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Optimization-based investigation of different repurposing concepts for Austrian coal-fired power plants

Thomas Kienberger · Anna Traupmann · Roberta Cvetkovska

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Abstract Even though the current war in Ukraine has led to a short-time renaissance of coal-fired power plants, the age of coal-based power generation is about to end. Nevertheless, the coal-fired power plants no longer needed for their original purpose are still valuable assets. In this paper, we consider three technological approaches for repurposing them: gas-to-power (operation of combined cycle gas turbine plants), power-to-gas (operation of electrolysis plants for feeding hydrogen into the gas grid), and a combination of the two technologies mentioned above. Our aim is to find optimal operating modes in terms of profit for the three approaches. For this, we use a mixed-integer linear multi-variable optimization model and time-resolved price forecasts for electricity and gas for 2030 and 2040. Our results show that, also in future energy systems, gas-to-power plants allow for economic benefits: In times of district heat demand, they operate in the spot market and profit from dual revenues. Balance and ancillary markets allow for additional revenues from the capacity provision. Power-to-gas plants do not show the same good economic performance. However, they allow for an economically sound operation and gain most of their profits in the spot market. Compared to the others, combined plants do not offer economic advantages. In our paper, we also investigate the currently high energy price situation. It allows for payback periods of power-to-gas plants as anticipated for 2040. For this reason, long-term high prices may accelerate the deployment of such future technologies.

T. Kienberger ist OVE-Mitglied.

T. Kienberger (✉) · A. Traupmann · R. Cvetkovska
Chair of Energy Network Technology, Montanuniversitaet Leoben, Franz-Josef-Straße 18, 8700 Leoben, Austria
thomas.kienberger@unileoben.ac.at

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Optimierungsbasierte Betrachtung unterschiedlicher Nachnutzungskonzepte österreichischer Kohlekraftwerksstandorte

Zusammenfassung Kohlekraftwerksstandorte, die für ihren ursprünglichen Zweck nicht mehr benötigt werden, sind nach wie vor wertvolle Assets. In dieser Arbeit betrachten wir drei technologische Ansätze für deren Nachnutzung: Gas-to-Power (Betrieb von Gas- und Dampfturbinenkraftwerken), Power-to-Gas (Betrieb von Elektrolyseanlagen zur Einspeisung von Wasserstoff in das Gasnetz) und eine Kombination der beiden oben genannten Technologien. Unser Ziel ist es, gewinnoptimierte Betriebsweisen für die drei Ansätze zu finden. Dazu verwenden wir ein gemischt-ganzzahliges lineares Mehrvariablen-Optimierungsmodell und zeitaufgelöste Preisprognosen für Strom und Gas für die Jahre 2030 und 2040. Unsere Ergebnisse zeigen, dass klassische Gas-to-Power-Anlagen auch in zukünftigen Energiesystemen wirtschaftliche Vorteile ermöglichen: In Zeiten mit Fernwärmebedarf werden sie auf dem Spotmarkt eingesetzt und profitieren von doppelten Erlösen. Märkte für Systemdienstleistungen ermöglichen zusätzliche Erlöse aus der Kapazitätsbereitstellung. Power-to-Gas-Anlagen weisen keine vergleichbare Performance auf. Sie ermöglichen dennoch einen wirtschaftlich soliden Betrieb und erzielen den größten Teil ihrer Gewinne ebenfalls auf dem Spotmarkt. Im Vergleich dazu bieten Kombinationsanlagen keine wirtschaftlichen Vorteile. In unserer Arbeit untersuchen wir zusätzlich den Einfluss der derzeitig hohen Energiepreise auf den Einsatz bzw. die Realisierung der genannten Technologien. Die aktuelle Preissituation ermöglicht

Amortisationszeiten von Power-to-Gas-Anlagen, wie sie erst für 2040 erwartet wurden. Daher könnten langfristig hohe Preise den Einsatz solcher Zukunftstechnologien maßgeblich beschleunigen.

Schlüsselwörter Nachnutzung von Kohlekraftwerken · Betriebsoptimierung · Power-to-Gas · Gas- und Dampf-Kombikraftwerke · Sektorkopplung

1 Introduction

Although the current energy crisis brings already closed coal-fired power plants back to the grid [1], the age of coal-based power generation gets close to its end. According to plans of the EU-member states, 72% of the currently operated coal-fired power plants are about to be closed by 2025 [2, 3].

However, the coal-fired power plant sites, now no longer needed for their original purpose, are still valuable assets. In particular, their access to high-level electricity, gas, and heat grids and their strong supply- and disposal infrastructure is still very relevant, not least concerning the energy transition goals. In the EU-RFCS project RECPP—Re-purposing Coal Power Plants [4], different technological re-purposing concepts are being investigated at the European level. Besides aspects of a fuel change towards biomass, which is the most common retrofitting measure for re-using coal-fired power plants [5], some re-purposing strategies exist based on technologies such as battery-storage systems [6] or thermal energy storages [7]. Others only re-use the areas of the former coal-fired plants for non-energy-related purposes such as for warehouses, logistic-centres, etc. [8].

In this paper, based on the actual work of Traupmann et al. [9], we consider three technological approaches that show intersectoral interaction between the gas- and the electricity grid, which allows for particularly good use of the existing infrastructure assets:

1. Gas-to-Power (GtP): conventional operation of a combined-cycle gas turbine (CCGT) plant.
2. Power-to-Gas (PtG): operation of electrolysis-based plant. Injection of hydrogen into the existing gas grid—without considering blending limits.
3. combination of the two technologies mentioned above in a plant allowing for both GtP and PtG operation (GtP-PtG)

We investigate them using the coal-fired power plant site at Mellach, Austria.

