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INTEGRATING CO$_2$-ABSORBTION TO A BATCH-WISE PRODUCTION PROCESS – A CASE STUDY ON A SMELTER PLANT IN NORTHERN SWEDEN

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Abstract

This work presents results from an investigation of integration of carbon capture with a batch-wise operating process conducted through a case study on a large smelter plant located in northern Sweden with annual CO$_2$ emissions of approximately 300 kt/a. Separate capture plants for the two major sources of emissions, Process I and Process II, were conducted using detailed, continuous flue gas property data. These two units together account for about 70% of the site's total emissions. The plants were designed for a capture rate of 90% during peak CO$_2$ flow. One of the objectives of the study was to investigate opportunities to operate the capture plant using excess heat sources available on site. The plant dynamics were characterized by studying the magnitude, duration, and frequency of the variations of the site steam flows, as well as the production cycle lengths of Process I and Process II. The results indicate that the present site energy system can cover 31 - 40% of the capture plant's reboiler heat demand for capture from both Process I and Process II. This coverage increases to 54% for a future scenario. Neglecting the dynamics of the existing energy system only leads to a very small difference in heat demand coverage when both Process I and Process II are integrated with the carbon capture plant (31-40% with dynamics, and 31-42% without dynamics). However, when only the emissions from Process I are captured, the potential heat demand coverage for the existing energy system varies considerably (50% heat coverage accounting for dynamics compared to 100% without). Furthermore, for the future energy system scenario, the coverage of both units is 72% when dynamics are neglected compared to 54% with dynamics. These results clearly indicate the importance of considering dynamic operating characteristics in discontinuously operating processes. The smelter plant variations are characterized by time scales that are similar to the stabilization time of the carbon capture plant. The behaviour of the capture plant can thus not be fully characterized using a steady-state model (as used in this work), but this approach nevertheless provides an initial estimation of the design configuration and the share of heat demand which can be covered by the present process site energy system.

Keywords: *CCS, smelter plant, batch wise operating process*

1. Introduction

As the urgency of climate change mitigation becomes more apparent, so does the necessity of implementing carbon capture and storage (CCS) technology to mitigate CO$_2$ emissions in energy-intensive industry[1],[2]. One of the most investigated and technically mature carbon capture techniques is absorption using amine solvents, which has also been successfully implemented in full scale, see for example the Petra Nova[3] and Boundary Dam projects[4]. Monoethanolamine (MEA) is often used as a benchmark solvent. Most studies of carbon capture have focused on continuously operating processes such as power plants, cement production and oil refining - see for example[4],[6],[7]. Even though studies on the dynamic behaviour of a post-combustion capture plant have been conducted, for example connected to a steel plant[8], literature as well as research and demonstration projects on the integration of a CO$_2$ absorption process to discontinuous batch-wise operating processes are limited. An in-depth understanding of process dynamics is necessary to identify the optimal design of the capture plant and a suitable control system.

This study investigates carbon capture at a smelter plant located in northern Sweden. The plant consists of several smaller plants that are operated discontinuously with batch-wise processes. The total CO$_2$ emissions are about 290 kton/a of which 70% originate from two process units (hereafter denoted as Process I and Process II), which both release process-related carbon emissions that are not possible or difficult to mitigate through electrification or fuel shift. The smelter plant site thus presents an important and complex process for carbon capture due to the variations in both CO$_2$ flow and steam generation inherent to the batch-wise operation. As the regeneration of the amine solvent requires considerable amounts of heat (3.5-4 MJ/kg CO$_2$)[9] it has been shown that an efficient integration into the existing plant energy system is crucial to achieve acceptable levels for the specific capture cost[6],[10] .

The aim of this work is to identify the challenges, in terms of design and heat supply, related to integrating a capture plant with a discontinuously operated industrial process using a smelter plant as a case study. Furthermore, the work presents a method for characterizing variations in heat availability and demand.

2. Methodology

An overview of the workflow is shown in Figure 1. The work is based on hourly plant operating data for one year (September to August), as well as more refined measurements of flue gas properties (minute by minute) over 48 h for Process I and 65 h for Process II. The hourly plant operational data includes production of steam through heat recovery steam generators (HRSG), steam consumption of some units, as well as temperatures and flows in the condensers producing district heat and residual heat coolers. The hourly data is used to determine the heat that is available for the carbon capture plant, as further described in Section 2.2, as well as to characterize the dynamics of the energy network. The detailed flue gas data is used to characterize the dynamics of the flue gas properties, as well as to design the capture plants using a steady-state model of an aqueous 30 wt.% MEA process originally developed by Ósk Garðarsdóttir et al. in Aspen Plus V11[11], with recent improvements described further in Section 2.4. The results of the simulations are used together with the hourly operating data of Process I and Process II to estimate the heat demand of the capture process.

