Optimisation of unit investment and load shedding in a steam network facing undercapacity

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Abstract:

Steam networks and their utilities should be dimensioned to satisfy day-to-day demand as well peaks. Peaks can be caused by unit start-ups, extreme weather conditions or combinations of high demand from process units. During maintenance operations or unexpected boiler shutdowns, periods of undercapacity may occur when steam demand surpasses the available steam production capacity. This can lead to boiler damage, network inoperability and production loss. Load shedding is a convenient way to prevent damage and reduce the impact of undercapacity.

A model is developed with the goal of optimising the flows of steam from producers to consumers through a steam network's headers, turbines and letdowns. The multi-period nature of the work ensures that nominal and peak demands for steam are properly taken into consideration. The model also investigates the trade-off between installing additional capacity versus production loss. A Mixed Integer Linear Programming (MILP) formulation is used to optimise the steam network operations, investment and load shedding decision-making.

A multi-period case study based on anonymised data is carried out on an industrial cluster. Solutions to steam production undercapacity are investigated in the form of load shedding and infrastructure investments.

Keywords:

Steam network, milp, resilience, undercapacity, optimisation, load shedding, cluster integration.

1. Introduction

Industrial processes can be heavily reliant on steam to supply process requirements such as heat, steam injections or to cogenerate mechanical power through turbines. Undercapacity of steam refers to situations where the demand for steam surpasses the ability to produce it. This can occur when boiler capacity is insufficient to meet demand either due to unexpected boiler shutdowns or extraordinarily high consumption. A solution to undercapacity is load shedding, the programmed shutting down of steam consumers, a concept frequently adopted in electrical networks [10].

During normal operations, the use of turbines between pressure levels can be maximised to produce valuable electricity while letdowns can be used in case of undercapacity to generate additional steam through their desuperheaters. Process units can simultaneously supply and consume steam at different pressure levels. Evaluating the economic and operational impacts associated to undercapacity and load shedding through unit shutdowns can become complicated, especially when dealing with a large number of units and periods. Through the use of a model exploiting Mixed Integer Linear Programing (MILP), economically optimal steam network flows can be determined. An optimal economic strategy for load shedding can also be developed through the association of penalty costs with load shedding.

Energy integration and pinch analysis studies on total sites [1] have permitted the development of methods for the optimal synthesis of utility systems [2]. The extension of these studies to multi-period problems [3-4] has in turn permitted for varying heat demand to be taken into consideration. These works do not however study the operations of the proposed steam networks. Steam network models using MILP formulations were introduced by Papoulias and Grossman [5]. These single-period studies were then extended to multi-period [6], while considering changeover costs associated to utility equipment start-ups and shutdowns. Further studies have combined more accurate representations of steam producing equipment into the models to include part load efficiencies [7]. While these papers examine the optimal operations and investments to be made in steam networks, they do not evaluate how to operate a steam network facing undercapacity caused by extreme events or boiler turnarounds and shutdowns

In this paper, we propose a MILP steam network model, which optimises the flow of steam through the network, indicating the optimal operational strategy to minimise the impact of undercapacity. The proposed mathematical model defines steam networks through the use of sets, thereby allowing complex systems to be defined in a simple way. As a consequence, multiple parallel steam networks and their integration can be studied.

Industrial clusters are important consumers of resources and have a lot to gain from integration, as demonstrated by [8]. Given the newly implemented European Energy Directive [9], industrial clusters are ideal targets for energy savings. Within this context, a multi-period case study of two industrial sites within a cluster, spanning a year of operations is studied. Boiler undercapacity is introduced to demonstrate the benefit of unit shedding. Investment scenarios including new boilers and synergies between the two industrial sites are included in the optimisation to identify longer-term solutions.

2. Steam network model

The developed steam network is based on the work of Papoulias and Grossman [5] and Iyer and Grossman [6].