1.1 State of research

CCGT power plants are, among others, pillars of the European power supply system. For an operation with natural gas as fuel, they are state-of-the-art technology. Recent research activities focus on the switch to a gas turbine operation on hydrogen containing fuel gas or pure hydrogen [10, 11]. The main issues are the control of NOx emissions without losing too much efficiency. However, major gas turbine suppliers such as Siemens Energy [12], GE [13], and Mitsubishi Power [14] have already committed to or plan large-scale tests on pure hydrogen. To support the technical development with economic investigations, Öberg et al., for instance, examined the competitiveness of hydrogen-fuelled gas turbines in future energy systems [15].

On the other hand, Power-to-Gas via RES-powered electrolysis is considered one of the technologies with high future impact. Progress on the technology side and the side of system implementation is tremendous. Newest developments of proton exchange membrane (PEM)- and alkaline water electrolyzers (AWE), for instance, reach efficiency factors of up to 82%. Solid oxide electrolyzers (SOE) reach up to 92% [16]. While the latter are only deployed on a pilot scale [17], PEM and AWE systems are about to reach industrial standards: The record breaker AWE plant with a hydrogen capacity of 260 MW is currently under construction by Chinese Oil- and Gas multi Sinopec [18]. The largest PEM plant with 20 MW hydrogen production stands in Canada [19]. To foster the way to GW installations recently published research also deal with economic investigations. Glenk et al. [20] or Loisel et al. [21] investigate economy of scale for Power-to-Gas plants to determine cost-down curves. To take into account volatile electricity prices, many approaches for design- and operation optimization exist for systems with and without storage [22]. Korpas et al. optimize the Power-to-Gas plant's operation on day-ahead markets by using generation forecasts and receding horizons [23].

Promising technology for combining both power- and hydrogen production are reversible fuel cell systems. Both PEM- and SOC-based systems are investigated in this regard. The latter gain thermodynamic advantages [24]. However, recent developments from the German supplier Sunfire [25] or Austria's AVL [26] are still in the piloting phase.

1.2 Research questions and structure of the work

Although both technological as well as implementation- and operation-related aspects of the three investigated intersectoral technologies (GtP, PtG and GtP-PtG) are intensively studied, their application as re-purposing options for coal-fired power plant sites is barely addressed. The particularities of coal-fired power plant sites as high connection-capacities to power- and gas grids, often together with heat-delivery obligations, allow for new business models for each of the three investigated technologies. With this regard, the following research questions remain open:

- What is the most optimal operational strategy to simultaneously deploy the investigated technologies

on both spot- as well as balancing and ancillary services markets?
- How will
  - future price developments (for 2030 and 2040) on all of the considered markets,
  - boundary conditions as heat-delivery revenues or
  - decreased equipment costs in the future,

  influence the optimal plant operation and the investment payback period?
- How are extreme price situations as they are now (mid-2022) affecting investment decisions on the investigated technologies?

To answer those questions, we have structured our paper as follows: In Sect. 2, we firstly describe the applied methodology for modeling both future prices in gas- and electricity markets and the multi-variable optimization of the investigated plant concepts. Secondly, Sect. 3 deals with the case study under investigation: After introducing the problem at hand (implementation constraints at the Mellach site), we present and discuss optimized operation profiles for all concepts as well as economic results as investment costs or results from return on investment calculations. In Sect. 4, finally, we conclude our work.

2 Methodology

2.1 Electricity- and gas price models

In this work we model firstly day-ahead spot market prices for both electricity and natural gas. The subsequently modeled balancing- and ancillary services markets affect only electricity and include Frequency Containment Reserve (FCR) and positive as well as negative automatic and manual Frequency Restoration Reserve (refered to as a/mFRR). We model all prices for 2030 and 2040, taking into account baseline data for the year 2020.

In order to depict the "Pay-as-cleared" electricity day-ahead spot market, we used historical data from the EXAA power exchange for the base year 2020 [27]. For modeling the years 2030 and 2040, we apply an approach based on literature data. It considers both the development of the mean annual price [28] and the number of prices higher than 100€/MWh and lower than 0€/MWh [29], which increase due to higher shares of volatile RES in the electricity mix. By means of Piecewise Cubic Hermite Interpolating Polynomial (PCHIP) fitting, we adapt the 2020 time series to match the 2030 and 2040 conditions in terms of both the mean value and the number of price event higher than 100€/MWh and lower than 0€/MWh. The latter reflects the changes in the time series of power generation due to RES (Fig. 1).

For modeling "pay-as-cleared" gas prices, we followed a similar approach. Again, we took the historical natural gas day-ahead spot market prices from the EEX [30]. The future gas mixtures and the future prices for Bio-CH_4 and hydrogen we obtained from the work of Cvetkovska et al. [31], who studied the price development of renewable gases using an extensive literature survey. Together with CO_2-price prognoses' from the Federal Environment Agency of Austria [32], we calculated total prices for the respective gas mixtures and scaled them with the time-resolved 2020 natural gas price profile (Fig. 2).

The considered balancing- and ancillary services, the Frequency Containment Reserve and the automatic as well as manual Frequency Restoration Reserve use different schemes for remuneration each. For the automatic and manual Frequency Restoration Reserve (aFRR and mFRR), two separate markets for the capacity provision and -activation are in place. Both markets apply the "pay-as-bid" principle. A merit order ranks all incoming bids for each time slot. The total required (positive or negative) a/mFRR capacity settles, which of the capacity-offers are "in the market". The activation market works similarly: for each time slot with a demand for control power the cheapest activation offers are chosen.

