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Optimal operation of combined heat and power under uncertainty and risk aversion

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A R T I C L E I N F O

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A B S T R A C T

Despite the proven benefits of combined heat and power (CHP) and recently introduced subsidies to support it, CHP adoption has not met its targets. One of the possible reasons for this is risk from uncertain electricity and gas prices. To gain insights into the risk management of a CHP unit, we develop a multi-stage stochastic mean-risk optimisation model for the medium-term management of a distributed generation system with a gas-fired microturbine with heat recovery and a boiler. The model adopts the perspective of a large consumer that procures gas (for on-site generation) and electricity (for consumption) on the spot and futures markets. The consumer's risk aversion is incorporated into the model through the conditional value-at-risk (CVaR) measure. We show that CHP not only decreases the consumer's expected cost and risk exposure by 10% each but also improves expected energy efficiency by 4 percentage points and decreases expected CO_2 emissions by 16%. The risk exposure can be further mitigated through the use of financial contracts.

1. Introduction

Mitigating climate change has become one of the main drivers behind energy policies, especially in the European Union (EU), where the long-term stabilisation of CO_2 levels has become a priority. The EU aims to achieve 60–80% CO_2 emissions reduction by 2050 relative to 1990 levels by increasing renewable energy production and by significantly improving the energy efficiency on both the demand and supply sides [1]. However, since the deregulation of the electric power industry, private investments have been modest [2]. Thus, in order to attract investment for sustainable energy, the EU has had to introduce generous subsidies. This, in turn, has led to more volatile electricity prices and has posed severe challenges to the transmission network due to the intermittency of renewables. To alleviate these effects, it will be necessary to retain conventional generation for the foreseeable future. Nevertheless, it is widely argued that the current central-station paradigm for electricity generation is unsustainable in the long term as a result of low energy conversion efficiency and transmission losses [3–6].

A possible pathway for a sustainable energy transition is via the use of distributed generation (DG). As electricity is produced close to consumers, DG reduces transmission losses and allows for waste heat recovery. Thus, even though the electricity conversion rate for DG is lower than that of large power plants, the overall energy efficiency of DG system with a CHP is significantly higher [7,8]. For the aforementioned reasons, Germany has adopted three CHP laws to support investment into small- and large-scale CHP [9–11]. However, the targets regarding the higher share of cogeneration have not yet been achieved [12]. One of the possible reasons for lower than expected investment in CHP is uncertainties of electricity and gas prices in deregulated markets [13]. Financial risk is considered by [14,15] as one of the main barriers for investing in energy-efficient technologies. Likewise, Koller et al. [16] argue that middle-level managers show strong bias against risk as a result of flawed reward systems within companies.

In order to examine the risk that investors in CHP face, we formulate a multi-stage, mean-risk optimisation model for the medium-term management of a DG system with installed CHP. Our objective is to gain insights into managing risk using futures contracts and on-site generation. We assume uncertain electricity and gas spot prices and the availability of monthly and weekly electricity futures and monthly gas futures. We consider a large consumer that meets its electricity demand by either purchasing electricity from the markets or through on-site generation. In addition, the consumer satisfies its heat loads by using either a boiler or heat recovery. We find that the use of CHP not only lowers the consumer's expected running cost significantly but also reduces its risk

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exposure compared to on-site generation without heat recovery or to purchasing all electricity from the main grid. We also find that the availability of monthly gas futures increases on-site generation with CHP, thus indicating that CHP and gas futures are complements. *A priori*, the conditions under which physical and financial operational hedges function as substitutes or complements are neither evident nor explored in the extant literature. Hence, our modelling effort seeks to tackle this issue in order to provide managerial and policy insights that will be relevant for Germany and other industrialised nations grappling with a transition to more sustainable energy technologies.

The remainder of this paper is structured as follows. In Section 2, we provide a brief literature review of the related work. In Section 3, we introduce the decision-making framework and the problem formulation. Section 4 presents the numerical examples, and Section 5 summarises the main insights. Finally, conclusions are drawn in Section 6.

2. Literature review

Deterministic models for DG demonstrate that consumers with on-site generation can increase their energy efficiency significantly. Siddiqui et al. [8] compare the economic benefit of installing different types of DG at a hypothetical microgrid via the Distributed Energy Resources Customer Adoption Model (DER-CAM). Using mixed-integer linear programming (MILP), they find that investing in gas-fired CHP turbines leads to the lowest energy cost and also reduces CO_2 emissions. Focusing on the medium-term operational problem of an industrial consumer, Gómez-Villalva and Ramos [17] also use an MILP to determine the optimal scheduling for a CHP system. Meanwhile, Cano et al. [18] have a deterministic MILP for long-term strategic decision making in public buildings.

