Incentivizing demand-side management, chances and risks for medium-sized industries

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Abstract:

Demand-side management (DSM) is a vital source of flexibility necessary for the increasing integration of variable renewable energy. And time varying electricity tariffs are widely proposed as an incentive for end users to utilize their potential. While existing literature focuses on residential users or energy cost intensive industries, this work investigates a medium-sized industry, a gravel plant. The plant has DSM potentials from its production processes as well as the potential to install Photovoltaics (PV). The system is modelled with an integrated optimization model for flexible processes and energy system and analyzed in three key aspects – total costs, emissions, and operation complexity.

Results show that with time varying electricity tariffs, the plant is directly exposed to high prices, which leads to a cost increase. The utilization of DSM, e.g. electricity price conscious production planning, reduces costs by 4.2 % and, coincidentally, emissions by 4.0 %, as carbon pricing weakly couples both objectives. It also increases the operation complexity as the plant constantly reacts to price fluctuations. The addition of PV significantly improves the system in all aspects; however, without further support, it may not be a viable investment for firms with limited capital. Lastly, it is recommended that the design of novel electricity tariffs should be tailored to user groups on the basis of their energy-related potential, their operational characteristics, and the acceptable level of risk exposure.

Keywords: demand-side management, time-varying electricity tariffs, optimization

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1 Introduction

As the share of variable renewable energy in energy systems increases, so does the need for flexibility, an ability of power systems to adapt to changes in demand or supply. Flexibility stems from various aspects of the system, e.g. novel market regulations, network expansion, flexible power plants, and from end-user technologies or processes [1]. The latter, generally understood as demand-side management (DSM), has significant technical potentials by supporting VRE integration [2]. To enable the use of DSM, end users must be financially incentivized to alter their operation plans to the state of energy markets or networks and to overcome additional costs or inconveniences incurred by the users [3]. One promising incentive is the time varying electricity tariffs, whose applications are well investigated for residential users or energy intensive industries.

Studies for small- and medium firms are scarce in comparison and thus present a research gap. This work investigates effects of time-varying electricity tariffs, flexibility potential, and technology expansion of a medium-sized industry with respect to total costs, operation complexity, and greenhouse gas emissions. Based on the results, recommended actions for end users and tariff designers are proposed.

2 Methodology

The work applies a scenario analysis under techno-economic assumptions of 2018. The evaluation is carried out in the period July – September due to data availability. This chapter elaborates the foundation of the work in three parts: a gravel plant as a case study, an integrated model forflexible processes and energy system and scenario frameworks.

2.1 Case study: a gravel plant

A gravel plant located near the river Rhine in Baden-Württemberg is chosen as a case study. The plant is of particular interest because of:

- its energy demand (electricity and transport fuel)
- its diverse production processes with material storage and with it flexibility potential
- its large area and therewith its high renewable energy potential.

In 2016, the plant consumed in total 3.6 GWh electricity and 4.9 GWh diesel for internal and external transport [6, 7]. The heating demand is estimated at 0.3 GWh [8], relatively small and thus excluded from the analysis. While the electrification of its transport fleets is a worth considering option for flexibilisation or decarbonization of the plant [9], it is currently deemed infeasible by the owner due to high costs and technical limitations of commercially available technologies. Therefore, this work focuses on the electricity sector. It is also worth noting that the plant is not qualified as an energy intensive industry according to [4, 5] and thus not eligible for regulatory advantages, e.g. a relief of *EEG-Umlage*.

The plant consists of multiple, interlinked processes which are grouped into three clusters: the extraction of raw gravel, gravel processing, and auxiliary processes, as shown in Figure 1. The plant operates on double shifts from 06:00 – 22:00 Monday to Friday. Thus far, it annually negotiates its fixed electricity price and has no incentive to neither assess nor develop its production-related flexibility potential.