In contrast, remuneration of Frequency Containment Reserve (FCR) happens on a one "pay-as-bid" market, which refunds capacity provision and possible activation in a single step. The bids on the FCR market always consists out of parallel bands with the

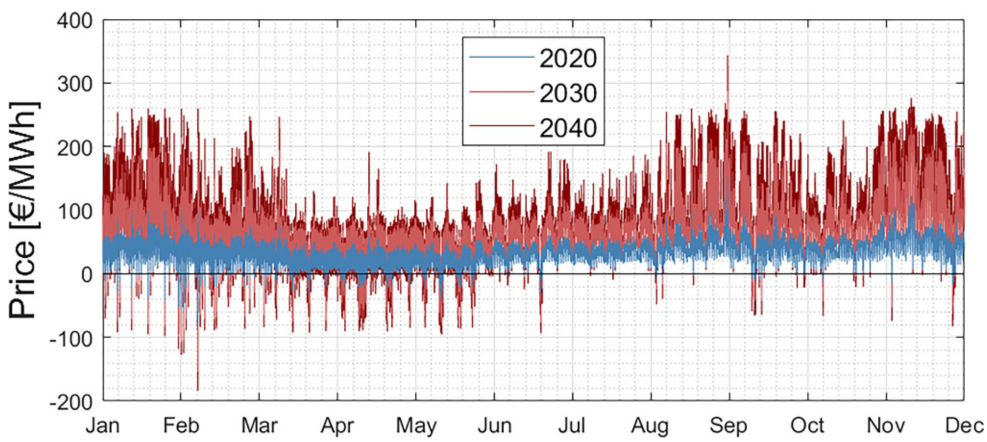

Fig. 1 Historic electricity spot market prices 2020 and price forecasts for 2030 and 2040 [9]

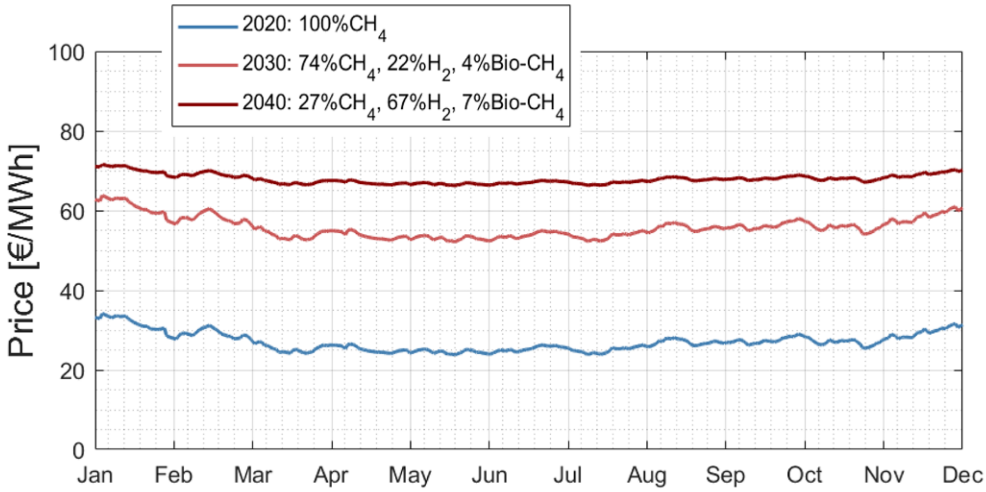

Fig. 2 Historic natural gas spot market prices 2020 and price forecasts for possible gas mixtures in 2030 and 2040 [9]

same provision values for positive and negative control capacity. Again, the required total capacity for each time step settles the market and defines which from the ranked bids to take [33].

In this work, we have included capacity-provision by the investigated technologies for both markets, FCR, and a/mFRR, into the optimization. The revenues from capacity activation we calculate during post-processing. However, to provide positive FCR- or positive a/mFRR services, GtP plants have to increase their power output, and PtG-plants have to reduce their power input. Providing negative FCR- or a/mFRR services demands the exact opposite approach.

The modeling of all prices for the considered services (FCR and a/mFRR) stands on historical data for 2020, openly available from the Austrian Transmission System Operator (TSO) Austrian Power Grid APG. The time-resolved data differentiate between capacity-provision and -activation. For modeling future prices, we use literature-based scaling factors for 2030 and 2040 [34, 35]. Those factors anticipate that in the future-electricity-system with high shares of Wind, PV, and Hydro-power, high volatility prevails. Which also means that future prices, especially for positive capacity activation, are expected to be significantly higher compared to 2020. From the future system behavior, we also assume that the demand for FCR and a/mFRR services will be such that the maximum capacity of the plants can be offered and activated (Table 1).

Traupmann et al. [9] provide more details about modeling all prices we considered in this work.

Table 1 Mean prices for FCR and a/m FRR for 2020–2040

[€/MWh]		2020	2030	2040
FCR	–	6.65	5.21	3.87
+aFRR	Reserve	2.51	5.21	4.50
	Activation	97.87	173.35	149.99
−aFRR	Reserve	2.44	1.98	0.08
	Activation	0.21	0.13	0.01
+mFRR	Reserve	3.57	59.85	57.17
	Activation	258.76	5395.10	5153.50
−mFRR	Reserve	3.25	3.96	0.28
	Activation	0.01	0.01	0.01

2.2 Multi-variable operation optimization model

In our work, we formulate a multi-variable mixed-integer linear optimization problem. We apply a multi-variable objective function (1) which maximizes the achievable profits *(P)* for each investigated technology (GtP, PtG, and GtP-PtG) for each time step and over an overall periode of one year. The objective function contains six decision variables: x_1 represents the plant's dispatch in the day-ahead spot market (for gas- or electricity). x_2 depicts the systematical FCR scheduling. While x_3 and x_4 stand for the positive and negative aFRR dispatch, the variables x_5 and x_6 represent the same for mFRR.