2.1. Constraints

Each consumer and producer is defined by its flows, *N* is the set of flows Steam headers are defined for each steam pressure level of each site, *H* is the set of headers and *S* is set of sites. Minimum and maximum unit flow constraints are set for all steam network equipments as in [6]. For each unit flow, minimum values $F_{\min,nt}$, maximum values $F_{\max,nt}$ and binary variables y_{nt} are defined. y_{nt} has a value of 0 when the flow is off and 1 when it is on.

For steam network utilities:

$$F_{\min,nt} y_{nt} \le F_{nt} \le F_{\max,nt} y_{nt},\ y_{nt} = 0 \quad t = 1..T,\ n = 1..N \tag{1}$$

For process units:

$$F_{\min,nt} = F_{\max,nt},\ y_{nt} = 1 \quad \forall n,t \tag{2}$$

For shedable units:

$$F_{\min,nt} = F_{\max,nt},\ y_{nt} = 0 \quad \forall n,t \tag{3}$$

Mass balances are defined for each header (4), with O_h the set of flows entering header *h*, and I_h is the set of flows leaving header *h*.

$$\sum_{n \in I_h} F_{nt} - \sum_{n \in O_h} F_{nt} = 0, \qquad \forall n,t,\ h = 1..H \tag{4}$$

Shedding priorities are defined for each site (5). $G_{p,s}$ is the set of flows of priority *p* in site *s*. Multiple flows can belong to each priority level. The shedding priority constraint is defined as follows:

$$y_{nt} / n \in G_{p,s} \geq y_{nt} / n \in G_{p-1,s} \geq ... \geq y_{nt} / n \in G_{1,s} \quad \forall n,t,\ s = 1..S \tag{5}$$

Turbines are defined as in [5]. The outlet flow of letdowns can be desuperheated by a factor w_l (6), where O_l is the set of flows entering letdown *l*, and I_l is the set of flows leaving letdown *l*. O_l and I_l only contain one flow each.

$$\sum_{n \in O_l} F_{nt} - \sum_{n \in i_l} F_{nt}(1 + w_l) = 0, \qquad \forall n,t,\ l = 1..L \tag{6}$$

2.2. Objective function

The operational costs of the system are the fuel costs and the penalties associated to unit shedding. If a unit is forced to shut down due to undercapacity, a penalty is associated to it. Generated electricity can be sold to the grid. The operational costs of the steam network are therefore calculated as follows (7), with c_{nt} the cost of operating flow *n* at time *t*, P_n the penalty associated to flow *n* being deactivated, e_t the price of electricity at time *t*, W_{nt} the work produced by flows *n* at time *t*,

$$OPEX_{nt} = c_{nt}F_{nt} + (1 - y_{nt})P_n - e_t W_{nt} \quad \forall n,t \tag{7}$$

The investment costs of units are the sum of their fixed investment costs $I_{\text{fixed, n}}$ and variable investment costs $I_{\text{variable,n}}$ (9).

$$F_n = \arg\max_t F_{nt} \quad \forall n,t \tag{8}$$

$$CAPEX_n = I_{\text{fixed, n}} + I_{\text{variable,n}} F_n \quad \forall n,t \tag{9}$$

The objective function of the optimisation is to minimise the weighted sum of the operational costs and investment costs (10), subject to the constraints of the model with d_t the duration of period *t*.

$$Obj = \min \sum_{\text{t}} \sum_{\text{n}} OPEX_{\text{nt}} d_t + CAPEX_n \quad \forall n,t \tag{10}$$

2.3. Discussion on load shedding

A question can be raised about the simultaneous need for the shedding priorities and penalty costs in the optimisation. Shedding priorities are an operational reality for most industrial sites, as the shutdown of certain upstream units will severely affect downstream units. However, in an optimisation using only shedding priorities, the optimisation will always select to turn off units in order to reduce steam production costs. The penalty costs, prevent this form happening. One could consider using uniquely fine tuned penalty costs to overcome this issue, however experience has shown that this often leads to the steam network voluntarily shutting off units to reduce costs, despite having remaining steam production capacity in the boilers, which is not an acceptable solution for operators of production plants.