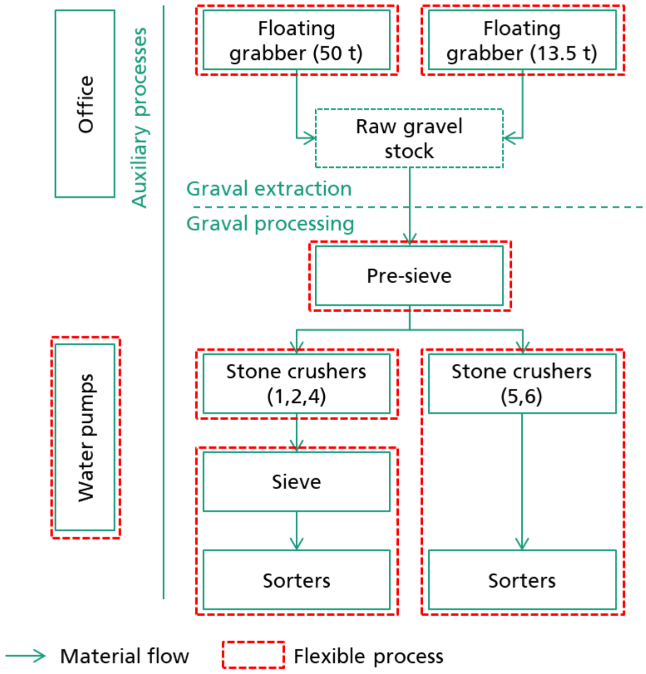


Figure 1 Process diagram of the case study, each node represents a process cluster with electricity demand except for the raw gravel stock which represents only material storage

2.2 Integrated model for flexible processes and energy system

Energy system models are typically developed as tools to analyze the optimal energy technology capacity expansion and operation. They often aggregate demand profiles together and thus disregard the finer operational characteristics of an individual process. The latter is crucial for the investigation of demand-side management (DSM) potential and is better represented by process models. Because this work focuses on both the investment of energy technologies and the use of DSM, an integrated model of a generic model for flexible processes GMFP and a local energy system model DISTRICT is developed.

The main goal of the DISTRICT [10] is to enhance and gain insights into local energy systems. Therefore, DISTRICT can model systems that represent individual buildings as well as whole communities. The model examines the systemic opportunities of electricity and heat cogeneration at the distribution level. The main objective is to find the cost-minimal system that fulfills certain criteria, such as 100% renewable energy, zero emissions or autarky of a system. The results of the model provide the system configuration as well as the path to achieve these criteria in a cost-minimal way. On a more detailed level, the operation of the deployed technologies is optimized and can be analyzed. A few boundary conditions have to be satisfied for the model to find the optimal system. The main condition is that the energy demand has to be covered by the energy generated at each time step. The model is able to present the industrial sector in detail, with each process represented as an individual entity and can therefore be shifted separately or an energy efficiency measure can be implemented. However, to analyze the flexibility options in more detail an additional generic model is developed.

A generic model for flexible processes (GMFP) is an operation optimization model representing possible physical and operation management constraints within any flexible processes [11]. In an abstraction, a process performs a conversion between quantities (inputs, outputs, and electricity) and consists of a machine, electricity and material storage. An operator is committed to an operation plan which dictates time and volume of the output production and delivery. Operators can change or shift the output delivery and with it alter the realized operation from the plan. The operation is also subject to working time, material delivery times, and external transport capacities. The GMFP allows a detailed representation of the underlying processes beyond their resulting demand profiles.

The electricity flow of the respective processes modeled by the GMFP is integrated into the electricity demand variable on DISTRICT, effectively linking both models. The model is formulated as mixed-integer linear programming, with the objective to minimize total costs including electricity procurement costs, emission costs, annuities from installed technologies, operating costs of energy technologies and flexible processes.

2.3 Scenario frameworks

Based on research and discussions with the plant owner, three scenario variations are identified – electricity tariffs, flexibility options, and energy technology expansion. They are elaborated in the following subsections.

2.3.1 Electricity tariffs

In 2018, an industry paid on average 17.96 €ct/kWh, which comprised of various cost components, notably procurement, network fees, levies, and taxes [12]. Although most small- and medium end users nowadays receive a flat-rate electricity price, this situation can change in the future. In fact, the regulatory framework for time-varying electricity prices already exists in [13] and some electricity providers already offer such options to end users [14]. This work considers three variations of electricity tariffs, namely:

- T0 (flat-rate), which establishes the status-quo
- T1, in which the procurement costs are time-varying
- T2, in which the procurement costs and network fees are time-varying.