Studies with uncertain energy prices also exhibit the economic benefits of DG. Using real options valuations, Wickart and Madlener [19] find that, under higher price volatility levels, it is more profitable to invest in a CHP system than in conventional generation. Similarly, Siddiqui and Marnay [20] observe that high electricity price volatility relative to that of natural gas generation cost increases the value of a CHP investment.

While real options analysis provides insights into the investment decision, it does not address the operational risk of running a CHP under uncertain prices. One of the main mathematical tools used to model decision making under uncertainty is stochastic programming [21]. Stochastic programming is applied in [22,23] to examine the optimal operation of an electricity retailer and power producer, respectively. The electricity procurement problem of a large consumer with a self-production unit is considered in [24]. In a similar vein, Hochreiter et al. [25] approach the problem of a large electricity consumer facing uncertainty in electricity prices with the possibility of meeting its (deterministic) demand using spot purchases, supply contracts, and self-generation with a deterministic cost over a six-month horizon by implementing a multi-stage stochastic programming framework. Introducing CHP in a stochastic programming model, Eichhorn and Römisch [26] take the perspective of a risk-averse utility that must meet the stochastic electricity and heating demands of its customers via cogeneration, electricity spot purchases, and electricity futures purchases. Alipour et al. [27] tackle the day-ahead CHP scheduling problem of a risk-averse consumer facing uncertainty in electricity prices and demand with a deterministic self-generation cost. In contrast to the numerous deterministic and real options papers on CHP investment, Maurovich-Horvat et al. [28] apply stochastic programming to examine a consumer's prospects to invest in CHP.

Our research contributes to the existing literature as follows. Similar to [24–27], we examine the stochastic energy-sourcing problem faced by a large consumer, but we investigate how both the consumer's electricity and heat loads are met as well as the possibility of using CHP in addition to a microturbine without heat recovery. Furthermore, we assume that both electricity and gas spot prices are uncertain and futures prices are marked-to-market in every period, which is not the case in the literature that we have surveyed. Consequently, the interaction between physical, i.e., pertaining to equipment operation, and financial, i.e., dealing with forward contracts for both electricity and gas, hedges has not been adequately explored, thereby limiting managerial and policy insights. Analogous to [28], our paper provides insights into the interaction of financial hedges and on-site generation, but we focus on a consumer's risk management in the medium term instead of its long-term investment decisions. We also report on how different technologies can contribute to reaching the 2020 CO_2 emissions targets.

3. Decision-making framework

3.1. Assumptions

We address the operation of a DG system over a one-month time horizon that comprises four weeks. Each week is subdivided into T time periods of equal duration. The DG system consists of a gas-fired microturbine with heat recovery, a boiler unit, and deterministic electricity and heat loads (Fig. 1). The consumer can purchase electricity from the spot market and from the weekly and monthly futures markets. The monthly electricity futures have either an off-peak load, a peak load, or a base load profile, while the weekly electricity futures contracts can be purchased for base load and peak load periods. Moreover, the consumer can generate electricity using gas from the spot and monthly futures markets while recovering waste heat. Similarly, the consumer can produce heat with the boiler unit using gas from the spot and monthly futures markets.

To take into account possible risk preferences, we assume that the consumer's objective is to minimise its expected cost plus a risk measure with weight B. For the risk measure, we use the conditional value-at-risk (CVaR), which estimates the expected loss with a confidence level $A \in [0, 1)$ in the worst $(1 - A) \times 100\%$ of cases (Fig. 2).

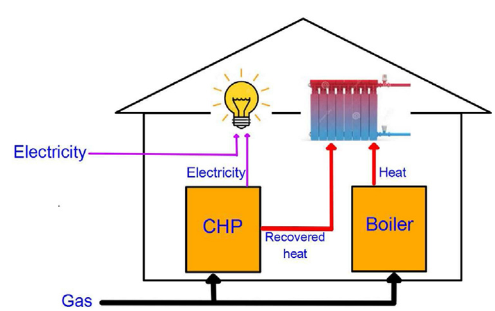

Fig. 1. Stylised distributed generation system with CHP.

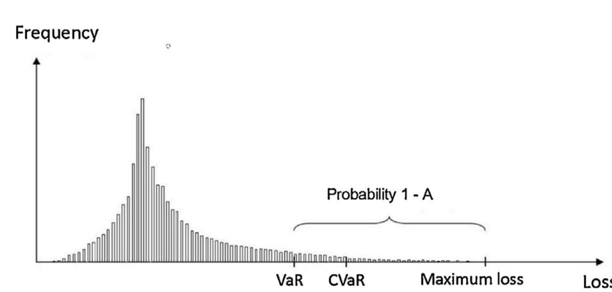

Fig. 2. CVaR in relation to VaR.