3. Case study description

A case study is used to demonstrate the proposed method. The case refers to an industrial cluster in which two production sites (Site 1 and Site 2) are in geographical proximity. Both sites contain their own utility systems and boilers and are connected to two Central Boilers that provides them with additional steam. Both sites have 6 units and site utilities, which require steam to operate. The major consumers of site utilities are pipe tracing and tank heating. Figure 1 shows a schematic of the two sites under study.

Both sites are heavily dependent on the two Central Boilers that supply steam all year round. In this case study, we consider that the Central Boilers are ageing and often going offline due to technical difficulties. Solutions are therefore investigated to mitigate the effects of unexpected shutdowns.

Load shedding is proposed as a short-term solution, while two investment solutions are analysed. Firstly, two pipes are proposed between Site 1 and Site 2 to permit the exchange of steam between themselves. Secondly new boiler investments are considered.

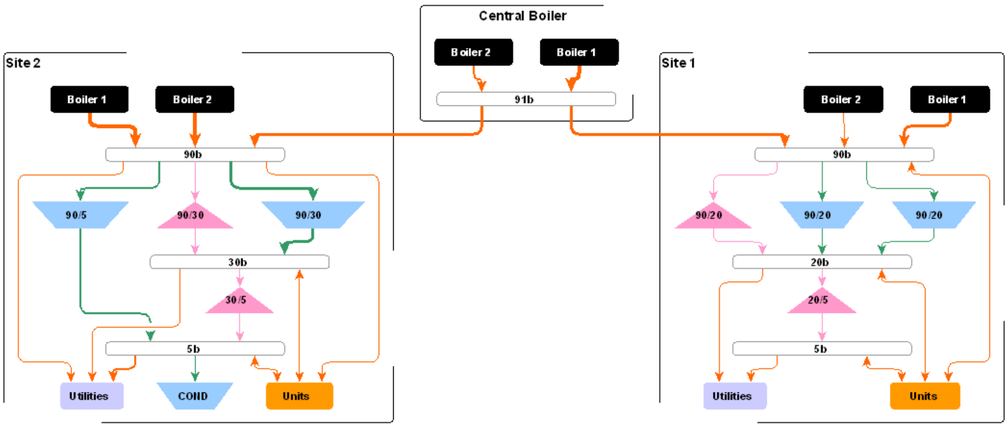


Figure 1. Schematic of the cluster under study

3.1. Site 1

Site 1 produces steam at 90 bar in its two boilers and in one of its units. The 90 bar header is connected to a 20 bar header through two steam cogeneration turbines and a letdown. Several units consume 20 bar steam. The 5 bar header is fed exclusively by unit auto-production and a letdown from the 20 bar header. Key properties of the steam network equipment can be found in Table 1. Both letdowns are connected to desuperheaters, which produce additional steam by cooling the letdown steam. Table 2 shows the mean steam demand (consumption – production of steam) by the units and utilities of site 1. Electricity produced is sold to the grid at 46 €/MWh.

Table 1. Properties of Site 1's steam network equipment

	Inlet [bar]	*Outlet [bar]*	$F_{\min,n}$ *[t/h]*	$F_{\max,n}$ *[t/h]*	*Other*
Boiler 1&2	-	90	30	90	19 €/t steam
Turbine 1&2	90	20	52	90	$\eta_{isentropic} = 0.7$
Letdown 1	90	20	0	300	Desuperheating adds 12%
Letdown 2	20	5	0	210	Desuperheating adds 6%
X	5		0	100	Atmospheric discharge
Desuperheaters					5 €/t water

Figure 2 shows the steam demand of Site 1 for each pressure level and a year of operations. Steam demand is mostly in 20 bar steam representing 68% of total on average. The mean demand is of 163 t/h with a peak at 207 t/h. This implies that Site 1 cannot be self-sufficient in steam as its production capacity is only 180 t/h.