We calculate profits *(P)* out of revenues *(R)* (2) and costs *(C)* (3). While the latter result from fuel- (GtP) or, electricity costs (PtG), and OPEX in spot market operation *(C^{SM} and $C^{OPEX,SM}$)*, the former originate from the plant's collective operation in all the markets we previously described *(R^{SM} and $R^{B\&A}$)*. In terms of costs it need to be mentioned, that in the step of optimization, we do not take costs for capacity provision (x_2–x_6) into account. If the provided capacity is activated, we consider the accordant costs (fuel or electricity and OPEX) in the post processing. However, those costs are low, compared to the costs resulting from spot market dispatch.

$$\max_x \left(f\left(x_1, \ldots, x_6\right)\right) = \max_x \left(P\left(x_1, \ldots, x_6\right)\right) = \max_x \left(R\left(x_1, \ldots, x_6\right) - C\left(x_1\right)\right) \tag{1}$$

$$R\left(x_1, \ldots, x_6\right) = R^{SM}\left(x_1\right) + R^{B\&A}\left(x_2, \ldots, x_6\right) \tag{2}$$

$$C\left(x_1\right) = C^{SM}\left(x_1\right) + C^{\mathrm{OPEX},SM}\left(x_1\right) \tag{3}$$

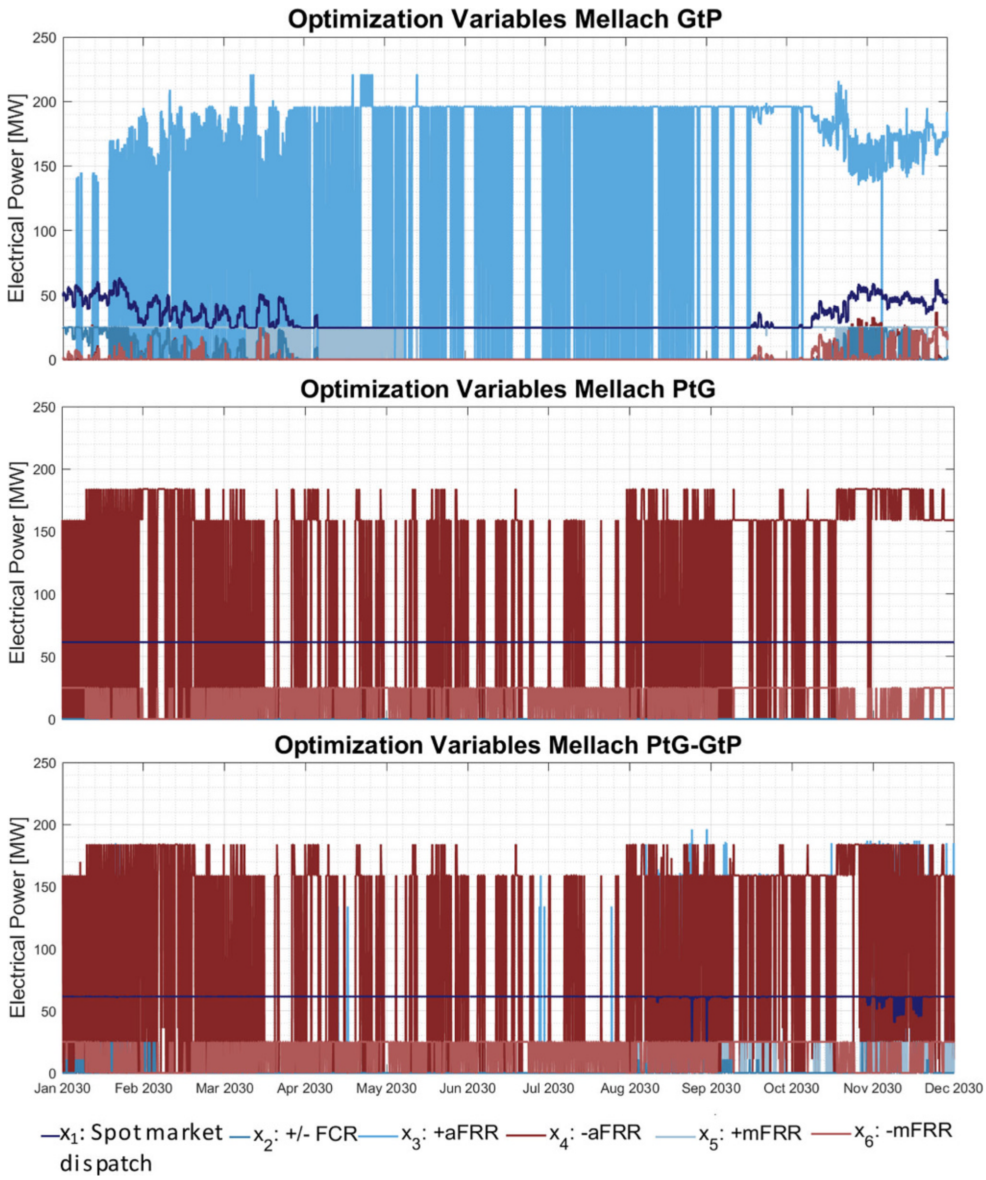

Fig. 3 Optimization variables for GtP, PtG and PtG-GtP for 2030 [9]

As an important constraint, the district heating demands to be supplied is taken into account in all cases investigated (c.f. Table 2). We also considered the ramp-up and ramp-down rates of each investigated technology and restrictions from the balancing- and ancillary service market rules, for instance, maximum (25 MW) and minimum (1 MW) bidding capacities on FCR and mFRR markets. An overview on all relevant modeling parameters is given in the appendix' *A* and *B*. With this approach, we can determine an profit-optimal multi-market operation schedule for each of the investigated technologies.

In a post-processing step we calculate the previously optimized profits together with additional costs for capacity activation against the annual CAPEX of the plants to determine their payback periods.

3 Results and discussion

3.1 Description of the investigated case study

As mentioned, we investigate in this work the repurposing of a decommissioned Austrian coal-fired power plant. Verbund's District Heating Power Plant (DHPP) in Mellach, south of the city of Graz. The Mellach plant provided around two thirds of the district heat demand of Graz. Table 2 summerizes the main plant parameter, relevant for this work.

