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Summary

In previous work, the heat savings potential that can be accomplished by increased heat recovery collaboration between the constituent companies was identified at the chemical cluster in Stenungsund. Based on this work specific measures to realize the potential were determined. All heat exchangers that can be included in a common heat recovery system were identified and other measures necessary in order to construct such a system were described. Detailed systems design, cost estimation, economic evaluation and cost sensitivity analysis was not dealt with in detail. A number of different systems solutions are available In order to identify cost-efficient system configurations it is important to develop a methodology that deals with design, cost estimation, economic evaluation and cost sensitivity analysis. The present study aims the development of such a methodology in order to enable decision makers to identify and compare cost-efficient and site-wide common heat recovery system configurations.

In a first step all the different cost items of the common heat recovery measures are identified. After that a short cut approach for estimating the different costs (HX, piping, pumps etc.) involved is applied. Later a methodological approach to identify the most cost efficient overall systems solutions is introduced. During this a number of promising options is identified, which then are evaluated in more detail according their economic performance.

As a result five promising systems were identified saving between 20.6 MW and 53.6 MW of hot utility. The estimated Pay Back Period (PBP) of the system was between 3.2 and 4.2 years. Further evaluation showed that especially two systems showed superior economic performance. System 20 recovering 20.6 MW of heat at a PBP of 3.2 years has the best Discounted Cash Flow Rate Of Return (DCFROR) of all systems (35.9 %). The retrofit only involves Borealis and Perstorp. Perstorp only serves as a sink for excess LP steam from Borealis, while recovered excess process heat is delivered from Borealis PE to Borealis Cracker. As it only enables for utilizing a minor share of the total heat integration potential it is considered as a first step towards a larger system.

The final step in the development of common heat recovery systems is System 50 recovering 50.8 MW of heat at a PBP of 3.9 years and a DCFROR of 27.8 %. This system shows the highest Net Present Value of all investigated systems and recovers a major share of the heat recovery potential. Three companies, Borealis, Perstorp and INEOS are involved in the retrofit. Borealis PE and Perstorp are mainly delivering excess process heat to Borealis Cracker, while INEOS solely servers as a sink for excess steam from Borealis Cracker. It is possible to extend System 20 towards System 50 if minor preparatory investments are taken.

Sensitivity analysis showed that only in two scenarios where the price of saved fuel decrease or the total investment costs increase by 30 % the PBP of System 50 exceeds 5 years and DCFROR drops below 20 %. The systems identified can be considered robust to fluctuations in investments costs and fuel price.

The methodology applied in this study was shown to enable for identifying cost efficient and economically robust heat recovery systems and even making it possible to describe staged investment paths where the simplest investments are taken first allowing for further systems extension in order to realize the a larger share of the heat recovery potential.

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1 Introduction

1.1 Background

The Stenungsund cluster is Sweden's largest agglomeration of its kind. The companies involved and their main products are AGA Gas AB producing industrial gases, Akzo Nobel Sverige AB producing amines and surfactants, Borealis AB producing ethylene and polyethylene (PE), INEOS Sverige AB producing polyvinyl chloride (PVC) and Perstorp Oxo AB producing speciality chemicals.The largest plant and the heart of the cluster is Borealis' steam cracker plant. It delivers both feedstock (mostly ethylene and propylene) and fuel gas to the surrounding plants. An overview of the site including the different plants and the material and energy flows between those is shown in Figure 1.

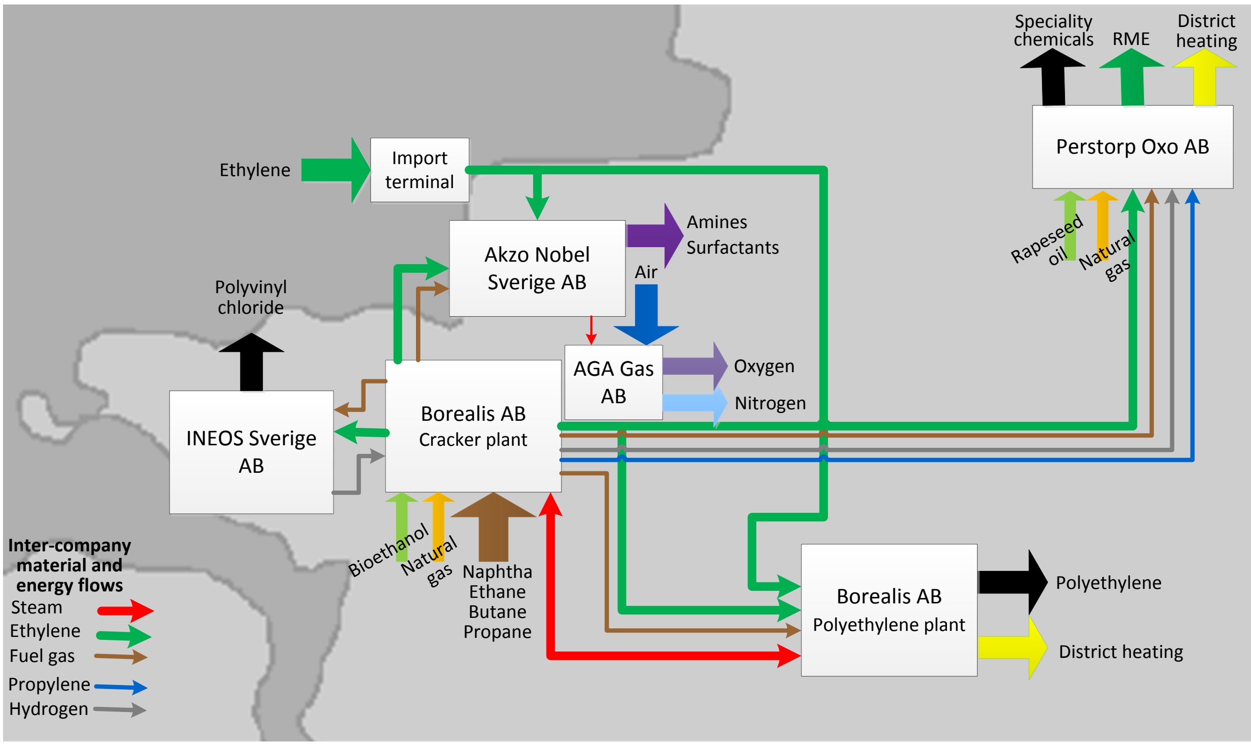

Figure 1 Material and energy flows across the chemical cluster in Stenungsund (Jönsson et al. 2012)

The companies already interact strongly with each other in terms of material exchange and are currently interested in investigating the potential for energy integration throughout the chemical cluster in Stenungsund.

Each plant has its own utility system and there is currently almost no colleboration in terms of heat exchange between the different plants. There are many different utility systems within the cluster, including in total 13 different steam levels (ranging from 85 bar(g) to 1 bar(g)), 3 different hot water systems, hot oil and flue gas heating together with water, air and refrigerant cooling. Table 1 shows the utilities used for heat recovery and process heating, together with the corresponding heat loads and amount of heat that has to be covered by external heat from the boilers (Q_{gen}-$Q_{consumed}$= approx. 125 MW). Waste heat from two plant sites is currently delivered to the local district heating system. The amount of fresh water consumed by the cluster is restricted and not allowed to increase with future site expansions (Hackl et al. 2011).

Table 1 Utilities currently used for heat recovery and process heating, values from data on TSA II (Andersson et al. 2011)

Utility	T [°C]	Q_{gen} [MW][1]	Q_{consum} [MW][2]	Q_{gen}-$Q_{consumed}$ [MW]
Steam 85 bar(g)	300	50.8	1.0	49.8
Steam 40 bar(g)	250	25.7	34.7	-9.1
Steam 28 bar(g)	230	0.0	8.2	-8.2
Steam 20 bar(g)	215	36.9	35.9	1.0
Steam 14 bar(g)	200	0.0	18.4	-18.4
Steam 10 bar(g)	184	30.7	26.6	4.1
Steam 8.8 bar(g)	178	27.3	87.3	-60.0
Steam 7 bar(g)	168	0.0	15.3	-15.3
Steam 6 bar(g)	163	0.6	17.2	-16.6
Steam 4 bar(g)	150	40.1	8.2	31.9
Steam 3 bar(g)	140	10.7	12.8	-2.1
Steam 2 bar(g)	131	55.2	117.2	-62.1
Steam 1 bar(g)	119	0.6	3.4	-2.8
Hot oil	277	0.0	2.0	-2.0
Hot water	160-50	9.0	13.3	-4.3
Flue gas	1400	0.0	10.4	-10.4
Sum		287.5	412.0	-124.5

[1]Utility generated from excess process heat
[2]Utility consumed in process heaters

In order to identify heat integration measures to decrease the hot utility demand of the total site Total Site Analysis (TSA) was used to determine the energy savings potential if heat is exchanged throughout the cluster via a common utility system. The results showed that by implementing a common hot water circuit, increasing the amount of LP-steam recovery and adjusting the utility levels in several heat exchangers all of the cluster's steam production from external fuel can be replaced by internal heat recovery.

Technical evaluation of the measures necessary for site-wide heat integration revealed a practical savings potential of 67 $MW_{hot\ utility}$, corresponding to app. 50 % of the clusters' overall hot utility demand provided by external fuel.

Two previous reports generated within the framework of the TSA project describe common heat recovery measures for the chemical cluster in Stenungsund (Hackl & Andersson 2010; Andersson et al. 2011). Andersson et al (2011) describes a number of different heat recovery measures, including a preliminary estimation of their economic performance. It was shown that there is a significant potential for cost-effective implementation of site-wide heat recovery systems in order to decrease the cluster utility usage and consequently its fossil fuel consumption. However, the design of the suggested measures as well as their economic performance was not investigated in detail.

Table 2 Heat source and sink data for a common hot water circuit (79/55 °C) - heat flow rate, estimated area of new heat exchangers and costs for new heat exchangers (total and per kW).

Rank	**Heat sources**	Plant	Heat flow rate Q [kW]	Estimated HX-area [m^2]	Estimated fixed capital costs [SEK]	Estimated HX-cost per kW [SEK/kW]
1	E443357	Borealis PE	6699	2280	19 909 960	2972
2	Kondensor HTC kolonn	INEOS	6000	1129	20 429 890	3405
3	Kondensor EDC kolonn	INEOS	3900	1430	17 206 831	4412
4	E443201	Borealis PE	13970	10429	66 792 499	4781
5	Kondensor HTC kolonn	INEOS	900	216	6 628 703	7365
6	E-1701 AX-DX	Borealis Cr	5458	6503	42 528 050	7792
7	E-442161	Borealis PE	12000	14297	107 536 516	8961
8	E-441161	Borealis PE	8800	10484	101 763 267	11564
9	E-2 (T-2201)	Borealis Cr	500	596	7 991 890	15984
		Sum	**58227**	**47364**	**390 787 606**	
	Heat sinks					
1	E1608	Borealis Cr	2500	134	3 577 036	1431
2	E-1845 A/B	Borealis Cr	21230	3596	33 487 290	1577
3	E-1890	Borealis Cr	3090	445	8 087 399	2617
4	Air to dryer PM8	INEOS	500	60	1 420 622	2841
5	Fluid dryer	INEOS	400	73	1 619 102	4048
6	Air to dryer PM8	INEOS	1300	424	5 356 664	4121
7	Air to dryer PM7	INEOS	700	190	3 104 715	4435
8	HPPE4	Borealis PE	260	30	1 283 415	4936
9	Luft till strömtork PM9	INEOS	528	143	2 562 985	4854
		Sum	**30508**	**5095**	**60 499 228**	

The common heat recovery systems identified were two hot water (HW) circuits (one low temperature system operating between 55 and 79°C, and one high temperature system operating between 75 and 97°C) which recover heat from sources where heat is currently discharged to cooling water (CW) or air and transfer it to heat sinks which are currently heated with hot utility generated in the cluster's boilers. Table 2 and Table 3 show the Heat eXchangers (HX) identified for supplying and utilising heat to and from the HW circuits. The tables show detailed information about heat flow rate, estimated HX area, and estimated capital costs. The heat sources and sinks are ranked according to their capital costs per unit of heat transferred. Also shown is the sum of heat available and heat demand for the two systems.

Table 3 Heat source and sink data for a common hot water circuit (97/75 °C) - heat flow rate, estimated area of new heat exchangers and costs for new heat exchangers (total and per kW).