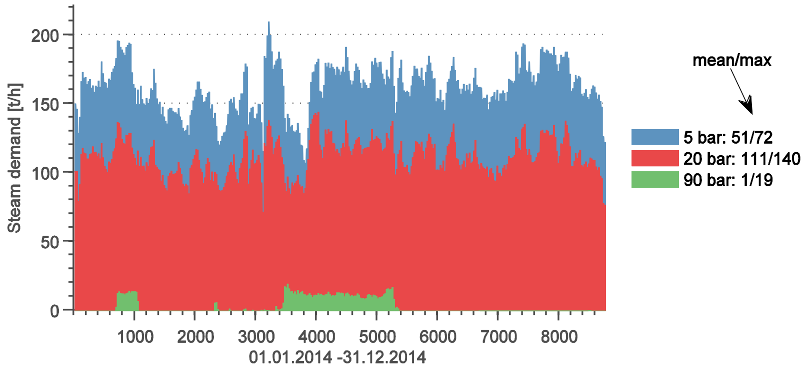


Figure 2. Site 1's production and consumption of steam by pressure level

Table 2. Mean demand of steam in Site 1

Steam demand (Consumption-Production)			
	90 bar	*20 bar*	*5 bar*
A		11.6	-3.9
B		9.8	3.0
C	14.1	9.4	-12.5
D	-13.1	8.4	8.7
E		19.9	14.2
F		16.3	1.1
Utilities		37.5	26.8
Utilities S		7.2	13.6
Total	1	120.1	51

3.2. Site 2

Site 2 also produces steam through two identical boilers. Two cogeneration turbines connect the 90 bar header to the 30 bar header and 5 bar header respectively. Letdowns also connect the 90 bar to the 30 bar header and the 30 bar header to the 5 bar header. A condensing turbine also exists on the 5 bar header. The key equipments of the site are described in Table 3. Table 4s shows the mean demand of the units of Site 2.

Figure 3 shows steam demand for Site 2 according to pressure levels for a year of operations. The figure indicates that most of the steam is consumed at 30 bar (47%) and that the 90 bar consumption is important as well. The average demand is of 339 t/h and the peak demand is 475 t/h. This indicates that Site 2 cannot be self-sufficient in steam, with only 320 t/h of installed boiler capacity.

Table 3. Properties of the Site 2's steam network's equipment

	Inlet [bar]	*Outlet [bar]*	$F_{\min,n}$ *[t/h]*	$F_{\max,n}$ *[t/h]*	*Other*
Boilers 1&2	-	90	52	160	20 €/t steam
Turbine 1	90	30	50	112	$\eta_{isentropic} = 0.7$
Turbine 2	90	5	13	60	$\eta_{isentropic} = 0.7$
Turbine C	5	0	13	39	$\eta_{isentropic} = 0.6$
Letdown 1	90	30	0	300	Desuperheating adds 8%
Letdown 2	30	5	0	200	Desuperheating adds 10%
X	5		0	100	Atmospheric discharge
Desuperheaters					5 €/t water

Table 4. Mean demand in steam of Site 2

Steam demand (Consumption – Production)			
	90 bar	*30 bar*	*5 bar*
A	114.3	-57.8	-39.0
B		32.3	9.5
C		66.0	12.9
D		7.8	0.4
E		48.7	-29.5
F		18.6	27.5
Utilities	3.8	27.0	64.6
Utilities S1		3.6	13.8
Utilities S2		5.3	13.8
Total	118.2	151.4	74.0

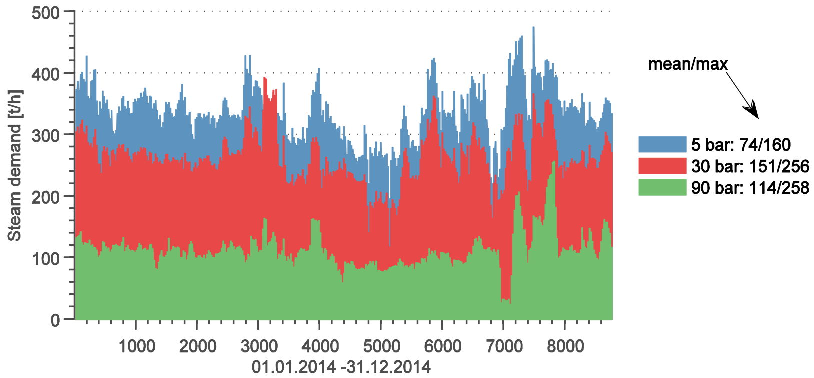


Figure 3. Site 2's production and consumption of steam by pressure level

3.3. Central Boilers

The Central Boiler house is made up of two high pressure boilers, which can supply 90 bar steam to Sites 1 and 2 as, described in *Table 5.*