Table 2 Main parameters of the DHPP Mellach

		DHPP Mellach
Rated Electric Capacity	[MW_{el}]	246
Rated Thermal Capacity	[MW_{th}]	230
District Heating Supply	[MWh_{th}]	746,658

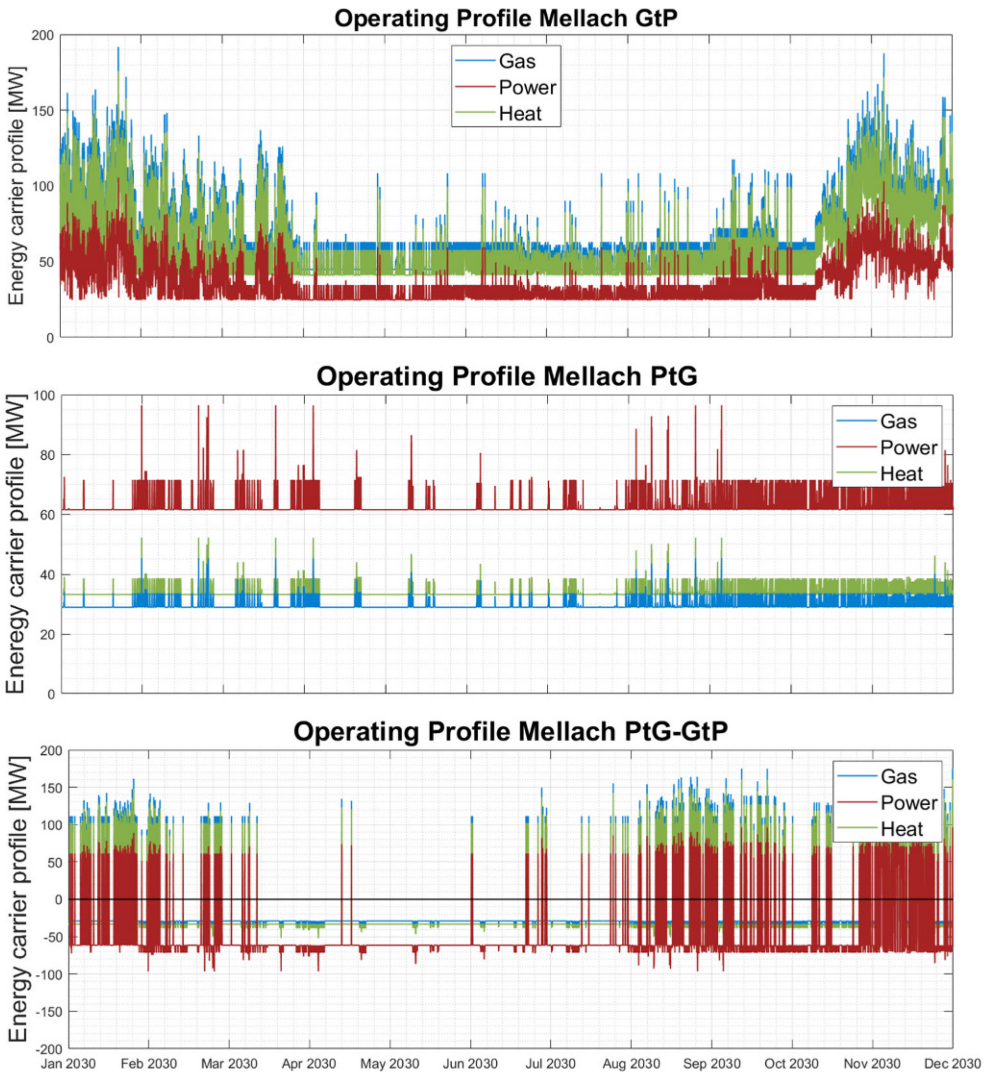

Fig. 4 Optimized operation profile for GtP, PtG and PtG-GtP for 2030 [9]

In our study, we assumed that the investigated technologies substitute the electrical capacity of the current Mellach plant. This means the GtP-plant offers an electrical output capacity of 246 MW, and the PtG-plant has an electrical input capacity of the same size. Regarding the district heat supply, we also assume that the same energy amount as today is delivered. No explicit delivery profile is given.

3.2 Optimized plant operation and economic analysis

In this chapter, we discuss results from our combined plant dispatch optimization in both spot- and service markets. In their work, Traupmann et al. pointed out that the applied combined optimization in which all optimization variables (x_1-x_6) are optimized at ones is favourable compared to a sequential optimization which optimizes the plant's dispatch in the spot market (x_1) first and the dispatch in the balancing- and ancillary service markets (x_2–x_6) second [9].

Fig. 3 shows the profiles of the six operation variables for each of the three investigated technologies for an exemplary 2030 use case. In general, balance and ancillary market dispatch dominate an operation in spot markets. Due to the modeled capacity constraints, the aFRR market is the strongest within them.

The optimization variables profiles for the balance- and ansillary service markets only depict capacity provision and not the actual capacity activation. This leads to differences between profile of the operation variables and the actual operation profiles. C.f. Fig. 3 with Fig. 4.

GtP-plants are operated mainly on the positive aFRR (x_3)- and the electricity spot market (x_1). The spot market operation couples with heat-delivery and leads to double-revenue situations: To fulfill the heat-delivery constraint, the plant provides a band-load-shaped profile with peaks in winter, in which favorable gas-electricity spreads occur. The plant's capacity is reserved in the +aFRR market throughout the year, especially in the summer (Fig. 3). Since the provided capacity is seldomly activated, the rated