Rank	**Heat sources**	Plant	Heat flow rate Q [kW]	Estimated HX-area [m2]	Estimated fixed capital costs [SEK]	Estimated HX-cost per kW [SEK/kW]
1	HPPE25	Borealis PE	6600	936	12 835 550	1945
2	56 Condensor	Perstorp	2600	205	6 104 387	2348
3	49 Condensor	Perstorp	1400	148	3 687 046	2634
4	47 Flashånga kondensor	Perstorp	500	53	1 830 675	3661
5	65 Rx1 kylare	Perstorp	4100	902	16 051 031	3915
6	16 Process cooler	Perstorp	16600	5820	70 066 532	4221
7	HPPE13	Borealis PE	4700	1600	20 038 678	4264
8	E-1712 A/B	Borealis Cr	500	102	2 488 825	4978
9	66 Rx2 kylare	Perstorp	600	107	3 757 830	6263
10	58 Kondensor	Perstorp	450	99	2 786 992	6193
11	E-6641	Akzo	500	58	3 458 399	6917
12	39 Processkylare	Perstorp	430	57	3 396 009	7898
13	14 Kondensor	Perstorp	3000	1004	23 982 796	7994
14	37 Processkylare	Perstorp	930	189	7 691 374	8270
15	6 Gaskylning	Perstorp	2300	919	22 579 610	9817
16	52 Condensor	Perstorp	500	119	5 629 127	11258
17	E-421433/434	Borealis PE	300	93	3 351 911	11173
18	34 Condensor	Perstorp	500	183	7 545 013	15090
19	38 Processkylare	Perstorp	400	191	7 748 946	19372
20	9 Gaskylning	Perstorp	800	953	16 663 708	20830
		Sum	**47710**	**13738**	**241 694 439**	
	Heat sinks					
1	Preheat demin	Borealis Cr	9700	1020	9 724 770	1003
2	V-5804 demin W preh	Borealis PE	2900	200	3 209 790	1107
3	E-1609X/E-1606Y	Borealis Cr	2400	117	3 255 757	1357
4	Condensate CT1701	Borealis Cr	3000	334	4 551 094	1517
5	E-1802	Borealis Cr	4055	1164	12 602 949	3108
6	E-1606Y	Borealis Cr	3875	1097	14 933 854	3854
7	24 Återkokare	Perstorp	5800	1166	23 242 387	4007
8	1 Gasvärmare	Perstorp	400	92	3 983 379	9958
		Sum	**32130**	**5190**	**75 503 980**	

Key conditions and limitations:

In the following conditions and limitations found during previous studies which are strongly influencing the design of common heat recovery systems are given.

It can be seen in Table 2 and Table 3 that there is more excess heat available than there is demand for both hot water circuits. The investment costs per unit of heat vary between the different HX:s. Costs for distributing excess heat throughout the cluster depend on the amount of heat recovery and on the location of the heat sources and sinks (length and path of the hot water pipes).

Primary energy savings are only achieved if the fuel consumption in one or more of the cluster's boilers is reduced as a consequence of implementing site-wide heat recovery measures.

Replacing hot utility by recovered process heat can cause an excess of utility (e.g. steam, fuel etc.) at one plant. This is the case e.g. if LP steam which is generated from process heat is replaced by recovered heat from the HW system[1]. If no other use for this LP steam is available no savings in primary energy can be achieved. Therefore additional investments are necessary for redistribution (e.g. steam piping between different plants) in order to enable utilisation of this utility (LP steam) at another plant.

If even the demand for excess utility at other plants within the cluster is met HX:s which currently use utility at an unnecessarily high temperature can be replaced by new HX:s enabling for increasing use of LP steam and therefore increasing the amount of heat recovery.

The overall systems costs are dependent on which combination of heat sources and sinks is chosen, to which plant(s) excess hot utility is transferred and if applicable, which HX:s are chosen to increase the demand for excess hot utility.

In summary, primary energy savings are only achieved if heat recovery leads to fuel savings in the cluster boilers. This is only the case when utility generated in the boilers is replace by recovered heat. Therefore utility replaced by recovered heat, which doesn't directly decrease the fuel demand has to be redistributed to a plant where it can replace utility generated in a boiler. The demand for such excess hot utilities can additionally be increased by replacing HX:s that use unnecessarily hot utility from a boiler by HX:s utilising excess hot utility.

To identify feasible and cost-effective designs of common heat recovery systems, it is necessary to conduct a thorough analysis of all the costs involved in each of the suggested designs.

In the following report a methodology for estimating the total systems costs for a number of different heat recovery system designs is presented. Revenues from such systems are determined as well as operating costs so that the different designs can be evaluated using the following economic indicators: Pay Back Period (PBP), Net Present Value (NPV) and Discounted Cash Flow Rate Of Return (DCFROR).

1.2 Aim

The aim of this report is to present a methodology for identifying feasible and cost-effective designs for common heat recovery systems in a chemical cluster. A large number of potential options are available and therefore it is necessary to determine the most suitable. As much information as possible must be provided for decision-makers in order to enable selection of the most suitable option also taking into account other factors such as operability and cross-company collaboration issues. The report also includes a number of possible common recovery system configurations for the chemical cluster in Stenungsund.

[1] Also boilers have a minimum load below which they cannot operate. If the boilers because of safety reasons cannot be shut down an excess of steam is cased, which has to be utilised in order to achieve primary energy savings.

2 Methodology

2.1 Determining total investment costs for implementation of common heat recovery system

2.1.1 Total investments costs

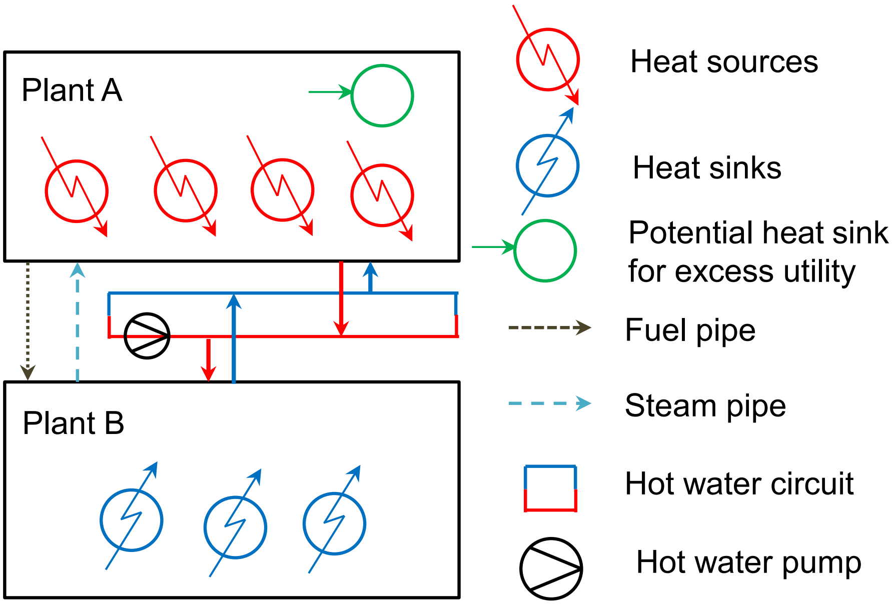

Figure 2 Illustration of all components necessary for implementing a common site-wide heat recovery system.

Figure 2 shows a graphical illustration of all the components necessary for implementing a common site-wide heat recovery system. Such a system consists of:

- HX:s delivering heat (heat sources) to a common HW system (red HX symbols)
- HX:s receiving heat (heat sinks) from a common HW system (blue HX symbols)
- HW pipe circuit between the different plants to transfer heat (red line: high temperature side/blue line: low temperature side))
- Steam piping between the plants to transfer excess steam between the plants (blue dashed arrow)
- Fuel piping to transfer excess by-product fuel gas between the plants (black dotted arrow)
- New HX:s that can utilise excess hot utility (green HX symbol) created when process heat recovery is increased and utility generation cannot be regulated directly by decreasing boiler load.
- HW pumps (black pump symbol)

The total fixed capital costs $C_{fixedCapital,tot}$ for heat recovery between different heat sources and sinks are calculated according to Eq. (1):

$$C_{fixed\ Capital,tot} = C_{heat\,source\,HX} + C_{heat\,sinks\,HX} + C_{HW\ piping} + C_{Steam\,redistribution} + C_{fuel\,redistribution} + C_{creating\,demand\ for\,excess\,utility} + C_{HW\ pumps} + C_{Heat\ loss\ comp} \quad (1)$$

with,

- $C_{heat\,source\,HX}$ = Costs for new HX necessary to deliver heat to a hot water (HW) system
- $C_{heat\,sinks\,HX}$ = Costs for new HX:s necessary to receive heat from a hot water system
- $C_{HW\,piping}$ = Cost of HW piping to transfer heat from heat sources to heat sinks (diameter and costs depending on the amount of heat that is transferred)
- $C_{Steam\,and\,fuel\,redistribution}$ = Costs of redistribution of excess steam and fuel between different plants (diameter and costs depending on heat the amount of energy transferred)
- $C_{creating\,demand\,for\,excess\,utility}$ = Costs for new HX to increase LP steam demand if steam savings exceed certain threshold. The cheapest new heater that can utilise LP steam is assumed to be used first etc.
- $C_{HW\,pumps}$ = Costs for HW pumps.
- $C_{Heat\,loss\,comp}$ = Costs for new HX to compensate for heat losses in the HW system

The underlying assumptions and data used for estimating the different parts of the total costs for heat recovery are described in the following.

2.1.2 Heat exchanger area and investment costs

2.1.2.1 Estimation of the heat transfer area of new HX

New heat exchangers have to be installed throughout the cluster in order to:

- Deliver heat to the common heat recovery systems
- Receive heat from the common heat recovery systems
- Utilise excess utility at lower temperature, thereby decreasing the demand for HP steam from the boilers which ultimately leads to fuel savings.

It is assumed that in all cases new HX:s will be installed. In certain cases it might be possible to modify existing heat exchangers. However, this option is not considered in this report. The capital cost estimates for implementation of a common heat recovery system in the cluster thus constitute an upper bound for these costs.

The HX area for new heat exchangers is estimated according the method suggested by (Sinnott & Towler 2009), as described below:

The general equation Eq. (2) for the heat flow rate transfer capacity is used to determine the heat exchanger area of new heat exchangers.

$$Q = U \cdot A \cdot \Delta T_m \tag{2}$$

with,

$$\Delta T_m = F_t \cdot \Delta T_{lm} \tag{3}$$

F_t = Temperature correction factor taking into account deviations from counter-current flow in Shell-and-Tube heat exchangers

ΔT_{lm} = Logarithmic mean temperature difference

$$\Delta T_{lm} = \frac{(T_1 - t_2) - (T_2 - t_1)}{\ln \frac{(T_1 - t_2)}{(T_2 - t_1)}} \tag{4}$$

T_1 = hot fluid temperature, inlet

T_2 = hot fluid temperature, outlet

t_1 = cold fluid temperature, inlet

t_2 = cold fluid temperature, outlet

$$F_t = \frac{\sqrt{(R^2+1)}\ln\left[\frac{(1-S)}{(1-RS)}\right]}{(R-1)\ln\left[\frac{2-S\left[R+1-\sqrt{(R^2+1)}\right]}{2-S\left[R+1+\sqrt{(R^2+1)}\right]}\right]} \tag{5}$$

$$S = \frac{(t2 - t1)}{(T1 - t1)} \tag{6}$$

$$R = \frac{(T1 - T2)}{(t2 - t1)} \tag{7}$$

***U*-value:**

The *U*-value (overall heat transfer coefficient) is determined using information about the flow characteristics of the service (utility) and process fluids circulating in the heat exchangers. Figure 3 is used to estimate the overall heat transfer coefficient *U*. Figure 3 provides typical heat transfer coefficients for different utilities and process fluids and can be used to estimate the overall heat transfer coefficient for Shell and Tube heat exchangers (Sinnott & Towler 2009).

Now Eq. (2) can be used to calculate the heat exchanger area *A*.

The calculated area is then increased by a factor of 1.25 to account for increased area demand under certain operating conditions.

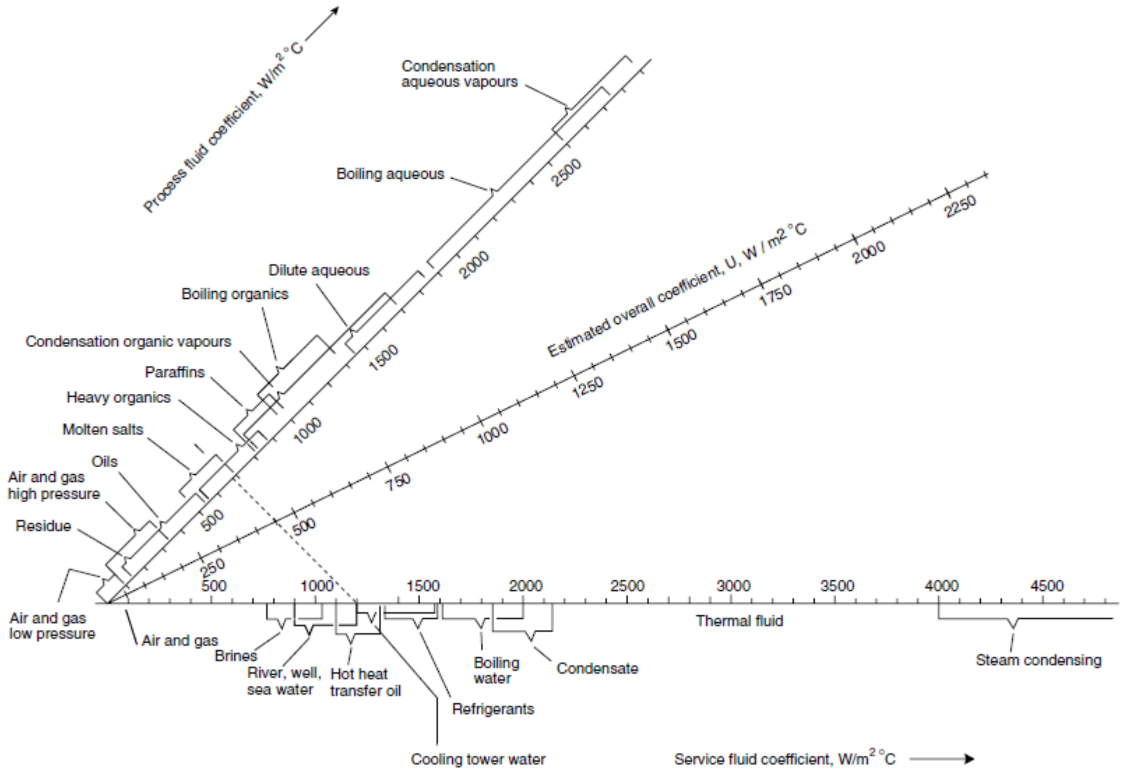

Figure 3 Overall U-values for different process/service fluid combinations in shell and tube heat exchangers (Sinnott & Towler 2009).