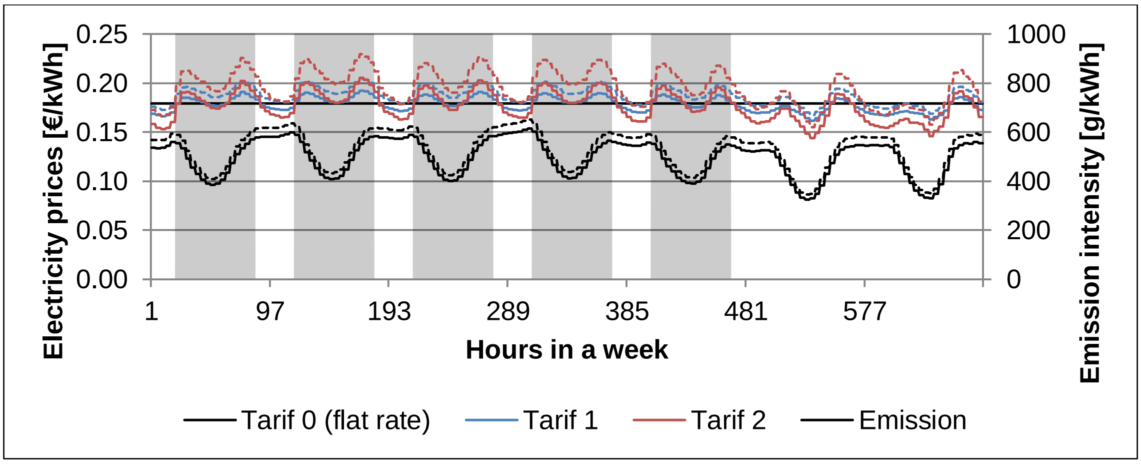


Figure 2 Average electricity prices and emission profiles over one week; the grey area highlights working hours of the plant; dashed lines represent profiles uncorrected for seasonal biases.

The price profiles are synthesized from the day-ahead EPEX spot prices [15],representing the shape and fluctuation and cost components referred to [12] determining the magnitudes. Originally, it was calibrated that annual averages of these tariffs were to be 17.96 €ct/kWh;

however, this revealed a seasonal bias as EEX prices during the evaluation period are generally higher than the rest of the year. Therefore, the profiles are seasonally adjusted so that their averages are equal during this period. Figure 2 plots weekly profiles of these tariffs.

2.3.2 Flexibility options

A process is considered flexible when its realized operation can deviate from a plan, be it by utilizing its internal storage, shifting the production plan, or changing operating parameters. For example, a significantly large gravel stock decouples gravel extraction (GE), i.e. floating grabbers, from gravel processing (GP) and allows processes to be planned separately. Similarly, gravel silos between pre-sieve and stone crushers allow operation to be shifted within 1-2 hours due to their limited sizes. Water pumps, which should provide constant water jet for gravel cleaning, can provide short-term flexibility by temporarily reducing their output followed by increasing it again. Through discussions with the plant owner, six processes were identified as flexible or potentially flexible. They are highlighted in Figure 1 with red dashed boxes.

The following lists four levels of flexibility utilization. Each level includes the potential of the previous.

- F0, no flexibility, operations follow original plans.
- F1, active daily production planning, in which the GE operation and 10% of the GP operation can be scheduled within the same day, i.e., their daily output remain as planned.
- F2, active weekly production planning, in which 20% of GE and GP operation can be allocated to adjacent days and flexible operation of water pumps, in which 10% of optimal water flow is deferrable and 5% is curtailable.
- F3, flexible shift schedule, in which the operating hours are changed to 05:00 – 21:00.

It is assumed that active production planning and changes in operating parameters do not affect the product quality or the wear-and-tear of the plant; therefore, no additional costs are considered. The option of F3 is likely to result in compensation for workers, but in absence of reasonable estimates it is assumed to be free.

2.3.3 Technology expansion potential

Taking into account the nature of production processes and energy demand, available area, and potential, Photovoltaics (PV) and lithium-ion batteries are of interest for expansion. An analysis reveals that the total PV potential is 1831 kWp consisting of 969 kWp on the roof and 862 kWp over the storage yard. The investment costs of rooftop PV are estimated at 900 €/kWp [16] and 1080 €/kWp respectively. Battery potential is assumed to be 2000 kW (kWh) at 1250 €/kW (kWh). Excess PV generation is sold at market prices without any premiums.

Furthermore, an essential input for the model is an hourly profile of emission intensity, which is processed from generation profiles of power plants in Germany [17] and their respective emission intensity according to [18], see Figure 2. The price of emission certificates is calculated at 25 €/ton. Table 1 shows eight main scenarios based on these variations. They are designed to examine the effects and influences of tariffs, flexibility options, and technology expansions.

Table 1 Descriptions of main scenarios

Scenarios	Electricity tariffs	Flexibility options	Technology potential
Business-as-usual (BAU)	T0	F0	-
Reference (REF)	T2	F0	-
Active tariff (ATX)	T1	F1	-
Active tariff+ (ATP)	T2	F1	-
Flexible production (FPX)	T2	F2	-
Flexible production+ (FPP)	T2	F3	-
Active energy (AEX)	T1	F1	PV
Active energy+ (AEP)	T2	F2	PV, Battery

3 Results and discussion

In this chapter, the results are presented in the following three sections. The sensitivity analysis is performed for selected aspects and presented in Section 0. In Section 3.5, findings and assumptions are discussed.