Table 5. Properties of the Central Boiler steam network's equipment

Equipment	*Inlet [bar]*	*Outlet [bar]*	$F_{\min,n}$ *[t/h]*	$F_{\max,n}$ *[t/h]*	*Other*
Boilers 1&2	-	90	50	150	24 €/t steam

3.4. Cluster demand

In order to identify investment strategies to replace the Central Boilers, one can look at the peak demand of each site, respectively 207 t/h and 475 t/h for Site 1 and 2.This implies that a total of 682 t/h of steam production capacity would be required in the cluster to supply each site individually. Figure 4 shows the load duration curves of the total cluster demand, corresponding to the sorted sum of the cluster's demand. The analysis of the load duration curves also clearly shows that both sites will regularly be dependent on the two Central Boilers to supply their steam, more than 89% of the time (without taking into consideration the desuperheating potential from the use of letdowns).

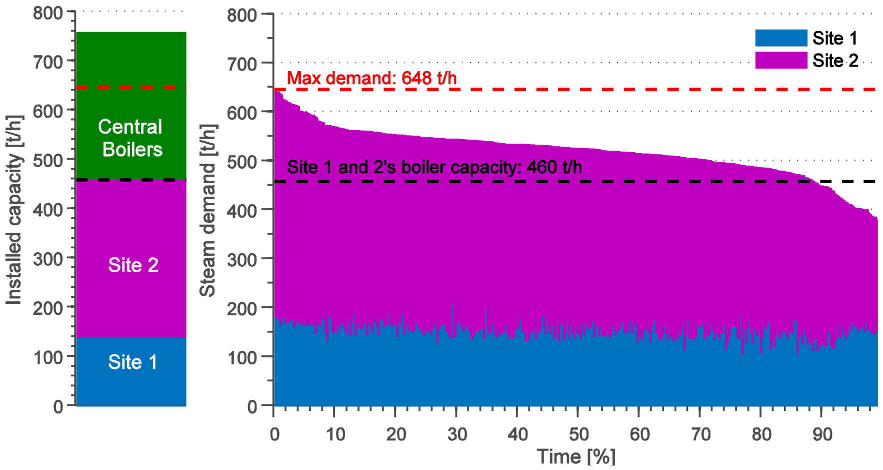


Figure 4. Load duration curve of the cluster's steam demand

The peak cluster demand lies at 648 t/h as illustrated by the dotted red line. If we were to consider a unique boiler system connected to both sites, it can be said that 648 t/h of installed steam production capacity would be required to match the demand of the cluster (without considering the additional steam produced from desuperheating of letdowns). The question remains if this could be reduced through an economic optimisation of the networks installed capacity.

3.5. Load shedding

The principal means of dealing with undercapacity in the short term is to halt the demand of steam from consumers, by shutting units down. For both of the sites, shedding priorities have been attributed to each unit, as well as a financial penalty associated with the units being taken offline, as can be seen in

Table 6.

Table 6. Shedding priorities and penalties

Site 1	*Priority*	*Penalty [k€/h]*	Site 2	*Priority*	*Penalty [k€/h]*
Unit A	5	10	Unit A	No shedding	
Unit B	3	5.6	Unit B	4	10
Unit C	4	13.8	Unit C	4	15
Unit D	No shedding		Unit D	2	2.8
Unit E	No shedding		Unit E	6	20
Unit F	2	7.2	Unit F	5	15
Utilities	No shedding		Utilities	6	15
Utilities S	1	6	Utilities S1	1	1.2
			Utilities S2	3	1.2

3.6. Investment options

Four investment options are proposed in order to replace the Central Boilers and increase synergies between adjoining sites.