2.1.2.2 Estimation of heat exchanger investments costs

Investments costs for heat exchangers are determined according to the method for capital cost estimation for new design by (Smith 2005).

<u>Cost per HX manufactured using carbon steel (CS) material and operating at moderate pressure and temperature conditions:</u>

$$C_E = C_B \cdot (\frac{K}{K_B})^M \cdot CEPCI_{HX} \cdot SEK / US\$ \qquad (8)$$

- C_E = Cost for new CS heat exchanger with capacity *K* [m^2] operating at moderate *p* and *T* [SEK, 2012 money value]
- C_B =Known base cost [US$]; K_B =Base capacity [m^2] corresponding to C_B; M = constant depending on equipment type
- Acc. (Smith 2005) for shell-and-tube heat exchangers: C_B=32800 US$; K_B =80 m^2; *M*=0.68
- Max. area per heat exchanger: 4000 m^2, if larger area required an additional heat exchanger was assumed.
- CEPCI index for heat exchangers was used to update costs from 2000 (Index=370.6) to 2012 (Index=661.7), i.e. $CEPCI_{HX}$ = 661.7/370.6 = 1.784) (CHE 2012).
- SEK/US$ = 6.4 (2013-02-22)

The base cost estimated using Eq. (8) can then be adjusted using cost factors to correct for materials of construction, design pressure and design temperature, as well as standard installation cost factors:

$$C_{F,i} = \left[f_M \cdot f_P \cdot f_T \cdot (1 + f_{PIP})\right] \cdot C_E + (f_{ER} + f_{INST} + f_{ELEC} + f_{UTIL} + f_{OS} + f_{BUILD} + f_{SP} + f_{DEC} + f_{CONT} + f_{WC}) \cdot C_E \quad (9)$$

Cost factors used in Eq. (8) and Eq. (9) are listed in Table 4 and Table 5.

Table 4 Material, Pressure and Temperature factors for heat exchangers according to (Smith 2005).

Material	Factor f_M	Comments	Pressure (bara)	Factor f_P	Temperature	Factor f_T
CS	1		0.01 – 0.1	2	0 - 100	1
SS low grade	2.1	304SS,316 SS	0.1 – 0.5	1.3	100 - 300	1.6
SS high grade	3.2	322SS, 310 SS	0.5 - 7	1	300 - 500	2.1
Monel	3.6		7 - 50	1.5		
Inconel	3.9		50 - 100	1.9		
Nickel	5.4					
Titanium	7.7					
LTCS*	1.5	assumed				

***Low Temperature Carbon Steel (LTCS), cost factor for HX:s operating at sub-ambient temperatures, estimated after discussion with experts at Borealis.**

Table 5 Typical factors for capital cost based on delivered equipment costs (Smith 2005).

Factors from Smith (2005)	Factor	Comments
Equipment delivered cost	1	
Equipment erection f_{ER}	0.4	
Piping f_{PIP}	0.7	
Instrumentation f_{INST}	0.2	
Electrical f_{ELEC}	0.1	
Utilities f_{UTIL}	0.5	
Off-sites f_{OS}	0.2	neglected
Buildings f_{BUILD}	0.2	
Site preparation f_{SP}	0.1	
Total capital cost of installed equipment	**3.2**	
Design and Engineering f_{DEC}	1	
Contingency f_{CONT}	0.4	
Total fixed capital	4.6	
Working capital f_{WC}	0.7	neglected
Total capital cost	4.6	

After discussion with the participating companies “off-sites” (f_{OS}) and “working capital” (f_{WC}) cost factors were not included in the investment cost estimation. Off-sites usually include roads, auxiliary buildings, railways etc. which are not applicable for this kind of energy efficiency project. Working capital includes raw material and others necessary for start-up of a new plant. This is also not the case in this project.

2.1.3 Hot water piping costs for transferring heat between the different heat sources and sinks throughout the cluster

The diameter of the HW pipes was used to determine their costs. The temperature difference between the cold and hot side of the HW systems and the amount of heat transferred are used to determine the mass flow rate of HW water. The theoretical pipe diameter necessary to distribute the mass flow of water was calculated based on the fluid density and mean flow velocity data listed in Table 5. In order to keep the pressure drop in the pipes at a moderate level the mean flow velocity was assumed as given in Table 6. An engineering pre-study conducted previously at Borealis confirmed this assumption. The piping diameter was then selected to be the next standard pipe size available. A list of standard pipe sizes is given in Appendix 1. HW piping costs were then calculated based on the selected size, the distance between plants and cost data for district heating pipes.

Table 6 Data used for estimation of HW piping diameter and pipe length.

Description		Value	Unit
Density		965.4	kg/m3
Mean flow velocity in pipes		2.5*	m/s
Distance between plants [m]	PE - Cracker	2000	m
	INEOS - Cracker	1000	m
	Cracker - Cracker	300	m
	Cracker - Akzo	1000	m
	Perstorp - Cracker	4000	m
	PE - PE	200	m

*recommendation to avoid too high pressure drop (Engineering Toolbox 2013)

Cost functions are taken from a report by the Swedish District Heating Association (Nordenswan 2007). Different cost functions are available depending on the conditions where the pipes are to be installed ("Stadsmiljö" (urban environment), "Ytterområde" (suburban environment) or "Parkmark" (urban park environment). In a first estimate the highest cost ("Stadsmiljö") are assumed. CEPCI for pipes was used to update costs from 2007 to 2012 levels (913.8/733.6 = 1.246)

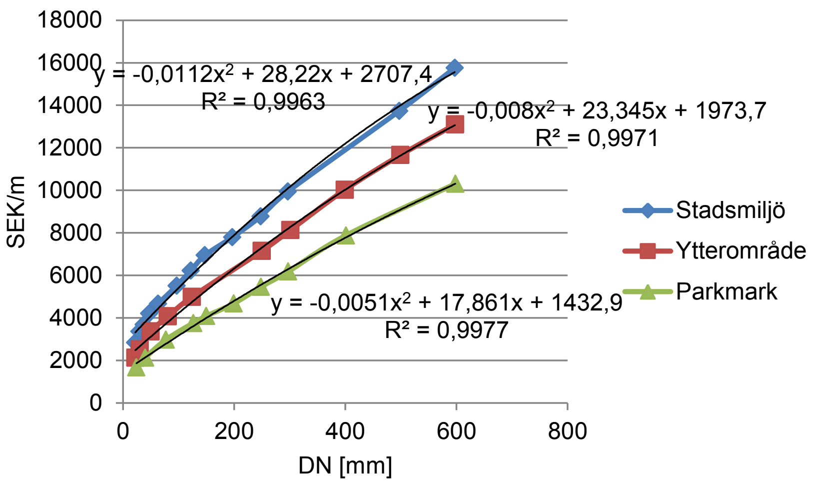

Figure 4 Cost functions for district heating pipes in different environments (Nordenswan 2007).

2.1.4 Piping costs for redistribution of excess steam

Steam pipe diameter is calculated based on the mass flow of steam necessary to be redistributed. Based on this the next larger nominal piping diameter was chosen to calculate the piping costs. The heat of vaporisation of steam at the corresponding pressure level and the amount of steam saved by heat recovery are used to determine the mass flow of steam.

In Table 7 data used for estimating the mass flow of steam and the necessary diameter of the steam and condensate piping to redistribute the steam. The length of the pipes was estimated based on the data given in Table 6 for the distance between the different plants.

Table 7 Data used to determine mass flow of steam, piping diameter and piping costs. Density and heat of evaporation taken for steam, flow rate assumed acc. to

Description	Value	Unit	Value	Unit
Pressure	2	bara	5	bara
Heat of evaporation	2202	kJ/kg	2108	kJ/kg
Density steam	1.129	kg/m3	2.668	kg/m3
Density condensate	958.6	kg/m3	915.3	kg/m3
Mean steam flow velocity in pipes	30*	m/s	30*	m/s
Mean condensate flow velocity in pipes	2.5*	m/s	2.5*	m/s

*Recommendation to avoid high pressure drop (Engineering Toolbox 2013)

Costs for steam and condensate piping are estimated using the procedure suggested by (Ulrich & Vasudevan 2006). The total grass root capital costs (C_{GR}) including pipes, insulation, transport to the site, pipe rack construction, piping assembly, equipment rental, labour, engineering, contractors fees, contingency, fees, site development and off-site facilities are calculated according to Eq. (10). The costs given by (Ulrich & Vasudevan 2006) are on mid 2003 basis and in US$. A CEPCI of 1.6 (CEPCI_piping 2012/mid 2003) and an exchange rate as shown in

$$C_{GR} = (F_{BM} \cdot C_{P,CS} + C_{BM,Ins}) \cdot (1 + F_C + F_F) \cdot (1 + F_{SD} + F_{OS}) \cdot CEPCI_{PIP} \cdot SEK / US\$ \qquad (10)$$

with,

- $F_{BM} = 11.6 \cdot D_{nom}^{-0.84} + 1.13 \cdot F_M \cdot F_P$ = Installation factor accounting for pipe transport to the site, pipe rack construction, pipe assembly, equipment rental, labour and contractor fees. D_{nom} = nominal pipe diameter (in cm), F_M and F_P are the material and pressure factor (in this case both factors are 1 since CS is used as piping material and a pressure of less than 10 barg is assumed).
- $C_{P,CS}$ = Piping base cost ($/m) depending on the pipe diameter as shown in Figure 5. In this case straight-run piping is used.
- $C_{BM,Ins} = 1.13 \cdot t_{opt} \cdot (D_{act} + t_{opt})$ = Cost of purchasing and installing insulation ($t_{opt} = 0.255 \cdot D_{nom}^{0.20} \cdot \Delta T^{0.65}$ = insulation thickness), D_{act} is the actual bare-pipe outside diameter (in cm) taken from piping tables (see Appendix 1), ΔT is the temperature difference between the bulk fluid temperature inside the pipe and ambient temperature (in °C)). Note that the factor originally given by (Ulrich & Vasudevan 2006) to calculate t_{opt} is 0.085. After discussions with the companies about the insulation thickness obtained by this method this factor was increased by a factor of 3 to account for colder climate and

higher energy prices in Sweden compared to USA in 2003. Low heat losses are also desirable, as the temperature in the HW system is not allowed to decrease significantly as otherwise heating of certain streams with HW is no longer possible.

- F_C = Contingency cost factor 0.15
- F_F = Fee factor 0.03
- F_{SD} = Site development cost factor 0.05
- F_{OS} = Off-site facilities cost factor 0.21 to account for maintenance roads and others when piping is constructed between the plants (Ulrich & Vasudevan 2004)
- $CEPCI_{pip}$ for pipes and valves (1.599) was used to update costs from mid 2003 (570.7) to 2012 (913.8) (CHE 2012).
- *SEK/US$* = 6.4 (2013-02-22)
- Costs for condensate pumping was not taken into account due to its minor contribution to the total cost

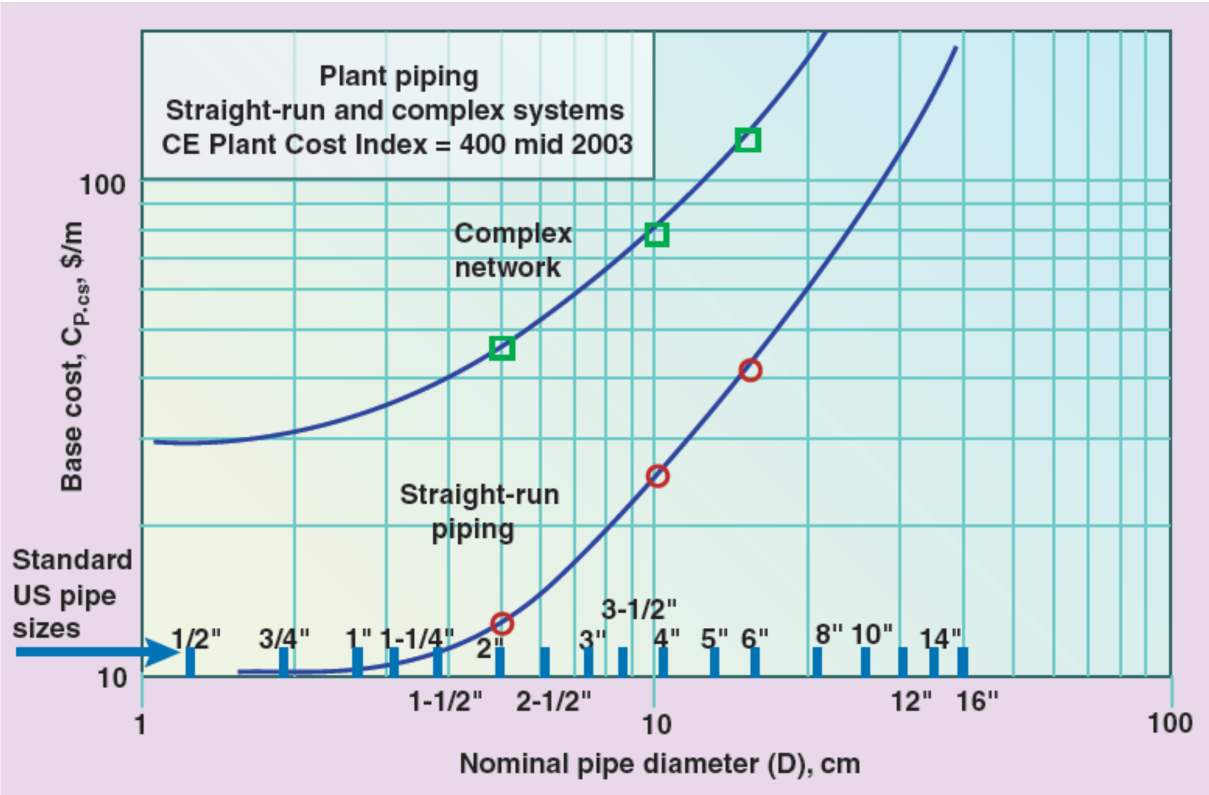

Figure 5 Pipe base cost ($C_{P,CS}$) based on pipe diameter (Ulrich & Vasudevan 2006).