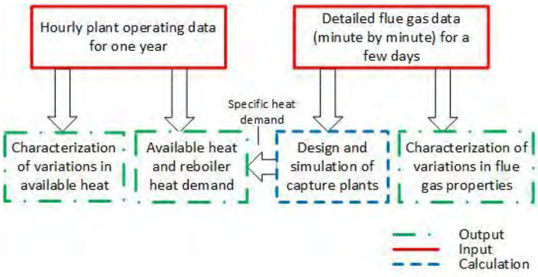

Figure 1: Overview of how the available data was utilized in this work. The red boxes show input consisting of hourly plant operational data over a year, as well as flue gas data for measurement periods of 2-3 days (minute by minute). The green boxes show the output of the work, while the blue box shows intermittent calculations (in this work simulations in Aspen Plus) utilized for several outputs.

2.1 Case study - Smelter Plant

Figure 2 shows an overview of the smelter plant process in which copper cathodes are produced from ore concentrates as well as secondary material such as waste material with high copper content. The material utilized in Process I is rich in carbon, causing about 60 kton/a of CO_2 emissions, which is about 20% of the total site emissions. The copper is refined in several steps, resulting in a number of by-products. Some of the separated material is treated in Process II through reduction with coal[12]. Process II emits about 140 kton/a of CO_2 corresponding to around 50 % of the total site emissions.

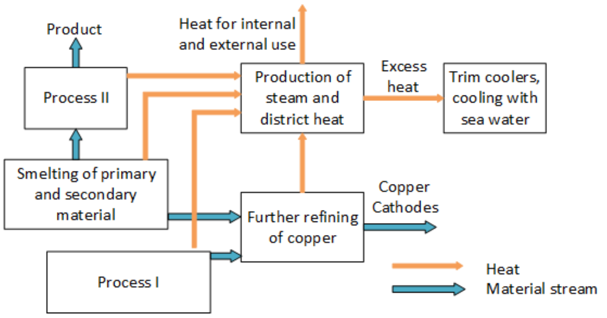

Figure 2: Simplified scheme of the processes at the case study smelter plant relevant to this work. The orange arrows indicate heat flows, while the blue arrows indicate material streams.

Both Process I and Process II are operated batch-wise, with flue gas CO_2 concentrations ranging from 0-15% in Process I, and 6-8 % in Process II. The total flue gas flow also varies during operation. For Process II the flowrate generally follows the same trends as the concentration. For Process I, the flue gas flow rate is stable during electronic waste feeding into the oven, but otherwise exhibits major fluctuations.

Steam is produced on-site in several heat recovery steam generators (HRSG), also operated batch-wise. The heat is utilized for generating steam (3-60 bar), which is used internally, e.g. to dry raw material, as well as externally for delivery of district heating or generation of electric power (primarily when heating demand is low), however, about 45 GWh/a is currently unutilized[12]. The excess heat is removed with sea water in trim coolers.

2.2 Heat supply to the capture plants

The heat considered available for carbon capture is hereafter referred to as “available heat”. Although the goal is to primarily operate the plant using heat available on site, the share of the capture plant’s heat demand to capture 90% of CO_2 which cannot be covered by the available heat is also quantified. Three scenarios with different levels of available heat were defined. Figure 3 displays the available heat over a year (Sep – Aug) in each scenario. The hourly distribution is displayed as filled areas, while the 720 hour (one month) moving average is displayed as a continuous curve. Scenario 1 considers the currently available heat, i.e. the amount of heat removed in the trim coolers. Scenario 2 also considers the steam currently utilized for electricity production in the condensing turbine and will, thus, constitute a loss of income from sales of electricity. The turbine is only operated during the summer season when the district heating demand is low. The available heat is thus equal for Scenarios 1 and 2 during a large part of the year. Scenario 3 considers the impact of planned process developments that will affect the steam demand and production on site in addition to scenario 2. The expected heat availability was determined through discussion with plant staff. As Scenario 3 is a future plant, operational data was not available. The available heat was estimated by multiplying the available heat of Scenario 2 with the expected total increase (in %) in available heat from Scenario 2 to Scenario 3.