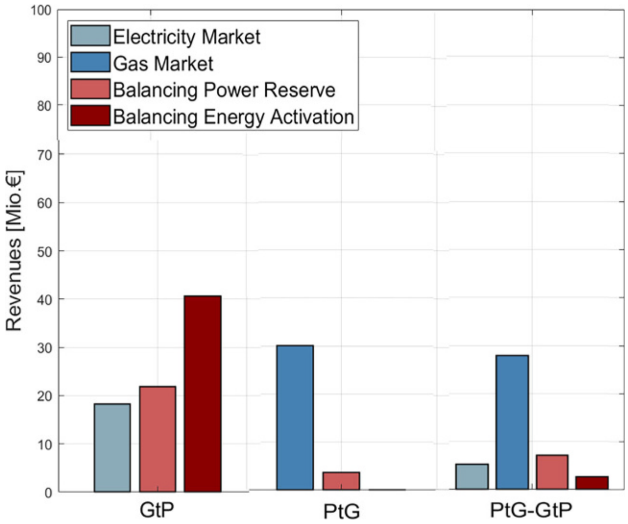

Fig. 5 Revenue streams for the investigated re-purposing technologies according to [9]

output of 246 MW is not reached, not even in the winter months with a maximum power output of around 100 MW. In total, this results in an operating profile similar to heat-operated power plants today but with lower power output in winter (Fig. 4).

Fig. 5 shows the revenue streams for the three investigated re-purposing technologies. Despite a high share of capacity provision for the GtP-plant, most revenues occur from capacity activation.

PtG-plants are operated mainly on the negative aFRR (x_4)- and the gas spot market (x_1). To provide negative aFRR services means in the PtG case to increase the plants' power input. Similar to the previous GtP case, the spot market operation couples with the heat-delivery constraint. In contrast to the GtP plant operation, no winter peaks occur (Fig. 3). The plants' capacity is reserved in the -aFRR market mainly in winter and, again, seldomly activated. Interestingly, capacity activation takes place mainly in the transitional seasons. Also, in this case, the rated input of the plant is not activated (Fig. 4).

The revenue streams of the PtG-plant are dominated by revenues from the gas spot market operation (Fig. 5). This is a result of the assumed high future gas prices. Revenues from the capacity provision are minor, and those from capacity activation can be neglected.

The revenue streams of the PtG-plant are dominated by revenues from the gas spot market operation (Fig. 5). This is a result of the assumed high future gas prices. Revenues from capacity provision is minor, those from capacity activation can be neglected.

Combined PtG-GtP-plants are similar to PtG-plants, operated mainly on the negative aFRR (x_4)- and the spot market (x_1). The reason is that the future gas spot leads to higher revenues compared to the electricity spot, which hinders GtP operation: In 93% of all time steps, the plant operates in PtG-mode. Due

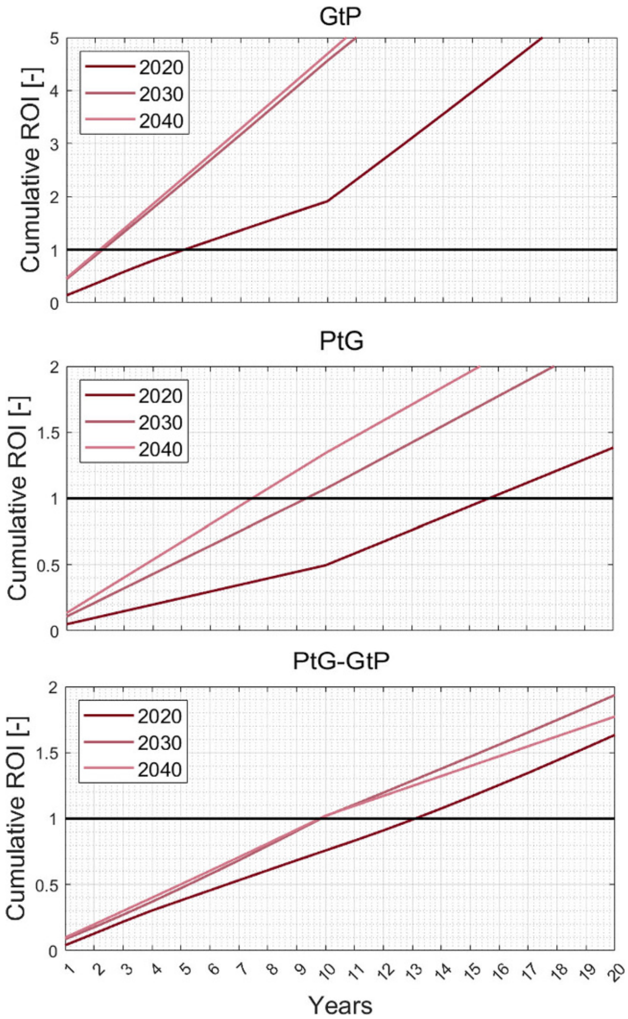

Fig. 6 Payback periods (cumulative ROI = 1) for the investigated technologies [9]

to this, the operation-variables profile (Fig. 3) looks similar to the one of the PtG-plant. A difference is the provision of positive aFRR (x_3) capacity during the summer and the transition season. However, the activation of this capacity takes only place very seldom.

Also, the view of the revenue streams (Fig. 5) leads to a similar picture as for single PtG-plants: Most of the revenues are related to the gas spot market operation. The opportunity to provide positive aFRR services generates some minor revenues for both capacity provision and activation.

Fig. 6 shows results from investment calculations. Based on the profit-optimized plant operation, we investigated the development of payback periods (return on Investment: cumulative ROI = 1) for each of the considered technologies over time (2020, 2030, and 2040).

For the GtP-plant, low CAPEX and high profits form a positive aFRR (x_3)- and electricity spot market (x_1) dispatch, lead to future payback periods of around one year. This makes the GtP-plant the most valuable re-purposing option compared to the investigated alternatives. The payback periods of PtG-plants decrease over time, mainly due to the CAPEX cost-down on the electrolyzer side. However, payback times of less than 7–8 years are not expected under the constraints of our study. The combined GtP-PtG plant faces the CAPEX of both components and a profit situation, similar to a single PtG plant. The calculated payback periods reflect this with a return on the investment only after approximately ten years.