2.1.5 Costs for fuel pipe for transferring combustible by-products from Perstorp to the Cracker

For the fuel pipe necessary to redistribute excess fuel by-products from Perstorp to Borealis a fixed cost based on data estimated from the cost of installing the existing gas pipe between the Borealis Cracker and PE plants. The existing line is an 8” gas pipe that runs 2000 m from the cracker to the PE plant. The pipe cost 20 MSEK to install, i.e. 10000 SEK/m. The distance from Perstorp to Cracker is approximately 4000 m, thus the cost of running a new fuel gas pipe line was estimated at 40 MSEK (Borealis AB 2010). This estimate was discussed with the plant experts and approved. For only the piping the estimate is relatively high according to the experts, but it this estimation was nevertheless retained in order to account for additional costs which arise when delivering by-product fuel from Perstorp to Borealis (changes to the boilers at Borealis, pumps/compressor depending on the state of the by-product fuel etc.).

2.1.6 Costs for HW pumps

Pump work is estimated at 2 % of the heat savings as estimated in the previous TSA II (Andersson et al. 2011) study for a system in which the maximum amount of heat is delivered. This estimate was also compared to previous studies performed by Borealis which came to a similar conclusion. Such an assumption is reasonable as the pump work necessary to circulate the HW is proportional to the mass flow of HW in the system which in return is proportional to the amount of heat delivered to the system. The flow conditions of the HW determined by the piping diameter and adjusted so pump work is kept at a reasonable value.

Pump investment costs are estimated with cost functions given by (Smith 2005). In order to account for potential pump failures it is assumed that 2 times as many pumps as the minimum necessary are installed.

Cost per pump unit in carbon steel operating at moderate pressure and Temperature:

A cost function similar to that presented in Eq. (8) is used to calculate cost for new pumps. The working fluid is HW at temperatures of max. 95 ºC and moderate pressure.

- According to (Smith 2005), the cost data factors for a centrifugal pump (large, including motor) are: C_B=9840 US$; K_B =4 kW (pump nominal power rating); M=0.55
- Max capacity: 700 kW, if more pump power is required an additional pump has to be installed.
- CEPCI for pumps and compressors (1.378) was used to update costs from 2000 (667.8) to 2012 (920.1) (CHE 2012).
- SEK/US$ = 6.4 (2013-02-22)

Fixed capital cost for one pump:

To calculate the fixed capital costs for one pump Eq. (9) is used. For f_M, f_T and f_P a factor of 1 is used since it can be assumed that no special material, temperature and pressure adjustments are needed. Other factors used to determine the fixed capital cost are given in Table 5.

2.1.7 Cost for compensation for heat losses

In order to compensate for heat losses more heat has to be supplied to the common heat recovery systems than the heat consumed by the process heat sinks. Therefore additional heat exchangers delivering heat have to be installed. After discussions with plant experts it is assumed that 10% of the heat consumed in the system is lost and has to be compensated for by installing additional heat exchangers. It is assumed that this heat will be supplied by the heat source with the lowest costs per unit of heat available in the suggested system.

2.2 Determining suitable combinations of heat recovery measures to achieve lowest overall systems costs

Based on the cost functions for the different system components (heat exchangers, piping, pumps) presented in 2.1 it is possible to estimate the total systems costs for a number of different common heat recovery systems. Figure 6 shows the algorithm applied in order to identify feasible and cost-effective heat recovery systems.

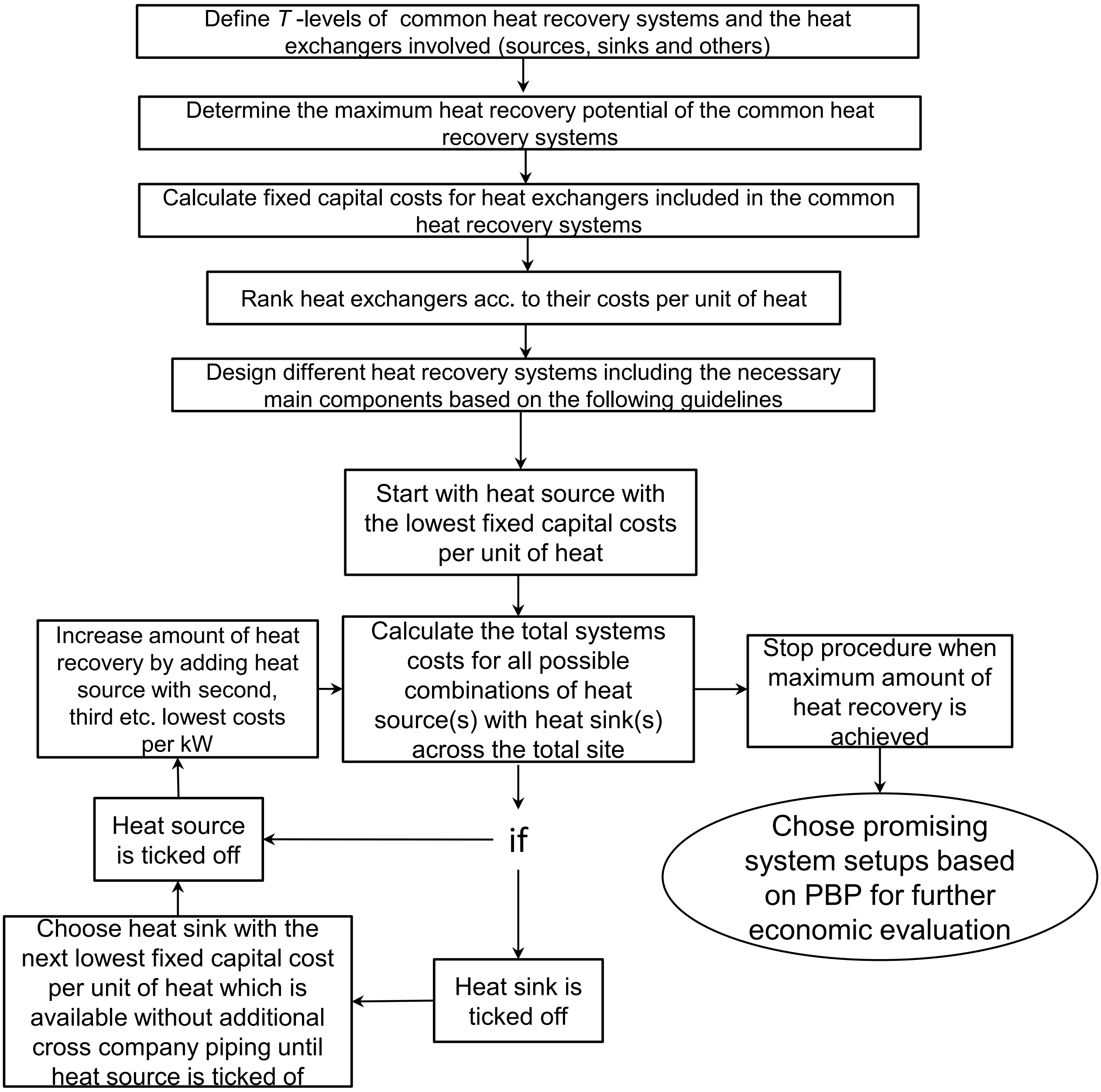

Figure 6 Illustration of the algorithm applied for identifying feasible and cost-effective common heat recovery systems.

As a first measure of cost-effectiveness simple PBP is used in order to screen the available combinations of site-wide heat recovery measures.

PBP is calculated according to Eq. (11):

$$PBP = \frac{initial\ Investment}{annual\ Cash\ Flow} \tag{11}$$

The Annual cash flow is calculated from the utility cost savings reduced by the operating costs, based on the following assumptions:

- Estimated revenues are based on the amount of heat delivered. It is assumed that all heat delivered will save boiler steam. Boiler steam is given a specific economic value of 400 SEK/MWh. These costs were determined after discussions with plant experts.

Costs are based on the price of natural gas and take into account the efficiency of the steam boilers (approx. 0.8). The authors are aware that natural gas prices are subject to major fluctuations. In this preliminary study this fact is addressed in a separate sensitivity analysis described in 2.4.

- Revenues from CW savings are assumed by estimating the amount of electricity savings by not having to pump CW. This is estimated to 0.025 $MW_{el}/MW_{CW\ saved}$[2].
- Operating costs are assumed as costs for maintenance and pump power:
    - Maintenance assumed as 2% of total fixed investment costs
    - Pump power assumed as 2% of heat transferred by the common heat recovery systems and costs for electricity, assumed at 600 SEK/MWh (in accordance with the plant energy experts)

As simple PBP assumes 100 % of the investment in the beginning of the project and that revenues are achieved from day one on, which is not realistic in heat recovery projects of this scale it is only suitable for a rough screening of different systems solutions. Simple PBP is widely used by companies for preliminary screening of projects (Sinnott & Towler 2009).

In order to provide detailed decision support other methods of evaluation (NPV, DCFROR) are used after the screening.

Main assumptions:

- The HW inlet and outlet temperature and heat exchangers identified in the TSA II study are retained (HW1: 79/55 °C, HW2: 95/75 °C).
- The total systems costs include all major investments necessary in order to enable for heat recovery consequently results in fuel savings in the cluster's boilers. A boiler efficiency of 0.8 is assumed.
- When possible the total amount of heat available from each source heat exchanger is delivered to the common heat recovery system. This is due to the high costs for constructing common infrastructure (piping between the plants, pumps, etc.). It is therefore most likely to be more advantageous to deliver as much heat as possible to the network once the costs for common infrastructure have been incurred.
- It is assumed that all heat that is delivered to the common heat recovery system is also used for process heating or for covering the HW network heat losses. If the amount of heat available in the HW system does not match the capacity of a full number of heat sinks, it is assumed that heat sinks are partially supplied with heat from the HW systems and the rest is supplied by the utility used today in order to reach the heat sinks target temperature.
- It is initially assumed that all excess steam made available by replacing steam with excess process heat is delivered to Perstorp. This is because Perstorp currently has the highest LP steam demand with approx. 25.7 MW, while at other plants like INEOS or Akzo Nobel the demand is currently limited to 2.5 MW and 0.3 MW, respectively.

Boundary conditions and limitations:

Saving steam at the cracker leads to an excess of LP steam. Currently LP steam is transferred from Borealis PE to Borealis Cracker. Therefore LP steam savings at the cracker ultimately result in excess LP steam at the PE site.

[2] Accounts for approximately the electricity needed for CW pumping (Hackl & Perret 2009).

In order to utilise excess LP steam the following options were identified:

- Transfer LP steam from the PE plant to Perstorp

Currently Perstorp has a demand of approx. 25.7 MW LP steam. Delivering more heat requires investment in new heat exchangers. Today Perstorp uses steam at higher temperature than necessary to heat certain process streams. Replacing these HX:s in order to use LP steam instead increases Perstorp's demand for LP steam. Maximum LP steam demand at Perstorp is limited to approx. 40.3 MW due to process requirements.

- Transfer LP steam from the cracker to INEOS

INEOS current demand of LP steam is approx. 2.5 MW and can be increased to approx. 10.5 MW.

- Transfer LP steam from the cracker to Akzo Nobel

Akzo Nobel's current demand of LP steam is approx. 0.3 MW and can be increased to approx. 2.8 MW.

Delivering LP steam to Perstorp leads to an excess of combustible by-products. Currently Perstorp uses combustible by-products from their processes to generate steam in their boilers for process heating. If steam from Perstorp's boilers is replaced by LP steam from another plant at a certain stage, combustion of by-products will no longer be necessary. This is valid if delivery of steam to Perstorp exceeds 23.8 MW. Additional investment in a fuel pipe to Borealis Cracker is needed to realise further savings. The cracker boilers can combust the by-products after minor adjustments. Here they can be used to co-generate steam to cover the process heat demand and generate power to drive compressors and a generator.

2.3 Evaluation of the different solutions:

A number of systems solutions are identified and compared according to their NPV and DCFROR.

2.3.1 Net Present Value (NPV)

According to Sinnot and Towler (Sinnott & Towler 2009) NPV is a more useful economic measure than simple PBP. It allows for annual variation in expenses and revenues and for the time value of money. This is advantageous as larger projects, like implementing common heat recovery systems, are not completed in a single year. In this case it is assumed that 50 % of the total fixed capital is invested in the first year of the project and no incomes are generated in this year, i.e. $CF_0 = -{Inv_{\cos t}}/{2}$. The rest of the total fixed capital is invested in the second year of the project and the full production capacity is achieved,

i.e. $CF_1 = -{Inv_{\cos t}}/{2} - Operation_{\cos t} + Income_{fuel/CW\,savings}$.