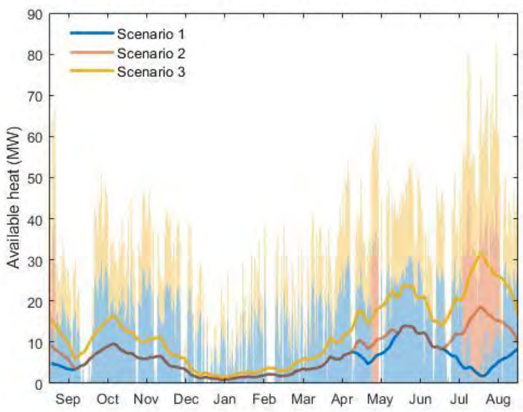

Figure 3: Available heat in Scenarios 1 (blue), 2 (red), and 3 (yellow). The filled areas display the actual heat availability for each hour during the year, while the curves show a moving average of the available heat over 720 h (one month). Note that the time period spans from September to August.

2.3 Characterisation of Process Dynamics

In order to design the capture plant and its control system, it is important to understand variations in heat availability and flue gas properties. As described in the work by Martinez Castilla et al.[8], the stabilization time of the capture plant may be several hours when subjected to changes in available heat and flue gas flow. In this work, the process dynamics for heat availability and CO_2 flow (Process I and Process II) of current operation were characterized based on magnitude, frequency and duration. The available heat data was obtained on an hourly basis. Flue gas property data measurements were available with shorter sampling intervals (minute). However, such data was only available for a shorter time period (48 h for Process I, and 65 h for Process II). Changes in flue gas property data on a minute basis were considered too frequent to be of interest to this study. Instead, the variations in the production cycles were studied.

2.4 Design and simulation

As the distance between Process I and Process II is too large to make it logistically possible to utilize a common absorber, two separate capture plants were designed. A standard configuration CO_2 absorption process was assumed, as shown in Figure 4. The capture plant was designed to capture 90% of the CO_2 in the flue gas during peak CO_2 concentration and flue gas flowrates. The reboiler duties of the two capture plants during full operation are 11.7 MW for Process I and 18.7 MW for Process II.

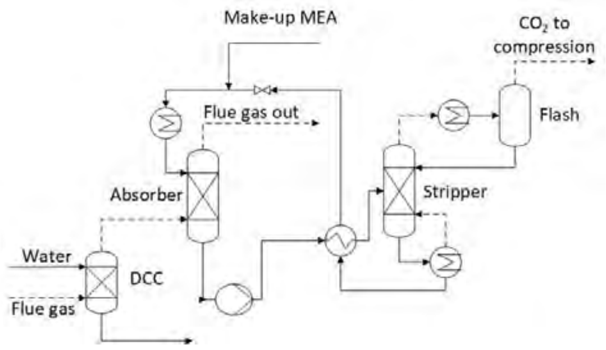

Figure 4. A simplified process schematic of a standard post combustion CO_2 absorption process using MEA solvent. The dashed lines indicate gas phase streams, while the continuous lines indicate liquid- or mixed phase streams.

The stationary capture plant model was originally developed by Ósk Garðarsdóttir et al.[11],[12] in Aspen Plus V8.2. The model is in this work run in Aspen Plus V11, and has been updated according to the most recent recommendations by Aspen Tech for Aspen Plus MEA-absorption modelling[13]. For the gas phase, Redlich-Kwong is used for calculation of equation of state instead of PC-SAFT, for easier convergence. Recent improvements include use of a V-PLUG flow model for the stripper and absorber units. In addition, kinetic reactions have been added to the stripper, which is also modelled in rate-based mode. All columns are modelled assuming KOCH FLEXIPAC structured packing. Pressure drops have been added to the columns and the model modified to account for the pressure drop for the rich stream in the lean-rich cross heat exchanger and the elevation from the absorber to the stripper. A direct contact cooler (DCC) modelled in rate-based mode has been added.

3. Characterization of variations in available process data

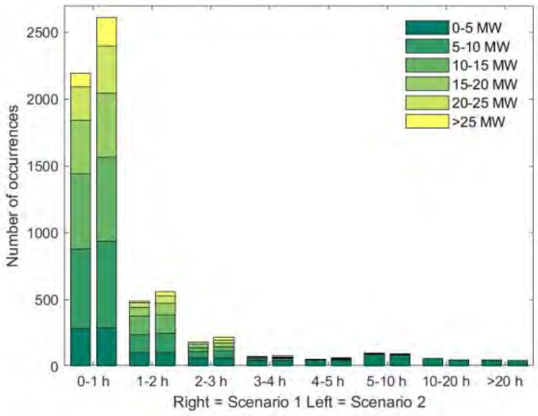

Figure 5: The number of occurrences over a year where the available heat remains within the same 5 MW interval throughout the durations of time indicated on the x-axis. The colours indicate the available heat of a certain occurrence.