Table 2 summarizes key results, e.g. costs, emissions, and operation complexity. Figure 3 plots total costs by their components. Figure 4 plots weekly-averaged electricity import profiles of the *REF*, *ATP*, *FPP*, and *AEP* scenarios.

Table 2 Resulting key performances by scenarios

Scenarios	BAU	REF	ATX	ATP	FPX	FPP	AEX	AEP
Total costs [k€]	156.0	161.8	156.9	158.2	155.5	155.0	124.3	122.3
Emissions [ton]	379	379	365	367	360	364	213	207
Operation complexity [-]	1	1	0.7	0.8	0.85	0.87	0.67	0.82
Peak power [kW]	1427	1427	1551	1551	1564	1564	1538	1553
Electricity import [MWh]	815	815	815	815	804	804	462	451
Installed PV [kWp]	-	-	-	-	-	-	1831	1831
Electricity export [MWh]	-	-	-	-	-	-	148	147

3.1 Total costs

In the *REF* scenario, in which the plant is subject to a time-varying tariff (T2), the total costs amount to 19.85 ct€/kWh, 3.7 % higher than in the *BAU* scenario with a flat-rate tariff (T0). Results of *ATX* and *ATP* scenarios also show an increase of 0.8 % as the tariff changes from T1 to T2. In the *ATP* scenario, active daily production planning (F1) can reduce costs by 2.2 % compared to the reference. An additional flexibility F2 – active weekly production planning and flexible operating parameters – reduces costs by 3.9 %. The latter also considers the reduction in demand from water pumps curtailment, which contributes to a reduction of approximately 1.3 %. In the *FPP* scenario, an option to flexibly schedule operators' shifts reduces the total costs by 4.2 %, the lowest cost among scenarios without technology expansion.

In the AEX and AEP scenarios, the expansion of Photovoltaics (PV) is deemed economically feasible and thus its potential is fully exhausted. This results in a cost reduction of 20.8 % between *ATX* and *AEX* scenarios, i.e. given flexibility F1 and tariff T1, and a reduction of 21.4 % between *FPX* and *AEP* scenarios, i.e. given flexibility F2 and tariff T2. The *AEP* scenario has the lowest costs, 24.4 % lower than the reference. A PV investment changes cost components insofar as the plant bears annuities and operating costs, which account for up to 33% of the total costs in the *AEP* scenario, see Figure 3.

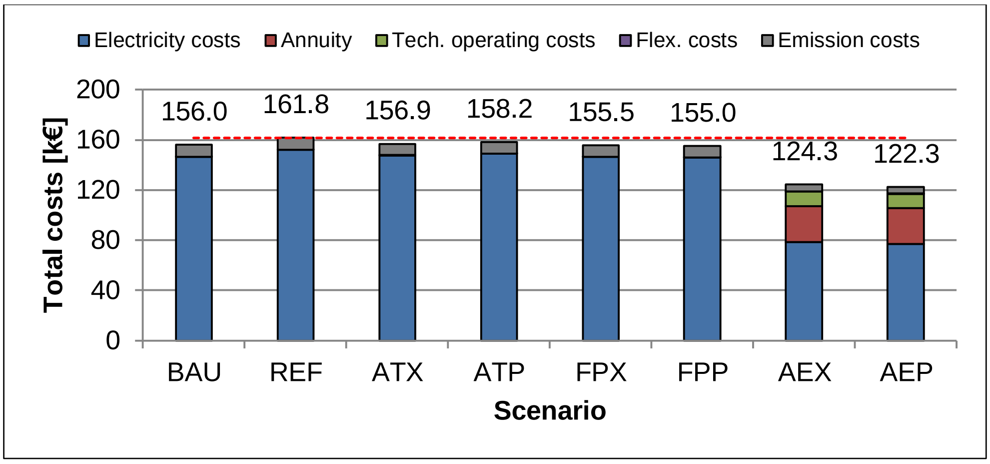


Figure 3 Cost components by scenarios; the dashed red line shows total costs of the reference scenario

3.2 Emissions from electricity import

In the *REF* scenario, electricity-related emissions amount to 379 ton (equivalent to 465 g/kWh). The utilization of flexibility options - F1 and F2 – in the *ATX*, *ATP*, and *FPX* scenarios lead to an emission reduction of 4.0 %. This is due to two factors - 1) high PV generation drives electricity prices and emission intensity down during midday 2) the internalization of emissions via CO_2 pricing - which weakly couple the cost minimization objective to the emission reduction. In the *FPP* scenario, however, emissions increase slightly because operation is partly shifted to the early morning (05:00 – 06:00) when electricity prices are lower than during the day, but emission intensity is also higher as coal-based generation dominates, see Figure 4.

