storage system reduces supply costs compared to the reference case. The most cost-efficient scenario likewise features a gas storage capacity of 12,000 Nm^3 and a maximum gas withdrawal rate of 200 Nm^3/h, achieving a cost reduction of 0.49 ct/kWh_{HHV}. In contrast of the case with high capacity-based network usage charges, no cost advantages over the reference case without gas storage are observed at high gas storage capacities and high maximum gas withdrawal rates.

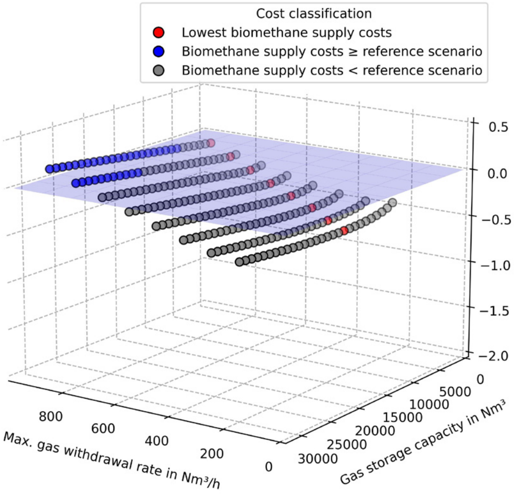


Figure 10: Biomethane supply costs for different gas storage capacities and different gas withdrawal rates, compared to the reference case without gas storage (blue reference area); example case: 5 MW_{el} CHP plant with low capacity-based network usage charges of 9.1 €/(kWth · a) (based on higher heating value)

Table 3 summarises the most cost-efficient scenarios with gas storage deployment for the considered CHP plants with installed electrical capacities of 5 MW_{el}, 10 MW_{el} and 20 MW_{el}. In addition, the magnitude by which biomethane supply costs can be reduced compared to the respective reference case is presented. The results are shown according to network usage charges with the lowest (min.) and highest (max.) capacity-based costs. It should be noted that the considered range of gas storage capacities extends up to a maximum value of 30,000 Nm^3, and that larger storage capacities may potentially lead to lower supply costs for the CHP plant with an installed capacity of 20 MW_{el}.

Table 3: Maximum reduction in supply costs through gas storage deployment with a cost-optimal combination of gas storage capacity and maximum gas withdrawal rate across the considered CHP plant sizes of 5, 10 and 20 MW_{el}

CHP nominal electric power	**5 MW_{el}**		**10 MW_{el}**		**20 MW_{el}**	
Capacity-based network usage charges	Min.	Max.	Min.	Max.	Min.	Max.
Gas storage capacity in Nm^3	12,000	12,000	24,000	24,000	30,000	30,000
Maximal gas withdrawal rate in Nm^3/h	200	200	400	400	800	800
Cost reduction (in biomethane supply costs) in ct/kWh_{HHV}	0.49	1.68	0.50	1.59	0.45	1.51

The results for the 10 MW_{el} and 20 MW_{el} cases show, under scaled maximum gas withdrawal rates and gas storage capacities (factors of 2 and 4, respectively), a system behaviour that is largely analogous to that of the 5 MW_{el} CHP plant. The location of the cost-optimal points in the parameter space defined by gas storage capacity and maximum gas withdrawal rate remains unchanged right up to the limits of the range of values under consideration (see Figure A1 in the Appendix).

The following section analyses the breakdown of biomethane supply costs for scenarios involving gas storage. This is carried out exemplarily for the CHP plant with an installed electrical capacity of 5 MW_{el}. Figure 11 shows the cost structure for network usage charges with the highest capacity-based costs, while Figure 12 presents the corresponding composition considering the lowest capacity-based costs. The analysis is limited to the scenario conditions that result in the lowest biomethane supply costs (cf. the scenarios marked in red in Figure 9 and Figure 10).