1. High Pressure (HP) boiler: a 90 bar boiler is considered, connected to the 90 bar headers of Site's 1 and 2.
2. Medium Pressure (MP) boiler: a 30 bar boiler is considered, connected to the 30 bar header of Site 2 and the 20 bar header of Site 1 through a desuperheater, which increases the debit by 3.5%.
3. Relief line S1 > S2: As most steam demand in Site 2 is 30 bar, a pipe connecting the 90 bar header of Site 1 to the 30 bar header of Site 2 and a desuperheater (+8%) are considered.
4. Relief line S2 > S1: Similarly, a pipe connecting the 30 bar header of Site 2 to the 20 bar of Site 1 with desuperheating (+3%) at destination are considered.

The investment and operational costs for the options proposed are described in Table 7. Investment costs are stated in annualised costs considering a 25 year life expectancy and an interest rate of 6%.

Table 7. Investment and operational costs of proposed equipments.

	Fixed Investment [k€/yr]	*Variable investment [k€/t•yr]*	*Operational [€/t]*
90 bar boiler	1600	32	24
30 bar boiler	1360	16	21
Relief line S1	90	0	0
Relief line S2	80	0	0

4. Case study load shedding and investment scenarios

The load duration curve analysis has shown that Sites 1 and 2 are dependent on the two Central Boilers for steam production. For this case study, we wish to evaluate the impact of the Central Boilers going offline and investment options to replace them. Several scenarios are defined and tested with the proposed methodology. The key decisions made by the MILP optimisation are the pathways of steam from producers to consumers (through turbines and letdowns), load shedding when facing undercapacity and the choice in technologies to invest in.

4.1. Scenario description

Scenarios 1 and 2 study the system under the current configuration, the operability issues and costs associated to the Central Boilers going offline.

- Scenario 1 considers the Central Boilers to be online in order to evaluate baseline costs.
- Scenario 2 considers the Central Boilers offline to demonstrate the interest of load shedding and establish the worst-case penalty costs and operability issues.

Investment strategies are evaluated to overcome undercapacity issues and replace the Central Boilers in scenarios 3 to 7.

- Scenarios 3 explores how the relief lines help to mitigate load shedding by synergising the adjoining sites, through a conservative sharing strategy. In a conservative strategy, the relief lines of a site are closed in each time step where undercapacity is present.
- Scenario 4 explores the use of the relief lines with a liberal sharing strategy, in which the relief lines always remain open.
- Scenario 5, the optimisation chooses between the HP boiler, MP boiler and load shedding to minimise costs for the steam network.
- Scenario 6 is same as scenario 5, with load shedding disallowed.
- Scenario 7 is given free choice on load shedding, investments of boilers and relief lines, using a liberal sharing strategy.

4.2. Results

The key findings are present in Figure 5. The size and types of boilers chosen by the optimisation in scenarios 5 to 7 are also presented in the figure. Table 8 resumes the load shedding according to each site for scenarios 2 to 5.