Figure 5 shows the frequency of the variations in heat availability in the existing energy system on an hourly basis for Scenarios 1 and 2. The coloured bars indicate the heat amount available for the specific occurrence. Even though the interval used is 5 MW (around 10-15% of the maximum amount of available heat depending on what Scenario is used as a reference), the change between intervals are frequent. The amount of heat available rarely remains within the same interval for more than 3 hours or above 5 MW for more than 4 hours.

Figure 6 shows the distribution of the magnitude of the variation within each hour over a year. The hourly variation is often below 1 MW. However, about 25% of the hourly variations have a magnitude of 5 MW or more.

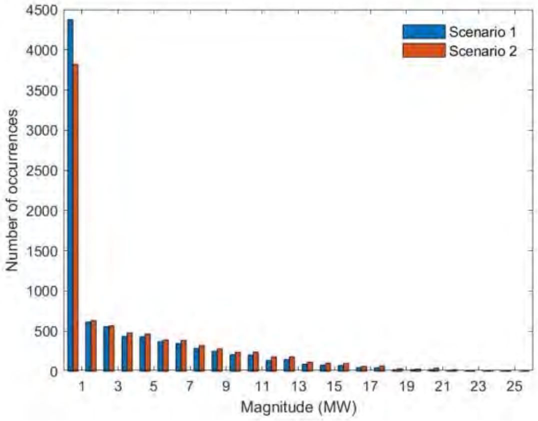

Figure 6: The distribution of the magnitude of the variations in available heat for Scenarios 1 (blue) and 2 (red) from hour to hour during a year.

Figure 7 and Figure 8 show the distribution of production cycle lengths for Processes I and II over 48 and 65 h, respectively. For Process II, the cycles range from 97 to 138 min and display a Gaussian distribution with a median of 122 min. For Process I cycles, it is difficult to discern any trend, and the cycles range from 140 min to up to 338 min, with a median of 166 hours.

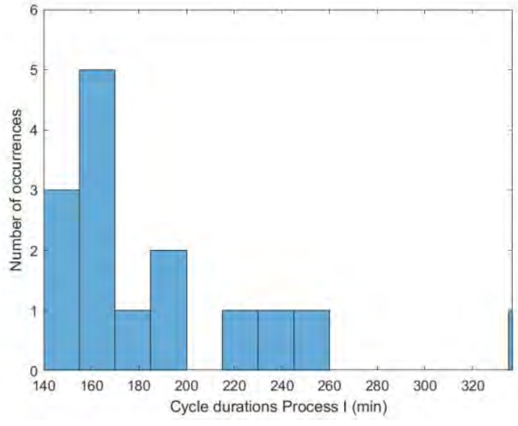

Figure 7: The distribution of the production cycle durations of Process I over 48 h.

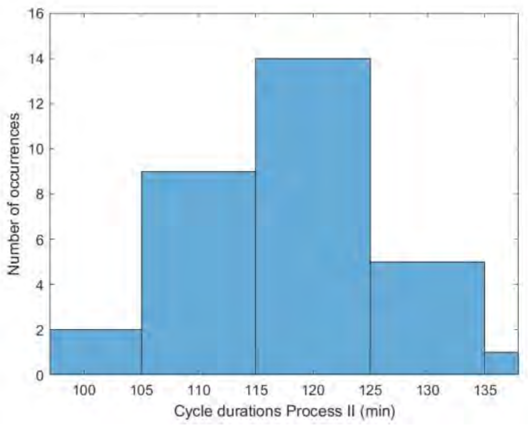

Figure 8: The distribution of the production cycle durations of Process II over 65 h.

In summary, there are significant and frequent variations in both the available heat and the CO_2 flow to the capture processes. The effect of the variations on the capture process differ depending on for example the size, piping length (residence time in the cycle) as well as the operational mode. Previous work on the dynamics of MEA absorption processes have indicated that the process has rather high inertia with stabilization times up to several hours for changes in heat availability[8], although this finding is somewhat depending on the location and sizing of solvent buffer tanks and the capture plant itself. With most significant variations in flue gas properties and available heat occurring within 3 hours in the concerned process, the capture plant will most likely not have time to stabilize. The combination of variations in CO_2 and heat availability further complicates any conclusions regarding the behaviour of the system based on the results of the steady-state model. To study effects of the dynamical behaviour of the available heat and flue gas on the capture plant, as well as to find the optimal design and control system, future work should involve dynamic modelling. The steady-state model used in this work, however, does provide a reasonable initial estimation of the heat coverage and design of the plant.