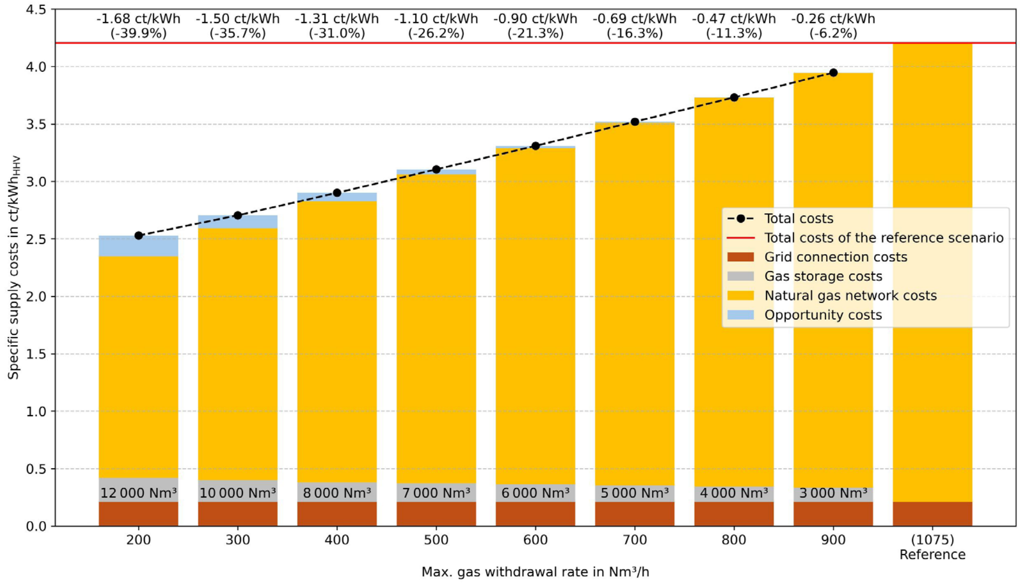


Figure 11: Composition of supply costs as a function of maximum gas withdrawal rate and the corresponding cost-minimising gas storage size; example case: 5 MW_{el} CHP plant with high capacity-based network usage charges of 21.5 €/(kW_{th} · a) (based on higher heating value)

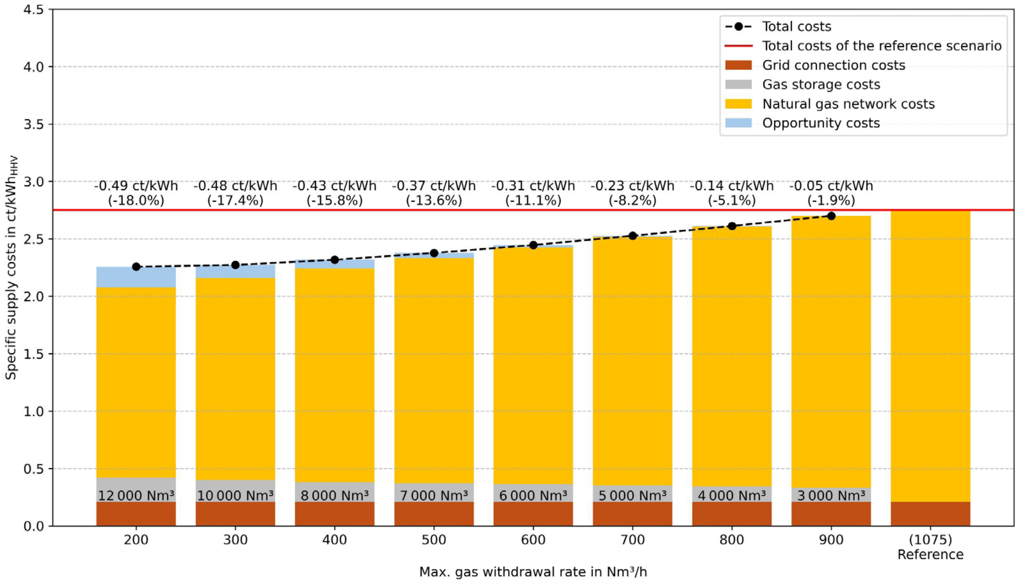


Figure 12: Composition of supply costs as a function of maximum gas withdrawal rate and the corresponding cost-minimising gas storage size; example case: 5 MW_{el} CHP plant with low capacity-based network usage charges of 9.1 €/(kW_{th} · a) (based on higher heating value)

Different maximum gas withdrawal rates lead to different cost-optimal gas storage capacities and consequently, to varying shares of gas storage costs. The analysis in both figures focuses on the respective cost-efficient storage capacities for each gas withdrawal rate. The reference case without gas storage serves as the benchmark (shown on the right-hand side for comparison). Overall, the share of opportunity costs is low; however, it increases disproportionately as the maximum gas withdrawal rate decreases. Gas storage costs also contribute only marginally to total costs. At lower withdrawal rates, larger storage capacities become more cost-efficient. In this context, lower opportunity costs compensate for the additional storage costs. The comparison of the results in Figure 11 and Figure 12 shows that gas storage deployment can also contribute to a reduction in natural gas grid costs under network usage charges with low capacity-based cost components, albeit to a lesser extent.