3.3 *Influence of extreme price situations*

The Russian attack on Ukraine and Putin's accompanying use of energy in economic warfare has caused a surge in energy prices as never seen before. In 2022 mean day-ahead spot market prices of natural gas are around 100 €/MWh. Mean day-ahead spot market Electricity prices are about 200 €/MWh—c.f. Fig. 7. Compared to price forecasts performed before the Ukrainian war (c.f. Fig. 1 and 2), current energy prices are higher than anticipated for 2040.

We investigate how the current energy prices on spot markets influence the economic performance of the investigated technologies (GtP, PtG, and GtP-PtG). We want to focus on PtG technologies since we think they are a key technology in future energy systems. In our analysis, we apply only 2022 data for all relevant variables as spot market prices (Fig. 7), balancing- and ancillary service prices, CO_2 allowances, OPEX, and CAPEX. This allows us to fully depict the current situation.

Concerning the plants' operational profiles, the actual dispatch on the markets is similar to the 2030 situation from before. All considered plants show the main operation on both the spot- and the aFRR market. Compared to 2030, the current price situation allows for more spot market dispatch due to the intraday price spread between gas and electricity.

Table 3 shows results from an economic analysis based on the 2022 prices. Especially the results for the Power-to-Gas based technologies (PtG and GtP/PtG) are outstanding. These were considered to be future technologies before the war, not being deployed on a commercial scale very much before 2030. Since the individual technology components are not yet in competitive markets or, depending on the application, partly in early TRL-stages of 2–7, their CAPEX situation did only allow for pilot-plant installations in the past. As shown in Table 3, the current high energy price situation leads to payback periods for PtG plants, similar to the ones anticipated for 2040, even though CAPEX is still high.

Table 3 Economic analysis based of 2022 prices

	Annual ROI [–]	CAPEX Payback period [a]
Gas-to-Power (CCGT)	0.61	2.11
Power-to-Gas (Electrolysis)	0.12	8.28
GtP-PtG combination	0.17	6.45

4 Conclusion

Our main conclusion is that the current energy-market design allows for an economically sound future operation of both GtP- and PtG plants. Both technologies can outplay their advantages in providing positive- and negative multi-energy market services and, thus, foster the system implementation of volatile RES. An operation of combined GtP-PtG plants does not bring any economic advantages compared to single-technology units.

CCGT-based GtP plants will remain essential elements of the energy system. They can benefit from a combined operation on both the day-ahead spot- and the aFRR (automatic Frequency Restoration Reserve) market. The band-shaped spot market operation, in combination with district heat sales through the year, allows for basic incomes. The aFRR dispatch act as a quasi-capacity market and secures grid stability mainly in periods with low RES generation. Since we assume an increased RES deployment over the years, revenues from the capacity provision will

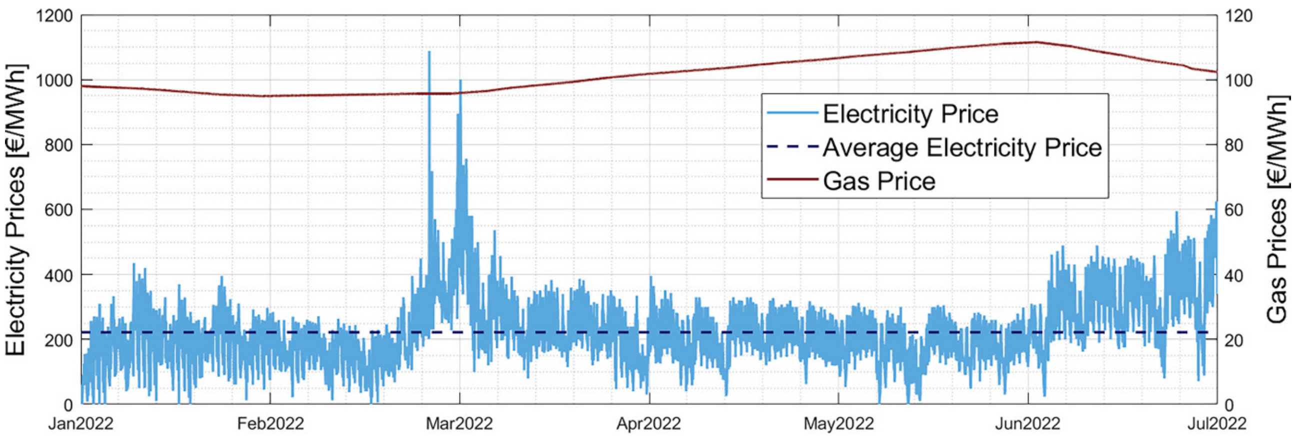

Fig. 7 Mean 2022 spot market prices for natural gas and electricity

also increase. This lead to higher cumulative ROI and lower payback periods.

An economic operation of PtG-plants is more challenging. From an operational standpoint, optimized profits result from band-shaped spot market gas sales and the provision of negative balancing- and ancillary service capacity. The band-shaped spot market operation requires a base load heat demand to cover. Price forecasts from before the Ukraine war allow for payback times of around 7–8 years in the year 2030. The high technology CAPEX stands in the way of a faster market deployment of PtG. Current energy prices, however, lead to payback periods as anticipated for 2040. Thus, an assumed high but stable future price situation on gas- and electricity spot markets may foster an early deployment of PtG plants. Investment subsidiaries would further reinforce this. From an energy system perspective, this would be very welcome:

- Firstly, future energy systems demand climate-neutral gases, mainly for usage in industry and parts of heavy traffic [36]. Domestic production reduces import dependencies.
- Secondly, the future deployment of volatile RES will lead to rising demand for seasonal storage services. In this regard, early PtG capacities are favourable.