The NPV is calculated according to Eq. (12):

$$NPV = \sum_{n=1}^{n=t} \frac{CF_n}{(1+i)^n} \tag{12}$$

where,

CF_n = Cash flow in year n

t =project life in year

i =interest rate (cost of capital)

In this case a project life time and interest rate of 15 years and 11 % are assumed. These values were determined based on discussions with the company representatives and are typical for strategic energy efficiency investments. Thus, the $NPV_{15,}$ the NPV over a 15-year period is determined.

2.3.2 Discounted Cash-Flow Rate of Return (DCFROR)

The DCFROR is the interest rate at which the cumulative NPV at the end of the project is zero. In other words it is the maximum interest rate the project can pay and still break even at the end of the project's life time. The higher the DCFROR the more profitable is the project. Companies usually expect a DCFROR larger than the cost of capital (=interest rate).

Calculating the DCFROR enables comparing different project independently of the amount of capital used. This is especially interesting in the given case, as the different heat recovery systems involve strongly differing levels of capital investment. (Sinnott & Towler 2009)

2.4 Sensitivity Analysis

During this analysis and discussions with the plant experts several parameters were identified of having large uncertainties. A sensitivity analysis of critical parameters is performed. The following parameters are varied and their influence on PBP and DCFROR of the two selected heat recovery system are determined.

- **Value of steam/natural gas**: The costs for natural gas are a matter of large uncertainty. In order to give an understanding of the sensitivity of the economic indicators to fluctuations of the price of fuel the cost of steam is varied by +/- 30 %.
- **HX cost:** HX cost calculations are performed according to literature data which usually is used for project cost calculations with an accuracy of +/- 30 %. The HX costs are varied within this range. Also HX are assumed of shell and tube type and estimated larger than necessary. In some cases plate HX might be applicable and lower area might be sufficient. This decreases capital costs.
- **Piping cost**
    - HW piping: In the base case calculations a relatively high cost for district heating piping was assumed ("Stadsmiljö"). Cost data for "Ytterområde" and "Parkmark" which are lower are available as well. The exact path of how the HW piping would be constructed between the plants is not known. In order to give an understanding of how PBP and DCFROR of the systems are influenced by the path of the HW pipes the alternative cost data is used for HW piping calculations in this sensitivity analysis.
    - Steam piping: Steam piping cost calculations are performed according to literature data which usually is used for project cost calculations with an accuracy of +/- 30 %. The steam piping costs are varied within this range. During discussions with energy experts at the companies in Stenungsund large uncertainties concerning the cost of steam piping were identified. Therefore an additional case where investment costs of three times the estimated base costs (+ 200%) are assumed was calculated.

    - Fuel piping: Fuel piping costs were varied with +/- 30 % of the base cost. The base cost assumed for this parameter is deemed to be somewhat high, but transferring by-product fuel to another boiler makes certain adjustments to the boiler necessary, which is why a high cost scenario is assumed in this analysis.
- **Large investment cost uncertainty scenario:** Total investment cost calculations are performed according to literature data which usually is used for project cost calculations with an accuracy of +/- 30 %. In this scenario a 30 % variation of the total investment costs is assumed.

3 Results and Discussion

In the following the results for a number of common heat recovery systems are shown. The results are summarised in Figure 7, which shows the estimated PBP and total fixed capital of different heat recovery systems depending on the amount of heat recovered.

In section 3.2 some promising options are compared using NPV and DCFROR to give a more representative indication of the profitability of the different solutions presented.

In section 3.3 a detailed description of two promising complementary heat recovery system identified is given.

3.1 PBP and total fixed capital for different heat recovery systems

Figure 7 shows the consequences of increasing the amount of heat recovery on the overall PBP and total fixed capital of the investments.

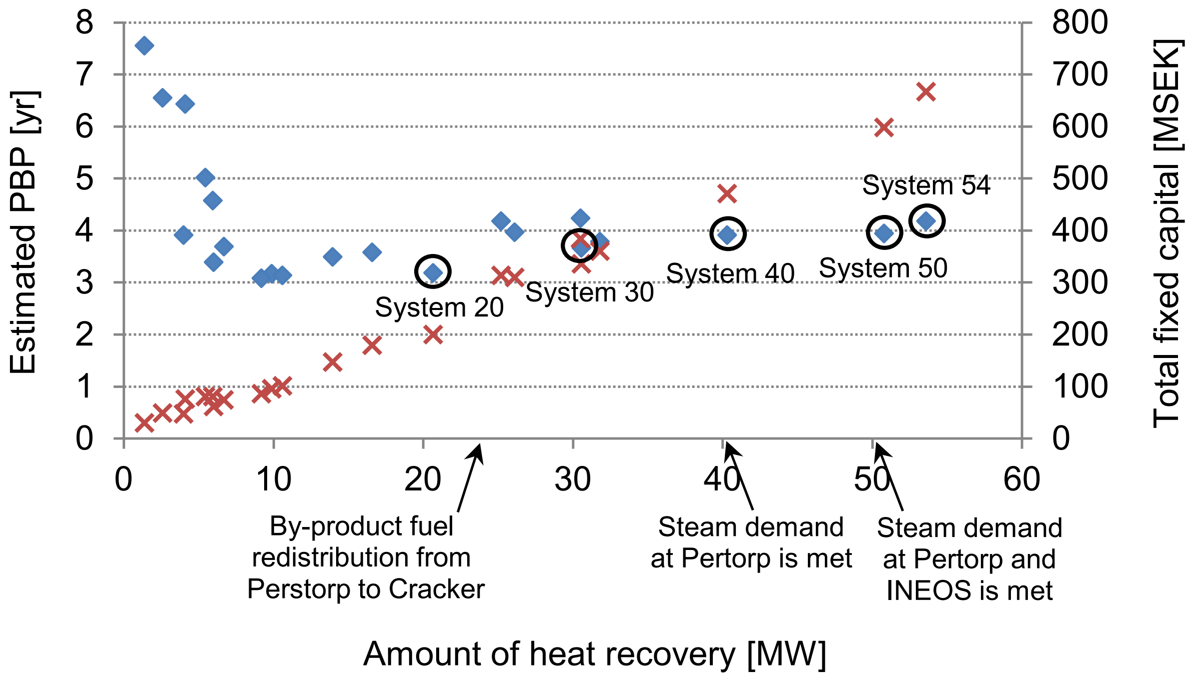

Figure 7 Illustration of the consequences of increased heat recovery with the HW systems on the overall PBP; red crosses: Total fixed capital, blue diamonds: PBP.

It is shown that the total fixed capital increases steadily with the amount of heat recovery. The PBP drops rapidly from approx. 7.6 to around 3.2 years when increasing the amount of heat recovery from 1.4 to 20.7 MW. This is due to the large infrastructure investments necessary, namely HW and steam piping between the plants. It is shown that once those investments are included, the PBP is rather stable when the amount of heat recovery is increased further.

A sudden increase in PBP can be observed just above 20 MW of heat recovery. This is because above 23.8 MW of heat recovery, investments in among others a fuel pipe between Borealis Cracker and Perstorp (see label below the figure) are required which strongly influences the results.

Thereafter the estimated PBP is relatively constant at around 4 years. It is at the lowest at a recovery of 30.6 MW of heat with a value of 3.7 year. After that it increases slightly up to 4.2 years for recovery of 53.8 MW of heat. This increase in PBP can be explained by the increased complexity of the systems. Once a certain threshold of heat recovery is reached more complex changes are necessary in order to further increase overall recovery and utilization of excess heat. E.g. recovery of more than 25.7 MW up to 40.3 MW of heat demands that heat exchangers at Perstorp currently using MP or HP steam have to be converted to use of LP steam in order to increase the demand for excess LP steam. Above 40.3 MW heat recovered an additional steam pipe between the Cracker and INEOS (see label below the figure) has to be constructed as Perstorps possibilities to use LP steam become saturated. Above 42.8 MW of heat recovery, heat exchangers at INEOS have to be converted to use LP steam to increase the excess LP steam consumption. Above 50.8 MW of heat recovery a steam pipe between Borealis Cracker and Akzo Nobel (see label below the figure) is necessary to further increase heat recovery to 53.8 MW. As the PBP for this system recovering 53.8 MW increases further expansion of the system will always lead to less profitable systems solutions. This is discussed further in the next section.

A number of promising heat recovery systems called System 20, System 30, System 40, System 50 and System 54 are marked with black circles in Figure 7. The system's numbering reflects the amount of heat recovered.()The systems are investigated in more detail using more advanced indicators, namely NPV and DCFROR. The results of this analysis are presented in the following

3.2 Comparison of the selected systems using NPV and DCFROR

The results of NPV and DCFROR calculations for selected systems configurations are given in Figure 8.

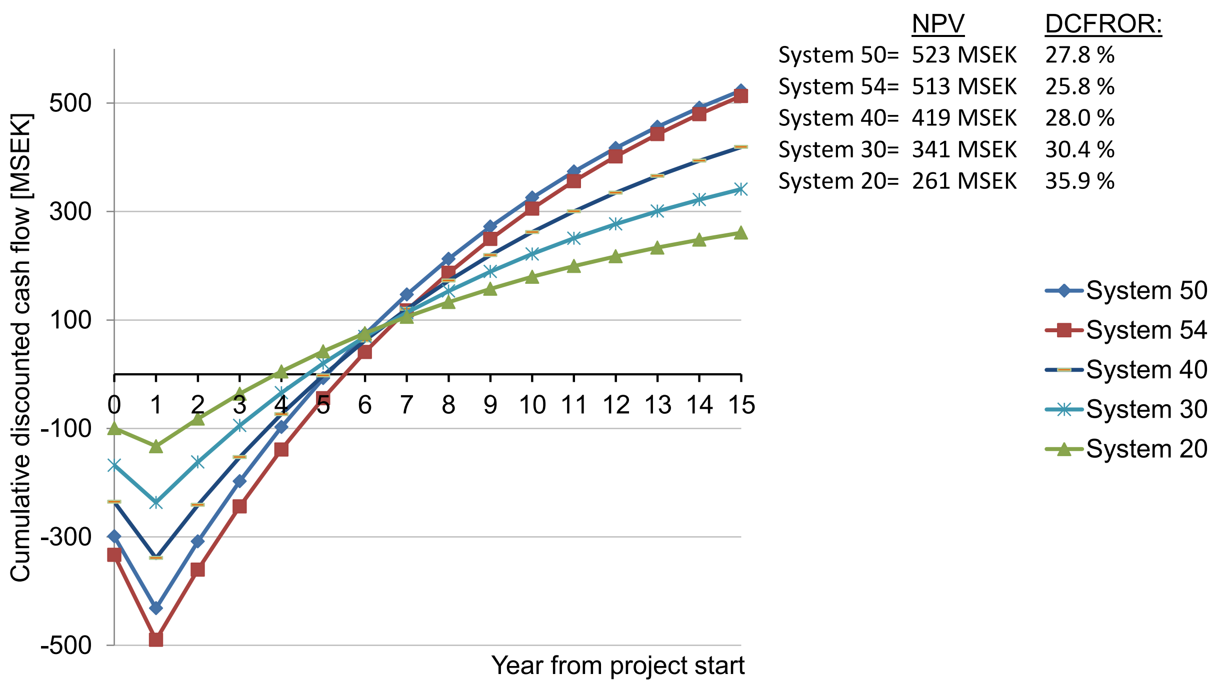

Figure 8 Cash flow diagram accounting for the time value of money. NPV_{15} and DCFROR of each system are presented to the right.

The 5 cases analysed where chosen due to their low PBP found in the previous analysis. PBP is primarily a measure of risk and doesn't allow for further insight on the economic performance of an investment. Figure 8 shows the NPV_{15} of the 5 identified cases. In the beginning of the projects the graphs go downwards. This is due to the investments taken in the beginning of the project and the assumption that no income is generated in the first year. After that the projects start generating income and the graphs go upward. All systems have a positive NPV at the end of the project life time (15 years). System 50 generates the highest NPV at the end of its life time. This is mainly due to its larger size, compared to e.g. System 40, 30 and 20. System 54 generates a lower NPV even though it is larger than System 50 and therefore System 54's economic performance is inferior to System 50.

Comparison of System 50 with System 40, 30 and 20 on the basis of NPV does not show the whole picture. Therefore DCFROR was calculated to assess the performance of capital for the different projects. As shown in Figure 8 System 20 achieves the largest DCFROR of 35.9 % meaning that based on the invested capital System 20 is the most profitable option. The other systems show comparable results for DCFROR, ranging from 25.8 % (System 54) to 30.4 % (System 30).

The superior DCFROR and PBP performance of System 20 is due to the fact that in this case it is not necessary to invest in a fuel pipe (and boiler adjustments) between Borealis Cracker and Perstorp, which leads to large investment cost savings. As this solution is far from achieving the full heat recovery potential of the cluster it should be considered as a first step, a "low hanging fruit" towards a more advanced solution, which enables for increased heat recovery. Exactly how much better the economic performance of System 20 is compared to the other systems strongly depends on the cost of the fuel pipe. In this study a rather rough cost estimate is used for the fuel pipe, as the exact adjustments necessary to deliver and utilise by-product fuel from Perstorp at Borealis Cracker are relatively uncertain.

As a final step of this development System 50 is suggested, as it was shown to result in the highest NPV. In this case System 20 has to be adjusted in order to enable for further extension. HW and steam pipes have to be sized accordingly in order to be able to use them also in an extended system to transfer the future amount of HW and steam.