Figure 13 presents the modelled maximum biogas balancing charges, expressed in ct/kWh$_{HHV}$, for the previously filtered selection of cost-optimal scenarios for which the cost structure is analysed. Results are additionally shown for CHP plants with installed electrical capacities of 10 MW$_{el}$ and 20 MW$_{el}$. Compared to the reference cases, limiting the maximum gas withdrawal rate leads to lower biogas balancing charges. For the reference cases, these amount to approximately 0.16 ct/kWh$_{HHV}$. With decreasing relative maximum gas withdrawal rate compared to the reference case, biogas balancing charges decrease accordingly. With respect to the relative maximum gas withdrawal rate, the energy-based balancing charges show identical values in ct/kWh$_{HHV}$ across all considered CHP plants.

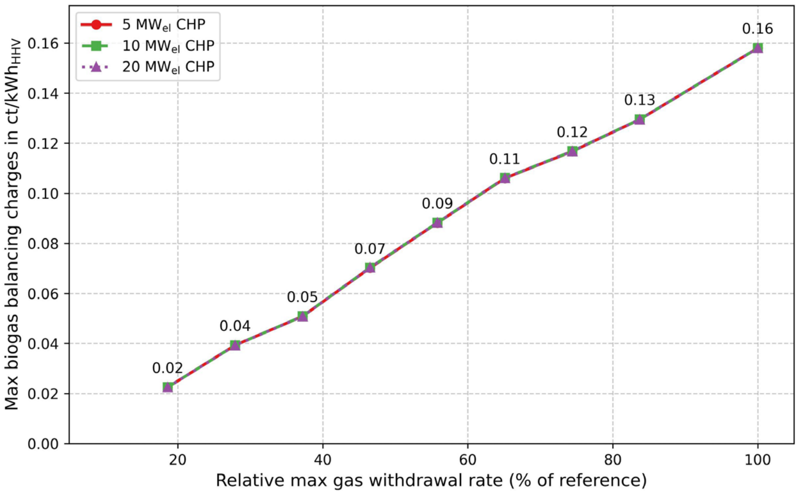


Figure 13: Biogas balancing charges in relation to maximal gas withdrawal rate, expressed as a relative share of the full-load gas withdrawal rate of the respective CHP plant without gas storage

Figure 14 shows the average achievable electricity revenues for different gas storage capacities and maximum gas withdrawal rates, relative to the reference case without gas storage and without operational constraints. With increasing storage capacity and higher maximum gas withdrawal rates, electricity revenues increase, whereas smaller storage capacities and stricter limitations on the maximum gas withdrawal rate lead to reduced revenues and correspondingly higher opportunity costs. In the scenario with the smallest storage capacity and the lowest maximum gas withdrawal rate, only 92 % of the average electricity revenues of the reference case without gas storage can be achieved. Consequently, this scenario exhibits the highest opportunity costs.