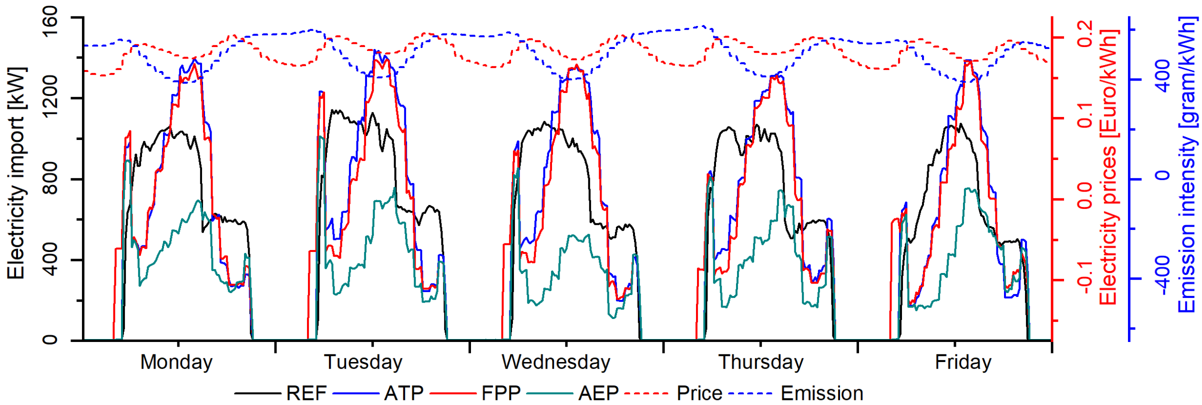


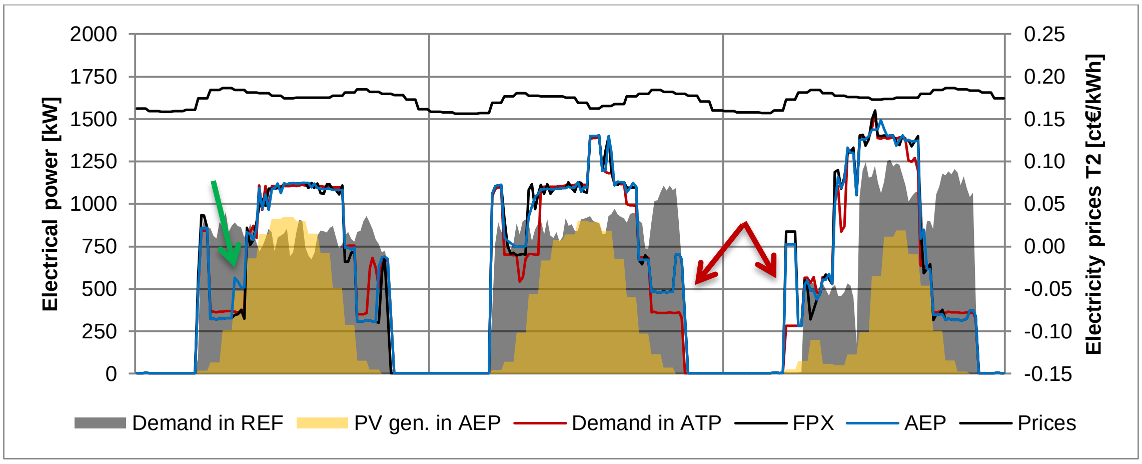
Figure 4 Weekly average electricity profiles by scenarios