Based on the economic results and in order to give further insight on how a future common heat recovery system in Stenungsund could look like the System 20 and System 50 configurations are described in detail in the following.

3.3 Detailed description of promising systems

3.3.1 System 20

Figure 9 illustrates System 20 with all HX numbers and piping necessary for the retrofit. The heat recovery system consists of HW1 (79/55 °C). Only two companies (Borealis and Perstorp) are involved in the retrofit. Perstorp acts solely as a sink for LP steam and does not participate in other heat recovery measures. No changes to Perstorp's HX system are required. In total 5 new HX:s are required. Heat from three HX:s at Borealis PE is transferred to HW1 and then transported for delivery to two HX:s at the Cracker. The excess of LP steam created by replacing LP steam with HW at the Cracker plant is transferred to Perstorp.

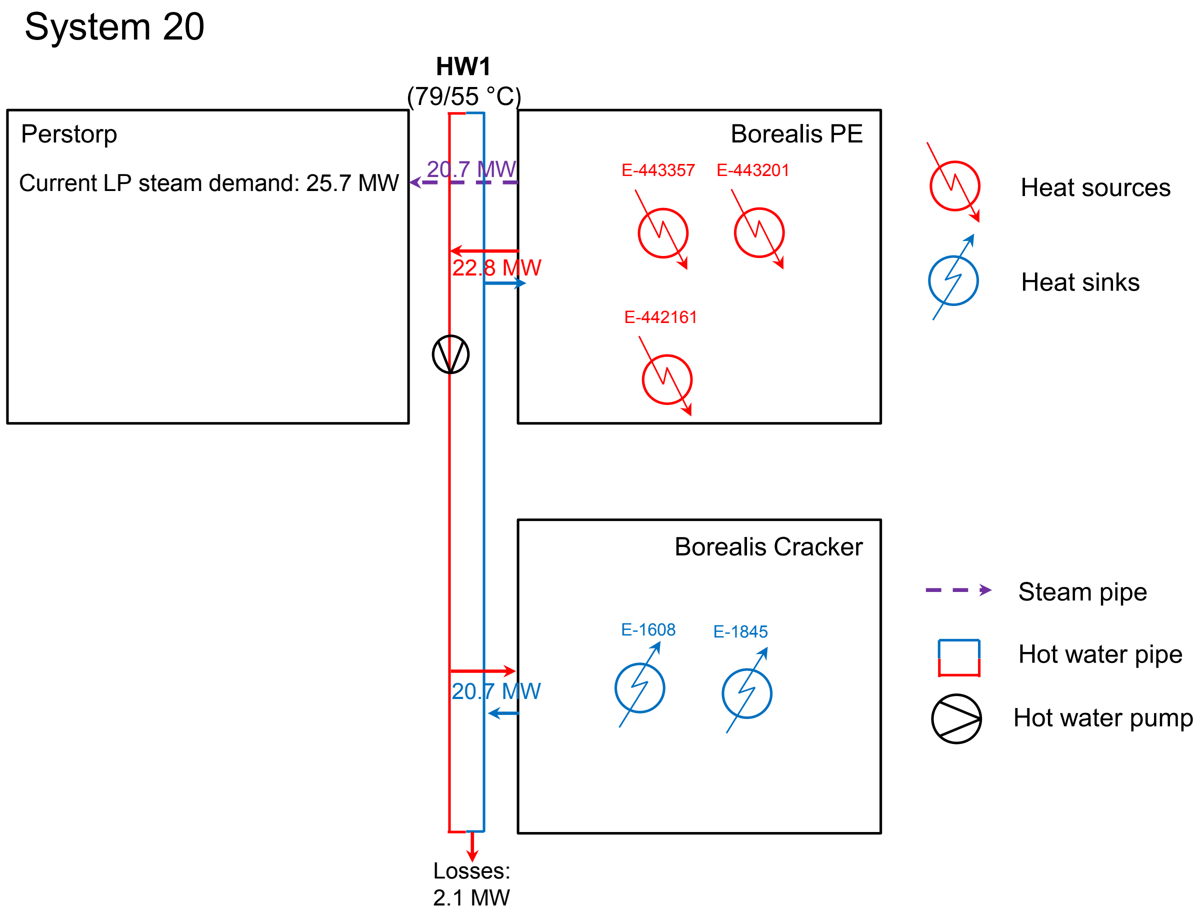

Figure 9 Illustration of a common heat recovery system (System 20) showing HX:s delivering and receiving heat from the HW circuit (79/55 °C) and steam pipes for redistribution of excess steam

Total fixed capital:

Table 8 Summary of the estimated investment cost for implementing System 20.

Cost item	MSEK	Percentage of total fixed capital	Additional cost for allowing expansion
HX heat supply	87	44	5[1]
HX heat consumers	32	16	5
HX heat loss compensation	19	9	
HW piping	30	15	13
Steam/condensate piping	23	11	16
Fuel pipe	na	na	
HW pumps	9	4	2
Total fixed capital	**199**		**41**[2]

[1] Includes increased costs for HX:s installed to compensate for heat losses
[2]Additional cost of increased HX-areas and size of HW and steam pipes to in the future transfer larger quantities of heat

By far the largest investments are HXs delivering heat from Borealis PE. Other major investments are necessary at Borealis Cracker to be able to receive heat from the HW system and the HW piping. To the right in Table 10 the additional investment costs for preparing System 20 for expansion towards System 50 are shown. The exact measures causing the “additional cost for allowing expansion” are:

- Larger HX-area of E-442161 in order to deliver 24 MW heat from PE to the HW1 system. In System 20 Borealis PE delivers 22.8 MW of heat to HW1.
- Larger HX-area of E-1845 in order to prepare for increased consumption of recovered process heat.
- Wider diameter of the HW pipes as in a future expanded heat recovery system more heat is transferred between Borealis PE and the cracker.
- Larger HW pumps to enable for transferring more HW between Borealis PE and the cracker.
- Wider diameter of the steam/condensate pipes between Borealis PE and Perstorp as increased heat recovery by HW results in an increased amount of excess LP steam.

Revenues and operating costs:

Table 9 Estimated revenues from steam and CW savings and operating costs

Revenues and Operating costs	MW	MSEK/yr*
Steam savings	20.7	66
CW savings	0.5 (electricity)	2.5
Operating costs (Maintenance + pump power)		6

* Assumed operating hours: 8000 h/yr

All process heat recovered at the PE plant is transferred to the Cracker plant to replace LP steam. As the LP steam demand at this site is already met and the boiler capacity cannot be reduced any further. Therefore 20.7 MW of steam are sent to Perstorp where it replaces fuel in the boilers. Fuel savings at Perstorp by steam from Borealis are estimated to approx. 26 MW.

3.3.2 System 50

Figure 10 illustrates the selected System 50. The heat recovery system consists of two HW circuits, HW1 and HW2. Three companies (Borealis, Perstorp and INEOS) are involved in the retrofit, while INEOS only receives LP steam and does not participate in other heat recovery measures. In total 32 new HX:s are required. Heat from three HX:s at Borealis PE and one HX from Borealis Cracker is delivered to HW1 and transferred to three HX:s at the Cracker. HW2 receives heat from six HX:s at Perstorp's site and supplies it to one HX at Perstorp's own site and five at the Cracker plant. Thus most of the steam savings occur at the Cracker plant, leading to an excess of LP steam. Excess steam must be transferred to Perstorp and INEOS and at the same time HX:s at this sites have to be adjusted to be able to utilize LP steam. At Perstorp 9 HX:s have to be rebuilt to increase the demand for LP steam to 40.3 MW. At INEOS 4 HX have to be constructed in order to increase the demand for LP steam to 10.5 MW.

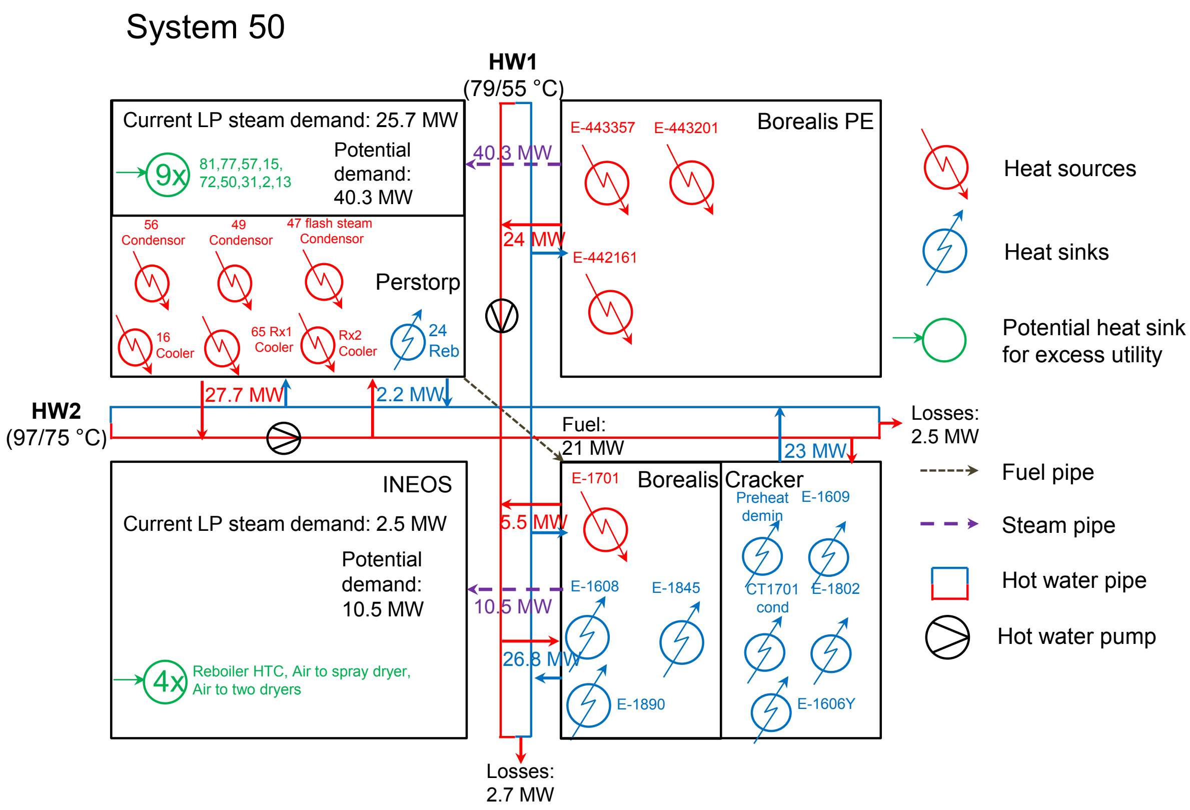

Figure 10 Illustration of a common heat recovery system (System 50) showing HX:s delivering and receiving heat from the common HW circuits, HW1 (79/55 °C) and HW2 (97/75 °C), steam and fuel pipes for **redistribution of excess utilities and HX:s that must be adjusted for increasing LP steam demand**

All number or descriptions of HX:s concerned by the suggested changes are defined in Figure 10.
Comparing this system with System 20 it can be seen that HW1 (79/55 °C) in System 50 has to transfer a larger amount of heat (29.5 MW instead of 22.8 MW) and also the steam pipe from Borealis PE to Perstorp transfers more heat (40.3 MW instead of 20.7 MW). These differences need to be taken into account if System 20 should be increased towards System 50 in order to avoid extra costs for additional piping.

Total fixed capital:

Table 10 shows the total fixed capital of all components of System 50.

Table 10 Summary of the estimated investment cost for implementing the System 50.

Cost item	MSEK	Percentage of total fixed capital
HX heat supply	227	38
HX heat consumers	97	16
HX LP steam adjustments	21	3
HX heat loss compensation	39	7
HW piping	107	18
Steam/condensate piping	48	8
Fuel pipe	40	7
HW pumps	20	3
Total fixed capital	**598**	

It can be seen that HX:s supplying heat to the HW systems stand for the largest share of the total fixed capital. Other major cost contributors are the heat consumers and HW piping between the plants.

<u>Revenues and operating costs:</u>

Table 11 shows steam, CW savings and operating costs of System 50.

Table 11 Estimated revenues from steam and CW savings and operating costs

Revenues and Operating costs	MW	MSEK/yr*
Steam savings	50.8	163
CW savings	1.3 (electricity)	6
Operating costs (Maintenance + pump power)		17

* Assumed operating hours: 8000 h/yr

Due to the complex structure of the system the steam savings do not occur in one boiler. Most of the process heat recovered is used at the Cracker plant, but as the LP steam demand at this site is already met and the boiler capacity cannot be reduced any further 40.3 MW of steam are sent to Perstorp where it replaces fuel in the boilers. Perstorp has some combustible by-products which currently are used as boiler fuel to produce steam. Delivering steam to Perstorp enables for approx. 30 MW[3] of fuel savings. 21 MW of by-product fuel have to be exported to Borealis Cracker for combustion, where it replaces fuel gas in the boilers. In addition, 10.5 MW of LP steam have to be exported from the Cracker to INEOS were it replaces approx. 13 MW[4] of fuel.

Table 12 Summary of steam and corresponding fuel savings (or opposite) and the savings allocation

Plant	Steam savings [MW]	Fuel savings [MW]
Borealis Cracker	16.8	21
Perstorp	24	30
INEOS	10	13
Total savings	50.8	64

Table 12 summarizes the steam and related fuel savings at the different companies. Savings at Borealis are due to by-product fuel received from Perstorp which means that Borealis does not have to use their fuel gas and can utilise it otherwise. Perstorp avoids importing fuel for process steam generation due to steam delivery from Borealis. The same happens at INEOS.