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5 Appendix

5.1 *Appendix A: input parameters used in the optimization model of this work according to [9]*

Table A1 Parameters for Gas to Power plant modeling

Parameter		Gas to Power (GtP)		
		2020	2030	2040
Flexibility	(%/min)	1.67/2.33	1.67/2.33	1.67/2.33[2]
Power Range	(%)	10–100	10–100	10–100
Heat Production	(kWh_{th}/kWh_{el})	0.60	0.60	0.60
Efficiency	(%)	55	55	55
CapEx	(k€/MW)	805	740	700
Annual OpEx	(k€/MW)	32.2	29.6	28.0

Table A2 Parameters for Power to Gas plant modeling

Parameter		Power to Gas (PtG)		
		2020	2030	2040
Flexibility	(%/min)	20	20	20
Power Range	(%)	25–100	25–100	25–100
Heat Production	(kWh_{th}/kWh_{el})	0.54	0.54	0.54
Efficiency	(%)	33	47	49
CapEx	(M€/MW)	1.543	1279	1.113
Annual OpEx	(k€/MW)	26.47	21.99	19.29

5.2 Appendix B: composition of the optimization function and applied constraints according to [9]

Table B1 Composition of the optimization function

Objective Function Component		PtG	GtP
Revenues (€)	Revenues$_{\text{Spot Market}}$	$p_{\text{gas}} \cdot \eta_{c,\text{PtG}} \cdot x_1$	$p_{el} \cdot x_1$
	Revenues $_{\text{Service Markets}}$	$x_2 \cdot p_{\text{FCR},p} + x_2 \cdot p_{\text{FCR},n} + x_3 \cdot p_{\text{aFRR},p} + x_4 \cdot p_{\text{aFRR},n} + x_5 \cdot p_{\text{mFRR},p} + x_6 \cdot p_{\text{mFRR},n}$	
Costs (€)	Costs$_{\text{Spot Market}}$	$p_{el} \cdot x_1$	$\frac{p_{\text{gas}} \cdot 1.494 \cdot x_1}{\eta_{c,\text{GtP}}}$
	OpEx	$\text{OpEx}_{\text{PtG}} \cdot x_1$	$\text{OpEx}_{\text{GtP}} \cdot x_1$

Table B2 Modeling technology based constrains

Constraint		PtG	GtP
Spot Market	Start-up/power-down ramp	$-r_{\text{down,PtG}} \leq x_{1,k} - x_{1,k-1} \leq r_{up,\text{PtG}}$	$-r_{\text{down,GtP}} \leq x_{1,k} - x_{1,k-1} \leq r_{up,\text{GtP}}$
	Lower and upper bounds	$lb_{\text{PtG}} \leq x_{1,k} \leq ub_{\text{PtG}}$	$lb_{\text{GtP}} \leq x_{1,k} \leq ub_{\text{GtP}}$
	District Heat Supply	$P_{th,\text{PtG}} \cdot 0.25 \cdot \sum_k \frac{x_{1,k}}{P_{el}} = Q_{th}$	$P_{th,\text{GtP}} \cdot 0.25 \cdot \sum_k \frac{x_{1,k}}{P_{el}} = Q_{th}$
Service Markets	Lower and upper bounds ± FCR	$1 \leq x_2 \leq 25$	
	Lower and upper bounds ± aFRR	$5 \leq x_3, x_4 \leq ub_{\text{PtG}}$	$5 \leq x_3, x_4 \leq ub_{\text{GtP}}$
	Lower and upper bounds ± mFRR	$1 \leq x_5, x_6 \leq 25$	
	Constant power reserve 4 h	$\sum_{k=1}^{16} \frac{x_{2,\ldots,6,k}}{x_{2,\ldots,6}} = x_{2,\ldots,6}$	
Sum constraint positive FR products		$lb_{\text{PtG}} \leq x_1 + x_2 + x_3 + x_5 \leq ub_{\text{PtG}}$	$lb_{\text{GtP}} \leq x_1 + x_2 + x_3 + x_5 \leq ub_{\text{GtP}}$
Sum constraint negative FR products		$lb_{\text{PtG}} \leq x_1 + x_2 + x_4 + x_6 \leq ub_{\text{PtG}}$	$lb_{\text{GtP}} \leq x_1 + x_2 + x_4 + x_6 \leq ub_{\text{GtP}}$

Table B3 Modelling market constrains

FR Product	FCR	aFRR	mFRR
Minimum Bid Volume	±1 MW	5 MW	5 MW
Maximum Bid Volume	±25 MW	–	25 MW
Bid Increments	1 MW	1 MW	1 MW
Product Time Slots	6 Blocks of 4 h (sym-metrical)	6 Blocks of 4 h in each Direction (±)	6 Blocks of 4 h in each Direction (±)

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Thomas Kienberger, is the head of the Chair of Energy Network Technology at the Montanuniversitaet Leoben since 2014. In his research and teaching, he focuses on issues that aim to optimize energy efficiency and flexibility of public energy systems and energy systems along the value chain of the producing industry. His work always aims to provide quickly implementable, comprehensive contributions to the energy turnaround.

Anna Traupmann, completed both the bachelor's degree and the master's degree in "Industrial Energy Technology" at the Montanuniversitaet Leoben. Since October 2018, she has been working as a scientific project assistant at the Chair of Energy Network Technology at the University of Leoben. In the context of her dissertation, Ms. Traupmann deals with the modeling of the power grid for hybrid applications and investigates future impacts on the grids.

Roberta Cvetkovska, graduated in "Energy and Environment" at the Faculty of Mechanical Engineering in Skopje (Macedonia) and completed the master's program in "Industrial Energy Technology" at the University of Leoben. Since November 2020, she has been working as a scientific project assistant at the Chair of Energy Network Technology at the Montanuniversitaet Leoben. In the context of her dissertation, Ms. Cvetkovska deals with the scientific elaboration of hydrogen supply chains. Her work is strongly linked to the demand for renewable gases as a whole in order to determine the upscaling potential of green hydrogen via the research and creation of a new total energy system simulation with generation, distribution and use of the energy forms electricity, hydrogen as well as heat.