3.3 Operation complexity

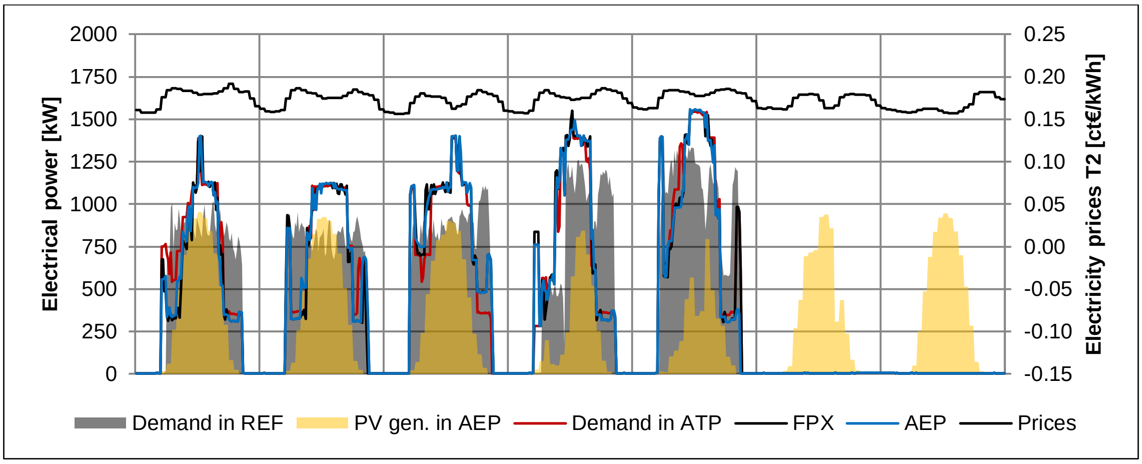
As the nature of operation varies from system to system, the operation complexity (OC) should be defined specifically for each system according to the judgements of system operators. This work defines OC simply based on how many times flexible processes are switched on relative to the reference. Moreover, it is worth noting that each shutdown is penalized with a small cost (0.25 ct€) to represent a delay in action. Such costs were not accounted for in the planned operation, which was derived from an actual operation (i.e. inflexible operation F0 in *BAU* and *REF* scenarios). On these accounts, a quantitative interpretation of this OC is inadvisable.

Results of the *ATX* and *ATP* scenarios show a higher OC as tariff changes from T1 to T2. This is due to a higher price fluctuation which incentivizes the plant to constantly react by switching off the machines more often, see Figure 5. The OC of the *ATP*, *FPX*, and *FPP* scenarios also increases gradually as flexibility potential increases (respectively F1, F2, and F3) - e.g. see red arrows in Figure 5 (a) - when processes are turned on and off. The presence of on-site generation (although inflexible) reduces dependence on external electricity and thereby the effects of price fluctuations, which leads to lower OC - cf. *AEX* compared to *ATX* and *AEP* to *FPX*, e.g. see a green arrow in Figure 5 (a) - when in the *AEP* scenario, flexible processes are turned on amid higher prices due to PV generation contradicting the *FPX* and *ATP* scenarios.

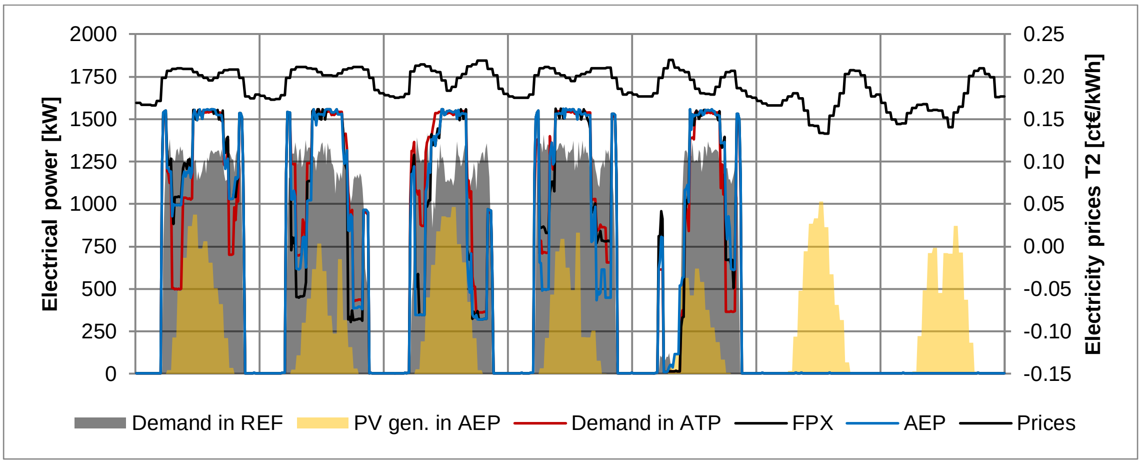
Results of the *REF*, *ATP*, and *FPX* scenarios show an increase in peak power as the flexibility potential increases. This is because all flexible processes simultaneously operate at full capacity during periods with low prices. In expansion scenarios, the investment in battery is not economical in the base year. Lastly, in the *AEX* and *AEP* scenarios, total electricity exports (excess PV generation) amount to 29.5 % of total generation (501 MWh). This is due to generation on weekends when the plant is not in operation, see Figure 5 (b) and (c).