System 50 is shown to be more profitable based on PBP, NPV and DCFROR than systems recovering a larger amount of heat, like System 54, which is why it can be considered at the conditions assumed in this study as the final step in the development of common heat recovery systems in Stenungsund. Increasing fuel prices can change this situation so investments in even more heat recovery become feasible.

3.4 Sensitivity analysis of important parameters

Sensitivity analysis of several important parameters influencing economic performance of the two selected energy recovery systems (System 20 and System 50) was performed. The results are presented in Table 13. The results obtained in the base case analysis for each system are given as well. To the right in Table 13 the results of a sensitivity analysis assuming an increase

[3] 23.8 MW of steam delivered replace 30 MW fuel considering a boiler efficiency of 0.8
[4] Assuming a boiler efficiency of 0.8

in steam/condensate piping costs of + 200 % are shown. This case is investigated due to large practical uncertainties in the design of steam/condensate piping across different plants.

Table 13 Summary of sensitivity analysis on important parameters and their influence on PBP and DCFROR: Value of steam/natural gas, HX investment and piping cost

	+: high price/cost scenario		-: low price/cost scenario		alternative case + 200%*	
System 20 **Base case: PBP=3.2 yr; DCFROR=35.9 %**	PBP	DCFROR	PBP	DCFROR	PBP	DCFROR
Value of steam/natural gas (**+/-** 30 %)	2.4	49.5 %	4.7	22.5 %		
HX inv. cost (**+/-** 30 %)	3.9	28.2 %	2.5	47.8 %		
Steam/condensate piping cost (**+/-** 30 %); **+ 200 %**	3.3	34.4 %	3.1	37.6 %	3.6	27.7 %
HW piping cost (**+**:"Ytterområde) -:"Parkmark")	3.1	37.1 %	3.0	38.5 %		
Fuel piping (**+/-** 30 %)	na	na	na	na		
Total investment cost (+/- 30 %)	4.2	26.2 %	2.2	54.4 %		
System 50 **Base case: PBP= 3.9 yr; DCFROR=26.6 %**						
Value of steam/natural gas (**+/-** 30 %)	3.0	38.7 %	5.8	16.7 %		
HX cost (**+/-** 30 %)	4.8	21.8 %	3.1	36.5 %		
Steam/condensate piping cost (**+** 30 %/- 30 %); **+ 200 %**	4.0	26.9 %	3.8	28.6 %	4.6	22.7%
HW piping cost (**+**:"Ytterområde)/ -:"Parkmark")	3.8	28.9 %	3.7	30.2 %		
Fuel piping cost (**+/-** 30 %)	4.0	27.0 %	3.9	28.5 %		
Total investment cost (+/- 30 %)	5.2	19.9 %	2.7	42.4 %		

*Estimated base cost for steam/condensate piping for System 20: 22.7 MSEK; System 50: 47.7 MSEK
Alternative case(+ 200 %) estimated steam/condensate piping cost for System 20: 68.1 MSEK; System 50: 143.1 MSEK.

For System 20, the PBP and DCFROR for all investigated cases is below 5 years and above 20 %.

It can be seen that PBP only exceeds 5 years in case of a 30 % decrease in fuel price and an increase in total investment costs and only in this case DCFROR drops below 20 % for System 50. In all other investigated cases PBP and DCFROR are below 5 years and above 20 %, respectively. Even in the case where costs for steam/condensate piping are assumed to be three times (+ 200 %) higher than the base case value the estimated PBP stays below 5 years (4.6) and a DCFROR of 22.7 % is achieved for System 50.

The economic performance is most sensitive to fluctuations of the value of steam. Another parameter that strongly influences the economic performance is the cost of HX:s. This is due to their large share considering the total fixed capital of the heat recovery systems.

In this analysis only one parameter is varied at a time. In practice this of course is not necessarily the case, but still by doing so some indication on the robustness of the economic performance can be obtained. In general it can be seen that varying the parameters shown in this analysis does show that the economic performance of the heat recovery systems identified is relatively robust and that economically feasible solutions have been identified.

HX costs also show to have a large impact on PBP and DCFROR. HX costs can be lower due to potential use of plate HX instead of shell and tube as assumed in this study. Also the estimated size in this study was increased by 25 %, which might not be necessary in all cases.

4 Conclusions and Recommendations

In this work results from two previous studies were used to identify cost efficient common heat recovery measures in the chemical cluster in Stenungsund. During previous studies technically feasible energy efficiency measures were identified. A methodology to identify the most economically favourable measures was not introduced.

In the presented work a **methodology to identify cost efficient measures** is presented. First all the different cost items of such common heat recovery measures are identified. Thereafter an engineering approach to estimate all the different costs (HX, piping, pumps etc.) involved is presented. A methodological approach to identify cost-efficient common heat recovery systems is then introduced. After this screening some promising systems are evaluated in more detail.

According to the results of the Total Site Analysis of the chemical cluster in Stenungsund, the theoretical potential for heat savings that can be accomplished by common site-wide heat recovery measures is 122 MW. During this study several promising systems were identified recovering between approx. 20 MW and 54 MW of heat and thereby savings up to approx. 67 MW of fuel in the clusters boilers. Two systems are presented in more detail. One system recovering 20.6 MW of heat (**System 20**) by transferring excess heat from Borealis PE to Borealis Cracker and delivering excess LP steam to Perstorp. This system only **involves two of the companies** located in the cluster. 5 new HXs have to be installed, a HW circuit (79/55 °C) operating between Borealis PE and Borealis cracker and a steam pipe between Borealis PE and Perstorp. This solution is the **most profitable** with a PBP of 3.2 years and a DCFROR of 35.9 %. But also has the lowest NPV_{15} of the promising systems identified. This is because it only utilizes a small part of the total heat integration potential. It is therefore considered as a first step prior to further heat integration.

As a **final step** in this development a system recovering 50.8 MW (**System 50**) is presented. The system is more complex needing 32 new HX:s, two HW circuits (HW1: 79/55 °C, HW2: 97/75 °C) between Borealis PE and Borealis Cracker and Perstorp and Borealis Cracker. Steam also has to be transferred from Borealis PE to Perstorp and beyond that from Borealis Cracker to INEOS. Three companies (Borealis, Perstorp and INEOS) are involved in the system, INEOS only as a recipient of excess LP steam. The system was shown to be more profitable based on PBP, NPV and DCFROR than systems recovering a larger amount of heat and is therefore seen as the final step in the development of a common heat recovery system in Stenungsund.

The system that achieves the most heat recovery with only **two companies (Borealis and Perstorp)** involved and therefore is considered “the simplest” from a company participation point of view can recover 40.3 MW (System 40). The system is described in the Appendix.

One important observation is that the PBP of common heat recovery system configurations increases rapidly if it is necessary to redistribute LP utility steam between the plants. Therefore for future studies it is **very important** to thoroughly investigate opportunities to use as much utility as possible at one site, e.g. **investigate the opportunity to increase the LP steam demand at Perstorp even further** in order to avoid expensive construction of steam piping to INEOS and/or Akzo Nobel and at the same time enable for increased recovery of heat.

Sensitivity analysis of important economic assumptions and estimates showed that System 20 and System 50 are **relatively robust** to variations in revenues and investments costs. Revenues from steam savings, HX, piping and total investments costs are varied with +/- 30 %. Results show that only in two cases (30 % decrease in revenues from steam savings and 30 % increase in total investment costs) the PBP and DCFROR of System 50 exceeds 5 years and drops below 20 % respectively. Even in an alternative case where steam piping costs are assumed to increase by 200 % PBP and DCFROR are 3.6 years and 27.7 % for System 20 and 4.6 years and 22.7 % for System 50.

HX cost showed a large impact on the PBP and DCFROR. Cost reduction can be expected due to potential use of plate HX and the relatively large size increase assumed in this study.

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APPENDIX

APPENDIX 1

Table 14 List of nominal piping diameters (Engineering ToolBox 2013; Engineersedge 2013)

NPS	DN	OD [in (mm)]	Wall thickness [in (mm)]							
			SCH 5	SCH 10s/10	SCH 30	SCH 40s/40 /STD	SCH 80s/80 /XS	SCH 200	SCH 300	XXS
⅛	6	0.405 (10.29)	0.035 (0.889)	0.049 (1.245)	0.057 (1.448)	0.068 (1.727)	0.095 (2.413)	—	—	—
¼	8	0.540 (13.72)	0.049 (1.245)	0.065 (1.651)	0.073 (1.854)	0.088 (2.235)	0.119 (3.023)	—	—	—
⅜	10	0.675 (17.15)	0.049 (1.245)	0.065 (1.651)	0.073 (1.854)	0.091 (2.311)	0.126 (3.200)	—	—	—
½	15	0.840 (21.34)	0.065 (1.651)	0.083 (2.108)	0.095 (2.413)	0.109 (2.769)	0.147 (3.734)	—	0.188 (4.775)	0.294 (7.468)
¾	20	1.050 (26.67)	0.065 (1.651)	0.083 (2.108)	0.095 (2.413)	0.113 (2.870)	0.154 (3.912)	—	0.219 (5.563)	0.308 (7.823)
1	25	1.315 (33.40)	0.065 (1.651)	0.109 (2.769)	0.114 (2.896)	0.133 (3.378)	0.179 (4.547)	—	0.250 (6.350)	0.358 (9.093)
1¼	32	1.660 (42.16)	0.065 (1.651)	0.109 (2.769)	0.117 (2.972)	0.140 (3.556)	0.191 (4.851)	—	0.250 (6.350)	0.382 (9.703)
1½	40	1.900 (48.26)	0.065 (1.651)	0.109 (2.769)	0.125 (3.175)	0.145 (3.683)	0.200 (5.080)	—	0.281 (7.137)	0.400 (10.160)
2	50	2.375 (60.33)	0.065 (1.651)	0.109 (2.769)	0.125 (3.175)	0.154 (3.912)	0.218 (5.537)	0.250 (6.350)	0.343 (8.712)	0.436 (11.074)
2½	65	2.875 (73.03)	0.083 (2.108)	0.120 (3.048)	0.188 (4.775)	0.203 (5.156)	0.276 (7.010)	0.300 (7.620)	0.375 (9.525)	0.552 (14.021)
3	80	3.500 (88.90)	0.083 (2.108)	0.120 (3.048)	0.188 (4.775)	0.216 (5.486)	0.300 (7.620)	0.350 (8.890)	0.438 (11.125)	0.600 (15.240)
3½	90	4.000 (101.60)	0.083 (2.108)	0.120 (3.048)	0.188 (4.775)	0.226 (5.740)	0.318 (8.077)	—	—	0.636 (16.154)

NPS 4 to NPS 9

NPS	DN	OD [in (mm)]	Wall thickness [in (mm)]										
			SCH 5	SCH 10s/10	SCH 20	SCH 30	SCH 40s/40 /STD	SCH 60	SCH 80s/80 /XS	SCH 100	SCH 120	SCH 140	SCH 160	XXS
4	100	4.500	0.083	0.120	—	0.188	0.237	0.281	0.337	—	0.437	—	0.531	0.674

		(114.30)	(2.108)	(3.048)		(4.775)	(6.020)	(7.137)	(8.560)		(11.100)		(13.487)	(17.120)
4½	**115**	5.000 (127.00)	—	—	—	—	0.247 (6.274)	—	0.355 (9.017)	—	—	—	—	0.710 (18.034)
5	**125**	5.563 (141.30)	0.109 (2.769)	0.134 (3.404)	—	—	0.258 (6.553)	—	0.375 (9.525)	—	0.500 (12.700)	—	0.625 (15.875)	0.750 (19.050)
6	**150**	6.625 (168.28)	0.109 (2.769)	0.134 (3.404)	—	—	0.280 (7.112)	—	0.432 (10.973)	—	0.562 (14.275)	—	0.719 (18.263)	0.864 (21.946)
7	**—**	7.625 (193.68)	—	—	—	—	0.301 (7.645)	—	0.500 (12.700)	—	—	—	—	0.875 (22.225)
8	**200**	8.625 (219.08)	0.109 (2.769)	0.148 (3.759)	0.250 (6.350)	0.277 (7.036)	0.322 (8.179)	0.406 (10.312)	0.500 (12.700)	0.593 (15.062)	0.719 (18.263)	0.812 (20.625)	0.906 (23.012)	0.875 (22.225)
9	**—**	9.625 (244.48)	—	—	—	—	0.342 (8.687)	—	0.500 (12.700)	—	—	—	—	—