4. Results – Available heat for coverage of capture plant heat requirements

Table 1 displays the total availability of heat per year in the three scenarios. The available heat in Scenario 2 is 36% larger compared to Scenario 1. However, the additional heat is only available during summer when the steam turbine is usually in operation, as shown in Figure 3. Scenario 3 results in a 131% increase compared to Scenario 1. The estimated total heat demand during a year (September to August) are 43 and 107 GWh/a for Process I and Process II capture plants, respectively.

Table 1: Total yearly heat availability in the three scenarios. For Scenarios 2 and 3, the percental increase compared to Scenario 1 is also displayed.

	Scen. 1	Scen. 2	Scen. 3
Total availability	46.8	63.4	108.3

(GWh/a)			
Increase compared to scenario 1. (%)	-	35.5	131.4

In Figure 9, the heat load duration curves of Scenarios 1 and 2 are shown as continuous lines, while the reboiler heat demand, sorted to correspond to the heat load duration curve of Scenario 2, is shown as markers. The heat demand sorted after Scenario 1 is similar and thus not shown. Scenario 3 is not shown as it is simply a multiplication of Scenario 2. For both scenarios, heat is available to some extent for more than half the hours of the year. Scenario 2 has about 700 more hours with available heat than Scenario 1. A correlation between high demand and high availability is present in that there are few hours of zero demand when heat is available. This is expected as Process I and Process II are both heat and emission sources. There are, however, also a significant number of hours with high demand but too little or no available heat. These are hours when the steam produced in Process I and Process II HRSG is consumed internally or externally. This occurs when the demand of the district heating network is high, for example during wintertime, or when other units are not producing steam. There are also hours with a heat demand lower than the heat availability. Storage of steam in for example a steam accumulator could increase the potential utilization of this heat.

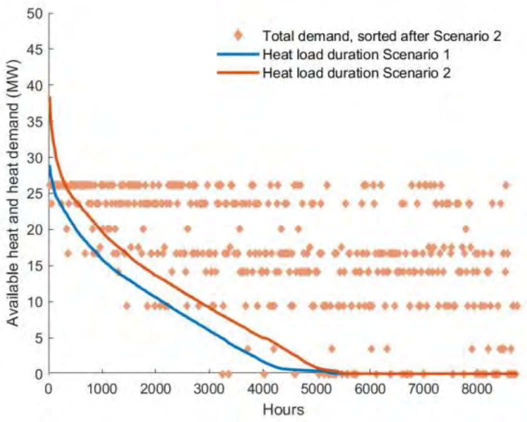

Figure 9: Heat load duration curves as continuous lines for Scenarios 1 (blue) and 2 (red). The markers indicate the heat demand for each hour sorted to correspond to the heat load duration curve of Scenario 2. The heat demand sorted after the heat load duration curves of Scenario 1 is similar. Scenario 3 is not shown, as it is simply a multiplication of Scenario 2.

Figure 10 displays the share of the reboiler heat demand covered by the heat available for carbon capture in Scenarios 1, 2 and 3 over a full year, if the available heat is utilized for capture from either Process I, Process II, or both units. Hours with zero demand are excluded, which is why the curves of Figure 10 do not reach 8760 h (one year). Table 2 gives the total coverage as well as the amount of additional heat required to cover the total demand of the capture plants to capture 90% of the CO_2 in the respective flue gases.

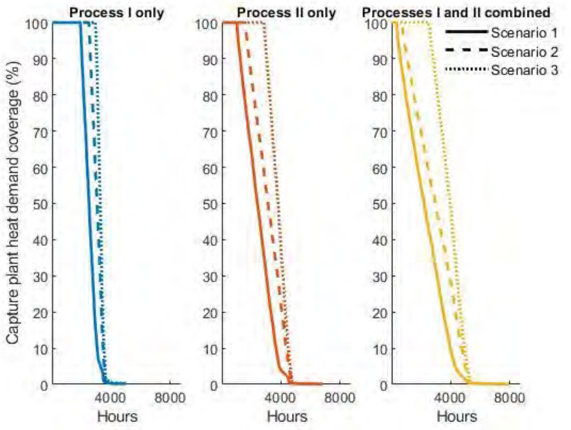

Figure 10:The share of heat demand covered by the heat available from the existing energy system in Scenarios 1 (filled line), 2 (dashed line) and 3 (dotted line) for capturing the CO_2 from Process I (blue), Process II (red) and both units combined (yellow).