(a)



(b)



(c)

Figure 5 electricity profiles of selected scenarios: (a) three arbitrary days, (b) a moderate production week, and (c) a high production week

3.4 Sensitivity analysis

Here, the results of the sensitivity analysis of selected parameters are discussed. Table 3 in the Appendix lists the full results of the sensitivity analysis scenarios.

<u>Photovoltaics (PV) Investment costs and amortization periods</u>

Based on the *AEX* scenario, investment costs vary within a range of ±15 %. The sensitivity analysis shows that the PV installed capacity is robust against changes of PV prices, i.e. the optimal capacity is 1831 kWp. The variation of PV prices leads to changes of total costs in the range of ± 3.5 %. According to the owner, an investment in a project should be made if its amortization period (AP) is at worst six years. Hence, scenarios are analyzed with the restriction that annuities are to be paid within 5 – 8 years. In view of the AP restriction by the owner, the project is not viable. However, if this condition is relaxed, i.e. to an AP of 7-8 years, the potential of rooftop PV could be developed.

<u>Volatility of electricity prices</u>

Based on the *REF* and *FPX* scenarios, its price profile (tariff T2) is modified by including a Gaussian random variable with a zero mean and a variance of 2.5, 5 and 10 % of 17.96 ct€/kWh to increase its volatility. Results show that the higher the volatility, 1) the greater the cost reduction from flexibility utilization, 2) the higher the operation complexity, and 3) the higher the CO_2 emission. The latter is because the introduced randomness overwrites the natural merit-order-effects of PV feed-in and decouples prices- and emission intensity profiles.

<u>Price of emission certificates</u>

Based on the *FPX* scenario, an emission price of 25 €/ton is varied to up to 50, 75, and 100 €/ton. Results show that by doubling and tripling the price, total costs rise respectively by 1.7 and 7.2 % and emissions reduce respectively by 0.4 and 0.9 %. As the emission price increases, an optimized operation progressively orients itself to the emission profile which is smoother than the price profile, see Figure 2 hence, the operation complexity reduces. By raising the price to 100 €/ton, emissions are further reduced to 356 ton. In comparison, the lowest achievable[2] emission is 353 ton.

3.5 Discussion

The results based on the case study show that users, especially double shift firms operating during peak hours, are directly exposed to high electricity prices and risks associated with time-varying tariffs. This leads to higher costs on their part if they are inflexible or lack on-site renewable energy potential. These tariffs also expose firms to the seasonality of energy markets, whose prices are generally higher in autumn than the rest of the year, as shown Figure 6. Since it is unlikely that firms can regularly change sales prices of products based on energy costs, they must be financially liquid enough to internally compensate for cost fluctuation throughout the year. This may be a problem for small firms or start-ups.

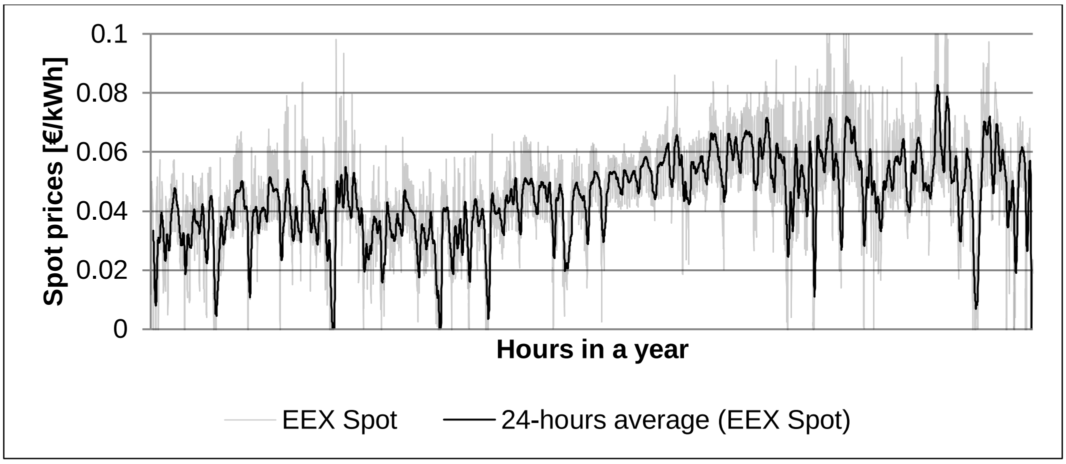


Figure 6 EEX spot prices in 2018, extracted from [15]