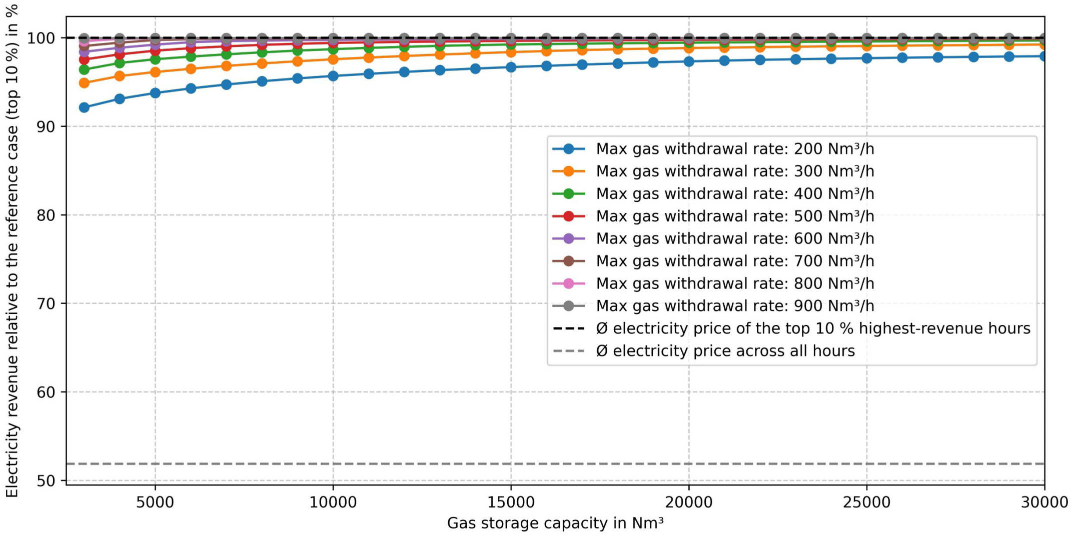


Figure 14: Reduced revenues in the electricity market due to operational flexibility constraints of the CHP plant

Discussion

The calculated biomethane supply costs are based on an annuity calculation in accordance with VDI 2067 (Verein Deutscher Ingenieure 2012) and range from 9.81 to 13.44 ct/kWh$_{HHV}$. The average year-ahead price for biomethane produced from renewable feedstocks for electricity and heat generation under the EEG amounted to 10.82 ct/kWh$_{HHV}$ over the period from 2023 to 2024 (agriportance GmbH 2025). A comparison shows that some of the modelled biomethane supply costs exceed this price level. Although market prices cannot be equated directly with supply costs, as they are also influenced by supply and demand structures and market conditions, this comparison provides an initial assessment of the economic situation. Against this backdrop, there are indications that securing financing for biomethane supply may prove economically challenging under the current conditions.

The low level of participation in biomethane auctions could be attributed, among other things, to this factor. A breakdown of the total biomethane supply costs shows that biogas production costs account for the largest share of the costs. These are followed by costs related to the natural gas grid, followed by expenses for biogas upgrading, grid connection costs, and biomethane injection. The innovative aspect of this study lies in the integration of a holistic process chain analysis with a detailed assessment of gas storage deployment at the gas offtake point. This approach not only enhances transparency regarding the cost structure of biomethane supply, but also systematically demonstrates, for the first time, under which framework conditions gas storage can contribute to reducing these supply costs. The results should be interpreted in consideration of potential uncertainties.

The annuity method is sensitive to assumed inflation rates and underlying cost components, some of which have been updated based on general price escalation rates. The capacity-based components of natural gas grid costs are primarily determined by the applicable network usage charges. The range of network usage charges is determined based on eight different tariff structures, which were specifically selected to include both rural and urban distribution system operators. In practice, however, it can be assumed that additional tariff structures exist, whose characteristics may lie above or below the considered ranges both in absolute terms and with respect to their energy- and capacity-based charge levels. The available network usage charges as well as biomethane trading and certification costs, exhibit a wide range, resulting in a substantial overall cost spread for natural gas grid-related costs. Consequently, the economic conditions may vary significantly in practice.

The deployment of a gas storage system at the gas offtake point can contribute to a pronounced reduction in total biomethane supply costs across all analysed CHP capacities. The largest cost-saving potentials occur under particularly favourable conditions, such as location-specific network usage charges with high capacity-based charge levels. Under these conditions, the precise sizing of the gas storage capacity plays only a subordinate role, whereas the maximum gas withdrawal rate from the natural gas grid has a decisive influence on the supply costs. This is reflected in significantly varying supply costs across the range of maximum gas withdrawal rates. Against this background, targeted limitation of the maximum gas withdrawal rate proves to be a key lever for cost reduction. Even under network usage charges with low capacity-based charge levels, the deployment of a gas storage system can reduce supply costs, albeit to a lesser extent. The costs associated with the settlement of biogas balancing groups remain at a low level for cost-optimal combinations of maximum gas withdrawal rate and gas storage capacity. Under the investigated framework conditions, the deployment of a gas storage system contributes to a reduction in these balancing charges.

For the CHP plant with an installed electrical capacity of 20 MW_{el}, the cost-optimal gas storage capacity reaches the upper limit of the considered model range of 30,000 Nm^3. Larger storage capacities are not considered within the investigated range due to their presumed limited practical feasibility, for example because of the required land area. If technically feasible, larger storage systems could, under suitable framework conditions, potentially lead to a further reduction in total supply costs in this case. A practical example of the implementation of such a gas storage system at the gas offtake point of the natural gas grid can be found at the Thiendorf site. At this site, Danpower GmbH operates a CHP plant with an installed capacity of 19.8 MW_{el} and a double membrane gas storage system with a usable volume of approximately 13,000 Nm^3. A larger storage capacity could not be implemented due to spatial constraints, although it was considered economically viable by the operator. This highlights that the transferability of the results to real-world applications requires consideration of site-specific constraints on storage dimensioning.