NPS 10 to NPS 24

NPS	**DN**	**OD [in (mm)]**	**Wall thickness [in (mm)]**						
			SCH 5s	**SCH 5**	**SCH 10s**	**SCH 10**	**SCH 20**	**SCH 30**	**SCH 40s/STD**
10	**250**	10.75 (273.05)	0.134 (3.404)	0.134 (3.404)	0.165 (4.191)	0.165 (4.191)	0.250 (6.350)	0.307 (7.798)	0.365 (9.271)
12	**300**	12.75 (323.85)	0.156 (3.962)	0.165 (4.191)	0.180 (4.572)	0.180 (4.572)	0.250 (6.350)	0.330 (8.382)	0.375 (9.525)
14	**350**	14.00 (355.60)	0.156 (3.962)	0.156 (3.962)	0.188 (4.775)	0.250 (6.350)	0.312 (7.925)	0.375 (9.525)	0.375 (9.525)
16	**400**	16.00 (406.40)	0.165 (4.191)	0.165 (4.191)	0.188 (4.775)	0.250 (6.350)	0.312 (7.925)	0.375 (9.525)	0.375 (9.525)
18	**450**	18.00 (457.20)	0.165 (4.191)	0.165 (4.191)	0.188 (4.775)	0.250 (6.350)	0.312 (7.925)	0.437 (11.100)	0.375 (9.525)
20	**500**	20.00 (508.00)	0.188 (4.775)	0.188 (4.775)	0.218 (5.537)	0.250 (6.350)	0.375 (9.525)	0.500 (12.700)	0.375 (9.525)
22	**550**	22.00 (558.80)	0.188 (4.775)	0.188 (4.775)	0.218 (5.537)	0.250 (6.350)	0.375 (9.525)	0.500 (12.700)	0.375 (9.525)
24	**600**	24.00 (609.60)	0.218 (5.537)	0.218 (5.537)	0.250 (6.350)	0.250 (6.350)	0.375 (9.525)	0.562 (14.275)	0.375 (9.525)
28	**700**	28.000 (711.200)	—		-	0.312 (7.925)	0.500 (12.700)	0.625 (15.875)	0.375 (9.525)

APPENDIX 2

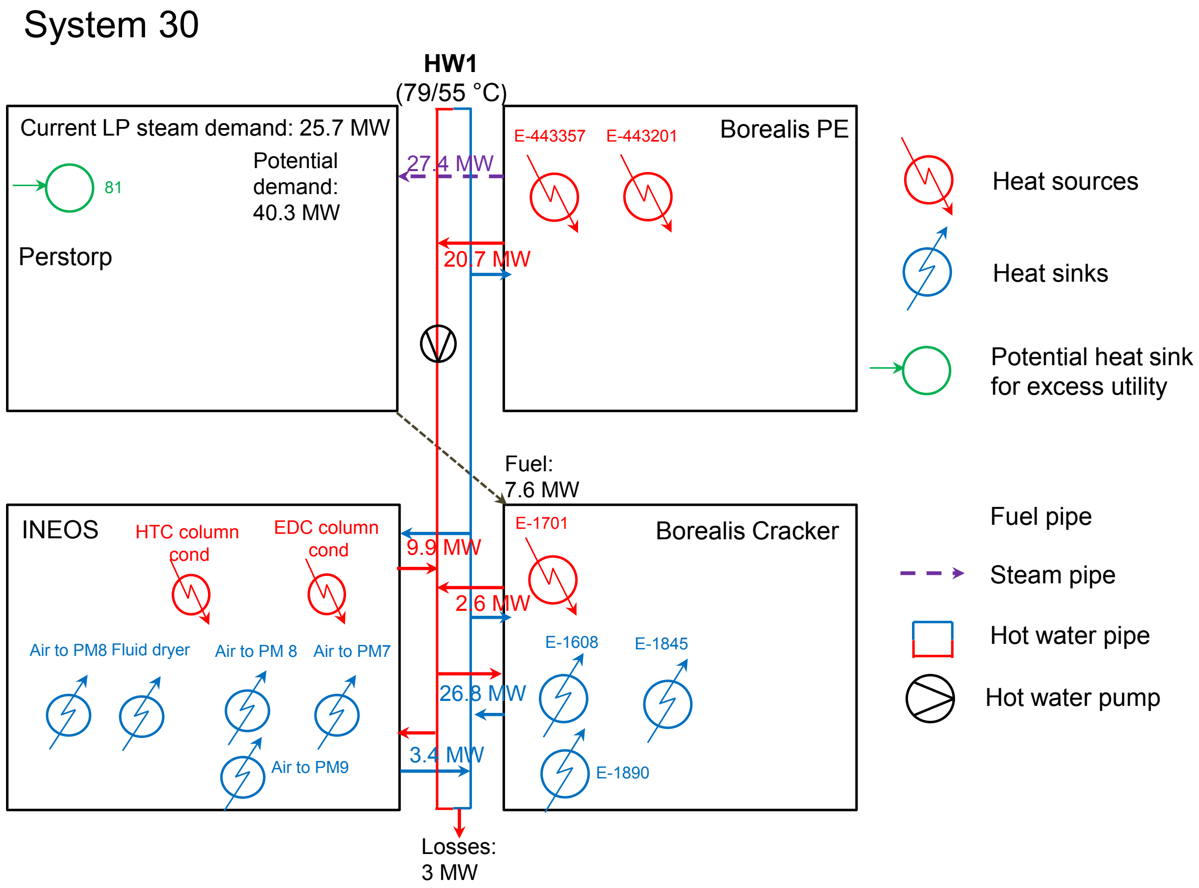

Table 15 Summary of the estimated investment cost for implementing the System 30.

Cost item	MSEK
HX heat supply	124
HX heat consumers	63
HX LP steam adjustments	1
HX heat loss compensation	24
HW piping	43
Steam/condensate piping	30
Fuel pipe	40
HW pumps	11
Total fixed capital	**336**

Table 16 Estimated revenues from steam and CW savings and operating costs

Revenues and Operating costs	MW	MSEK/yr*
Steam savings	30.6	98
CW savings	0.76 (electricity)	3.7
Operating costs (Maintenance + pump power)		9.7

* Assumed operating hours: 8000 h/yr

Table 17 Summary of steam and corresponding fuel savings (or opposite) and the savings allocation

Plant	Steam savings [MW]	Fuel savings [MW]
Borealis Cracker	1.5	1.9
Perstorp	25.7	32.1
INEOS	3.4*	3.4
Total savings	30.6	37.4

*HW replaces flue gas in the air dryers

System 40

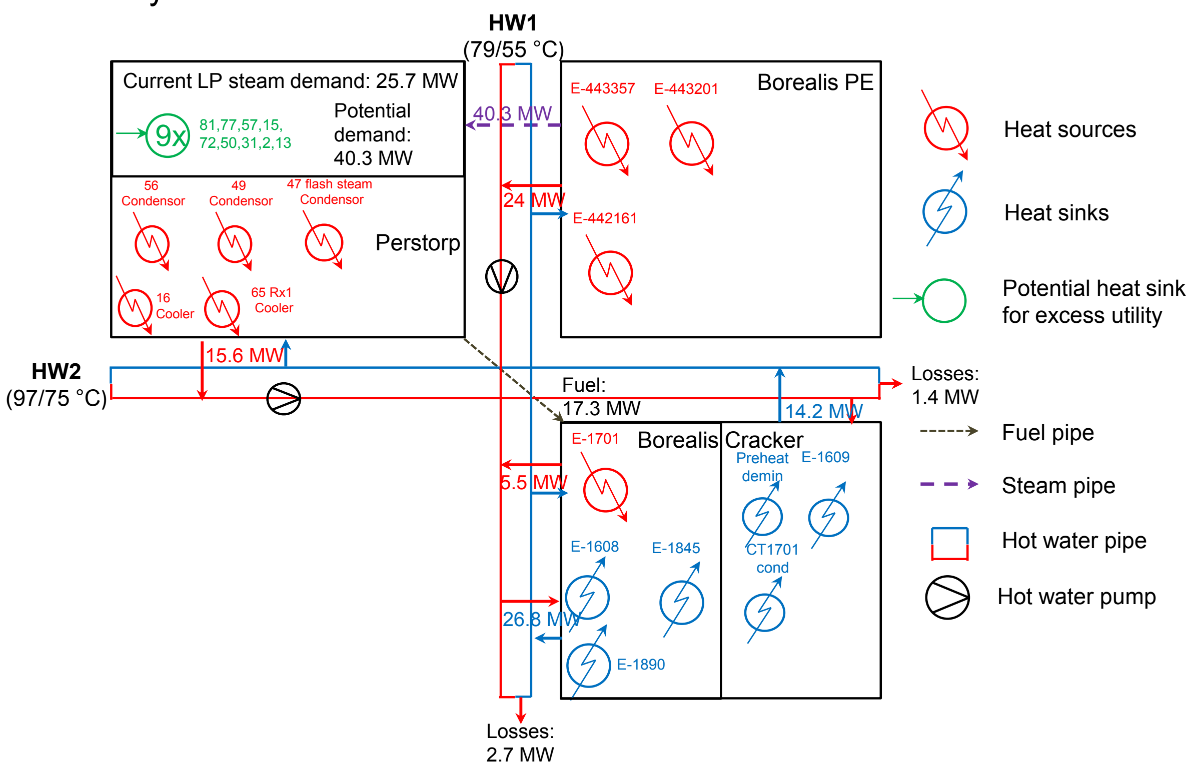

Table 18 Summary of the estimated investment cost for implementing the System 40.

Cost item	MSEK
HX heat supply	180
HX heat consumers	60
HX LP steam adjustments	12
HX heat loss compensation	29
HW piping	93
Steam/condensate piping	39
Fuel pipe	40
HW pumps	17
Total fixed capital	**470**

Table 19 Estimated revenues from steam and CW savings and operating costs

Revenues and Operating costs	MW	MSEK/yr*
Steam savings	40.3	129
CW savings	1 (electricity)	4.8
Operating costs (Maintenance + pump power)		13.3

* Assumed operating hours: 8000 h/yr

Table 20 Summary of steam and corresponding fuel savings (or opposite) and the savings allocation

Plant	Steam savings [MW]	Fuel savings [MW]
Borealis Cracker	16.8	21
Perstorp	24	30
Total savings	40.8	51

System 54

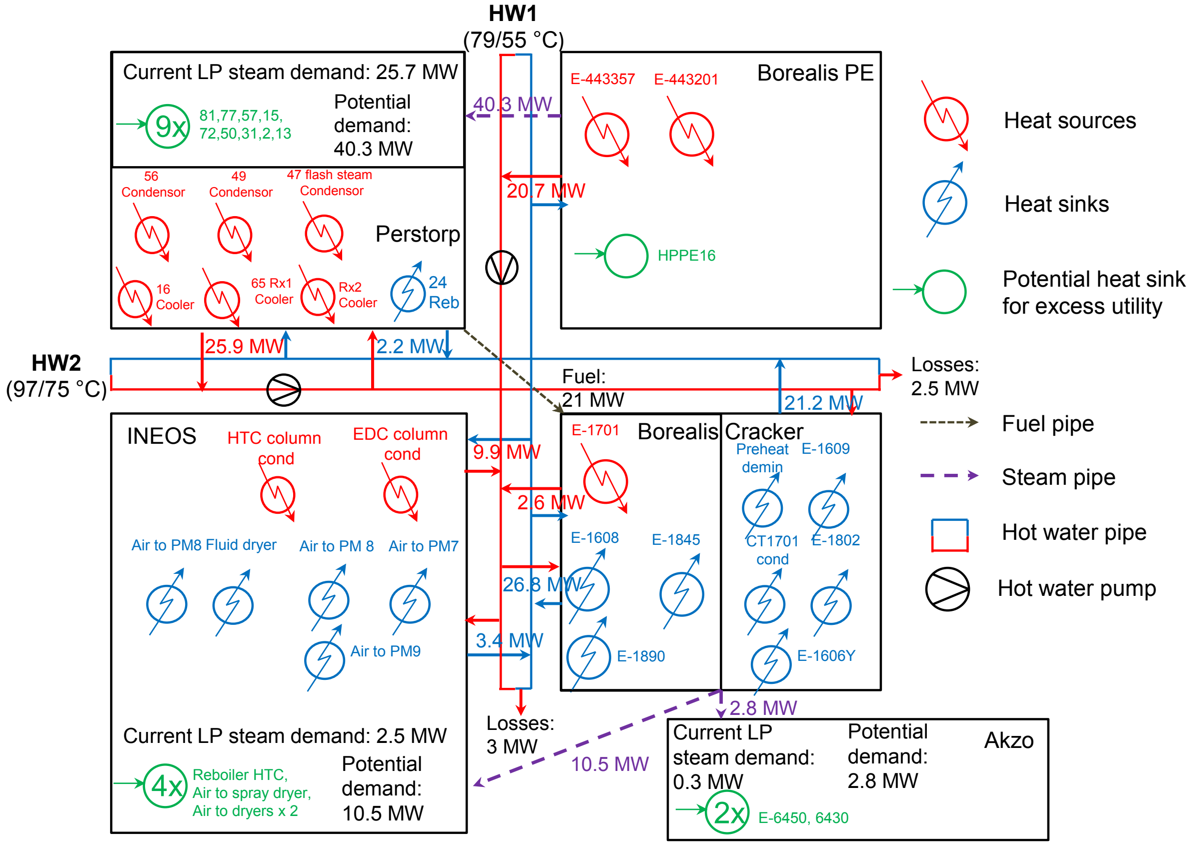

Table 21 Summary of the estimated investment cost for implementing the System 54.

Cost item	MSEK
HX heat supply	234
HX heat consumers	136
HX LP steam adjustments	25
HX heat loss compensation	39
HW piping	120
Steam/condensate piping	52
Fuel pipe	40
HW pumps	22
Total fixed capital	**668**

Table 22 Estimated revenues from steam and CW savings and operating costs

Revenues and Operating costs	MW	MSEK/yr*
Steam savings	53.6	172
CW savings	1.3 (electricity)	6.4
Operating costs (Maintenance + pump power)		18.5

* Assumed operating hours: 8000 h/yr

Table 23 Summary of steam and corresponding fuel savings (or opposite) and the savings allocation

Plant	Steam savings [MW]	Fuel savings [MW]
Borealis Cracker	16.8	21
Perstorp	24	30
INEOS	13.9	17.4
Akzo	2.8	3.5
Total savings	40.8	51