It is worth mentioning that the assumption "all tariffs average the same" in subsection 2.3.1 disregards many factors, among them, different risk premiums. Energy providers offering flat-rate tariffs include price premiums to protect themselves against the risks of price and demand fluctuation [19]. With a time-varying tariff, a part of these risks is passed on to users. Therefore its average could be lower than that of flat rate tariffs and subsequently, the total costs could be lower. Then again, one can argue that additional costs, from e.g. dynamic portfolio management or costs of smart meters associated with the provision of time-varying tariffs [20], could offset the benefits of lower risk premiums. Further studies on the costs of portfolio management and the necessary information and communication technologies are needed.

While photovoltaics (PV) significantly reduce both costs and emissions, its investment typically amortizes in 8 – 12 years and may be unattractive for small firms that prefer to (or even must) invest in projects with a shorter payback period. Besides, its investment is strongly weakened as generation on weekends cannot be used and are sold back to the market at a mere average price of 3 ct€/kWh. Political support - e.g. financial support or opening up local energy trading via peer-to-peer or power purchase agreement mechanisms

[2] This is calculated by setting an objective function as minimizing total emissions.

by reducing taxes or network fees – may be required to incentivize firms to develop their energy- and flexibility potential.

Lastly, the utilization of flexibility to minimize costs also leads to lowered emissions, except when operation is shifted to the early morning, which increases the use of coal-generated electricity. This is in line with [21] who found that on a national scale DSM does not necessarily lead to emission reductions. It is recommended that relationships between flexible operation and emission reductions in various firms be investigated. That said, the results speak in favor of emission pricing as a mechanism to incentivize firms to reduce emissions, in this case via flexibility.

4 Conclusions

In this work, a medium sized industry (a gravel plant) with flexibility potential from production processes and potential to expand its energy technologies is modelled with an integrated energy system and process model under time varying electricity tariffs. It is found that the double-shift operation plant is directly exposed to periods with high electricity prices; thus its total costs could be higher than in the case of a flat rate tariff. Nevertheless, flexible production planning can mitigate this and reduce costs by 4.2 % and coincidentally emissions by 4.0 %. Flexible operation that constantly reacts to price fluctuations is associated with higher operation complexity. In this case study, an investment in Photovoltaics (PV) is the economically and ecologically optimal measure despite the reduced profitability from total feed-in during weekends.

Given that novel tariffs shall incentivize end users to be more flexible, their designs should be tailored to each end user or user groups in order to maximize potential utilization, while at the same time mitigating excessive exposure to daily or seasonal price fluctuations, especially for small firms or startups. While a PV investment is economically viable without additional financial supports, it may not be attractive for firms with limited capital, which inevitably favor production-related projects with shorter payback periods (< 6 years).

5 Acknowledgement

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7 Appendix

Table 3 Key performances of sensitivity analysis scenarios

	Variations	Total costs [k€]	Emissions [ton]	Operation complexity [-]	Peak power [kW]	Electricity import [MWh]	Installed PV [kWp]	Electricity export [MWh]
Altered parameter: PV investment costs								
AEX	-15 %	120	213	0.67	1539	462	1831	148
AEX	-10 %	121	213	0.68	1539	462	1831	148
AEX	-5 %	123	213	0.68	1539	462	1831	148
AEX	+5 %	126	213	0.68	1539	462	1831	148
AEX	+10 %	127	213	0.69	1539	462	1831	148
AEX	+15 %	129	213	0.67	1539	462	1831	148
Altered parameter: amortization period								
AEX	5 yr	157	365	0.71	1550	813	6	0
AEX	6 yr	157	364	0.71	1549	811	18	1
AEX	7 yr	155	284	0.70	1539	625	969	75
AEX	8 yr	151	284	0.69	1539	625	969	75
Altered parameter: an emission certificate price								
FPX	100 €/ton	182	356	0.70	1564	804	-	-
FPX	75 €/ton	173	357	0.73	1564	804	-	-
FPX	50 €/ton	165	358	0.77	1564	804	-	-
Altered parameter: volatility of electricity prices								
FPX	2.5 %	155	362	0.90	1564	804	-	-
FPX	5 %	154	366	1.02	1564	804	-	-
FPX	10 %	151	370	1.26	1564	804	-	-
REF	2.5 %	162	379	1.00	1427	815	-	-
REF	5 %	161	379	1.00	1427	815	-	-
REF	10 %	161	379	1.00	1427	815	-	-