The presented cost-saving potentials and the general transferability of the results are valid within the modelling assumptions and parameter boundaries defined in this study. Likewise, the analysis is based on a limited set of eight network usage tariff structures, which, while covering a broad range, do not capture all tariff configurations that exist in practice. Alternative structures with higher or lower energy- and capacity-based charge levels are generally possible and may lead to different economic results. In addition, the scenarios are based on discretely selected parameter combinations for gas storage and maximum gas withdrawal rate. Consequently, the identified cost-optimal configurations should be interpreted as approximations. The operational simulations of the CHP plants used to derive the opportunity costs were conducted ex post and are therefore based on the idealised assumption of perfect foresight regarding electricity price developments over the considered period. Based on this, maximum theoretical electricity revenues are determined for both the gas storage scenarios and the reference scenario. The difference between these revenues is used to quantify the opportunity costs.

In practical applications, however, imperfect price forecasting must be assumed. As a result, the achievable revenues, and consequently the resulting opportunity costs, may deviate from the values reported in this study. Furthermore, the electricity price has a significant influence on the opportunity costs: both the absolute price level and the temporal price profile are decisive for their magnitude.

A single-year analysis for the electricity year 2022 (Idda et al. 2025) shows that opportunity costs can be significantly higher under extreme price conditions. Beyond electricity price dynamics, additional system factors such as heat sink integration or alternative plant configurations may affect optimal dispatch scheduling. These aspects provide relevant avenues for future research.

In addition to its economic implications, the gas storage system can also enhance the technical feasibility of larger CHP plants at locations with limited gas transport capacity in the distribution grid. Low network pressure levels or long connection pipelines with associated pressure losses may restrict the available gas withdrawal capacity required for the operation of larger CHP units. The temporal decoupling between gas withdrawal from the grid and plant operation enabled by intermediate gas storage allows these constraints to be mitigated and higher electrical capacities to be realised. In this way, sites that would be technically infeasible or only partially usable for CHP deployment may become accessible through the integration of gas storage systems.

Conclusions

This study shows that the modelled total biomethane supply costs, ranging from 9.81 to 13.44 ct/kWh$_{HHV}$, are in part above current market price levels, indicating that under the considered framework conditions economic challenges may arise for economically viable operation. The cost structure is primarily driven by biogas production costs. In descending order of relevance to total supply costs, the cost components associated with the natural gas grid, biogas upgrading, the gas offtake-side grid connection, and biomethane injection follow. Transportation-related modalities, including network usage charges, biomethane trading, and certification requirements, can significantly influence the cost structure and exhibit substantial variability. This applies to both capacity-based and energy-based components of natural gas grid costs.

The deployment of a double-membrane gas storage system at the gas offtake point is an effective measure for reducing biomethane supply costs. Depending on the applicable network usage tariff structure, these costs can be reduced by up to 1.68 ct/kWh$_{HHV}$, while cost savings are also achievable under less favourable tariff conditions. The results indicate that a significant limitation of the maximum gas withdrawal rate is cost-efficient. Furthermore, the cost-optimal gas storage capacities and maximum withdrawal rates scale proportionally with the installed electrical capacity of the CHP plant. Charges for biogas balancing have only a minor influence on total supply costs, irrespective of gas storage deployment. Building on the present results, future research should focus on more detailed analyses of gas storage systems and CHP plants at sites with available heat sinks and relevant heat demand. The heat sector was deliberately excluded from this study, as the design and utilization of heat applications are highly site- and application-specific and are currently subject to ongoing research. Since heat integration can have a significant impact on both the economic performance and the optimal operation of biomethane-fired CHP plants, a modified operational and revenue framework can be expected when suitable heat utilisation is considered. In such cases, CHP operation is no longer driven solely by electricity prices, and different optimal dispatch strategies are likely to emerge.

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Acknowledgments

The research project BioM0876 (grant number: 2221NR085A), from which this contribution originates, is funded by the German Federal Ministry of Agriculture, Food and Regional Identity (BMELH) based on a resolution of the German Bundestag. The project is administrated by the Fachagentur für Nachwachsende Rohstoffe (FNR).