Table 2: The total share of reboiler heat demand covered by the present energy system in Scenarios 1 and 2, as well as the future energy system in Scenario 3. The required heat addition to capture 90 % of the total emissions from Process I and Process II is also displayed.

	Process I only	Process II only	Both units combined
Total coverage Scenario 1 (%)	51.1	36.3	30.6
Required external heat addition Scenario 1 (GWh/a)	20.9	67.9	103.6
Total coverage Scenario 2 (%)	61.2	46.3	40.3
Required external heat addition Scenario 2 (GWh/a)	16.6	57.2	89.2
Total coverage Scenario 3 (%)	65.8	56.0	53.7
Required external heat addition Scenario 3 (GWh/a)	14.6	46.9	69.2

In Table 1, the total available heat in Scenario 1 over a year is 46.8 GWh, which should theoretically be sufficient to cover the total yearly reboiler heat demand for capture from Process I (42.8 GWh). However, according to the results displayed in Table 2, only about 50% of the reboiler demand is covered when comparing the available heat and demand hour by hour. A similar result can be observed for Scenario 3, where the total reboiler heat demand coverage for capture from both units appears to be 72% when dynamics are not considered, but only 54% when dynamics are considered. It can thus be concluded that it is highly important to account for the dynamic behaviour of the available heat and the reboiler heat demand. The quantification on an hourly basis may however also be considered a "worst-case" as it assumes that no heat may be stored – as opposed to the assumption that all excess may be stored which is implicitly assumed if considering the yearly average. The true heat coverage potential of the existing energy system is thus probably somewhere in between 50 and 100%. Additionally, the inertia of the capture plant as well as the steam network may result in a delay between the availability and demand. A detailed analysis of these factors is however beyond the scope of this study and left for future work. Furthermore, the capture plant has a cooling demand, and is therefore a heat source in itself. The heat can be recovered and utilized for example to produce district heating and could thus further increase the amount of heat that is available for the capture process, by decreasing the steam usage used to provide heat to the district heating network.

4. Conclusions

This work presented a feasibility study of the integration of carbon capture with a discontinuous batch-wise operating process, conducted through a case study of a large smelter plant in northern Sweden. The work investigated the heat integration potential for the smelting plant with carbon capture from two major emission sources, Process I and Process II. The operational dynamics of Processes I and II, as well as the available heat, were also characterized. The study concludes that there is potential for heat recovery from the smelting plant energy network to the carbon capture process. By only utilizing heat which is not currently used for other purposes (Scenario 1), 30% of the reboiler energy demand can be covered. If steam is redirected from the condensing turbine to the reboiler (Scenario2), about 40% can be covered, and with future process developments considered (Scenario 3), about 54% can be covered. In the three Scenarios, 104, 89 and 69 GWh/a in Scenario 1,2 and 3 respectively must be supplied by another source, requiring the addition of new steam generators to the current system.

The study also concludes that the dynamics of the plant have a significant impact on the heat recovery potential from the smelting plant to the carbon capture process. For carbon capture from Process I, 100% heat coverage appears to be possible if the yearly average is considered. However, this potential decreases to about 50% if hourly variations in the amount of available heat and reboiler heat demand are considered. Flexibility in the system through e.g. heat storage solutions is thus crucial to utilize as much heat as possible. The study also showed correlation between available heat and heat demand, in that the demand is usually high when the availability is high, pointing to the importance of studying demand and availability in relation to each other.

The frequency of changes in the amount of available heat, and the production cycle lengths are both comparable to the stabilization time of the capture plant (a few hours), and it can thus be concluded that the capture process will not have time to stabilize. The behaviour of the capture plant is therefore difficult to predict using only a steady-state simulation model.

Future work on discontinuous processes of this type could involve dynamical modelling, to gain better understanding of the behaviour of the capture plant when subjected to simultaneous changes in flue gas properties and heat supply. The heat integration study of this work only considers currently available steam, as well as planned process developments. The heat integration study can be extended, by considering additional potential heat sources on site, as well as excess heat recovery from the capture plant and heat storage options.

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