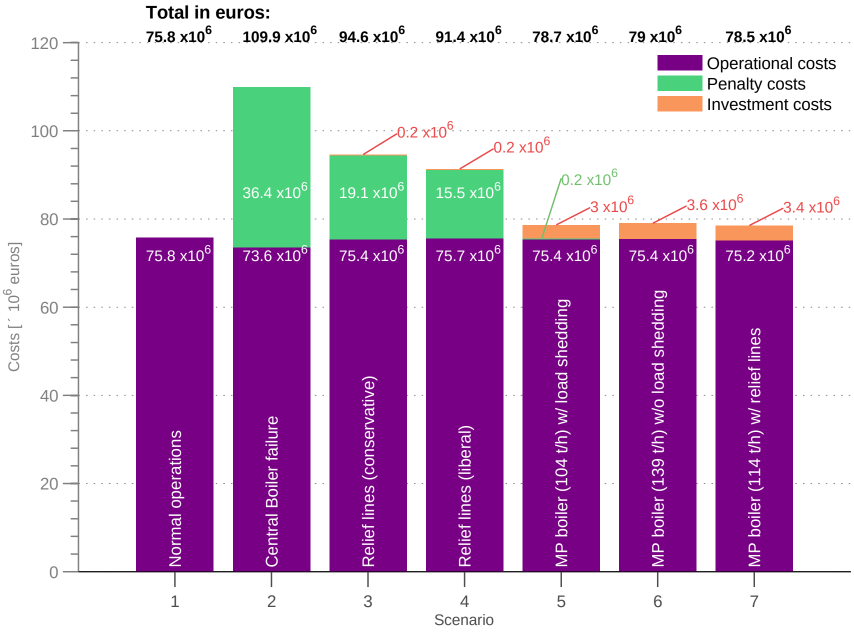
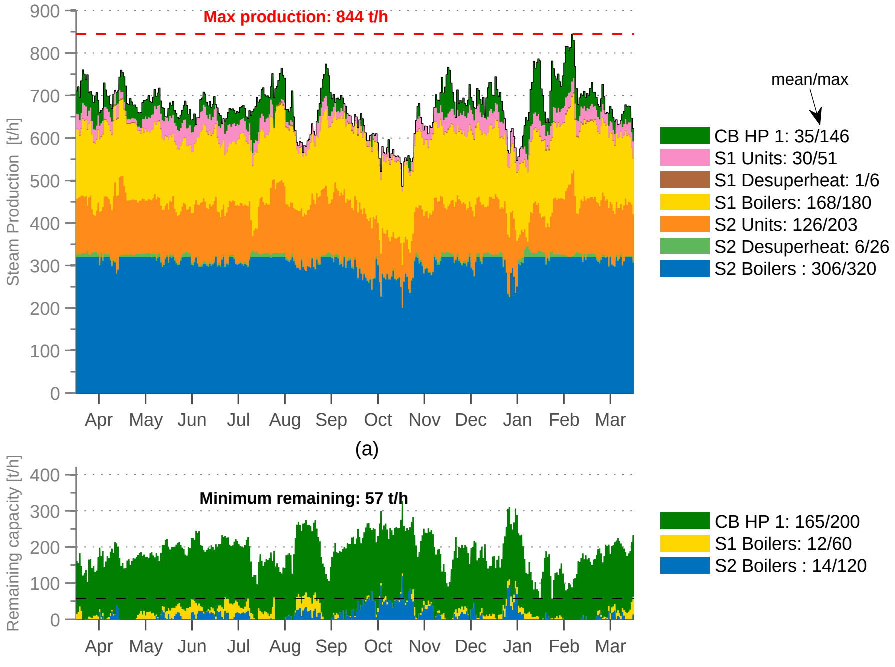


Figure 5. Operational, penalty and investment costs for the evaluated scenarios.

Scenario 1 establishes the operating costs of the steam network at 75.8 M€ under normal operating conditions. Figure 6 (a) shows the producers of steam. Given the lower operational costs of the Site 1 and 2's boilers, these have a higher utilisation rate than the Central Boilers. Figure 6 (b) shows the remaining steam production capacity in the cluster's boilers. At peak demand, the minimum remaining capacity falls to 57 t/h, which implies that all of the steam boilers of the site are necessary to avoid load shedding. Total steam production lies at 5965 kt/yr with a peak demand of 844 t/h, of which 643 t/h are produced in boilers, the rest coming from process units and desuperheaters.



(a)

(b)

Figure 6. Production of steam (a) and remaining capacity of boilers (b) for Scenario 1.

Table 8. Load shedding quantities and costs

	Site 1			Site 2		
	Total [kt/yr]	Peak [t/h]	Cost [M€/yr]	Total [kt/yr]	Peak [t/h]	Cost [M€/yr]
Scenario 2	5	48	0.9	251	201	35.5
Scenario 3	5	48	0.9	132	138	18.2
Scenario 4	18	52	4	96	138	11.5
Scenario 5	0	0	0	3	46	0.2

In scenario 2, the Central Boilers are considered to be offline. As such there are not enough boilers to meet demand. Consequently operational costs fall slightly as less steam is produced, though penalty costs are very significant at 36 M€, due to the important amount of load shedding. The black line in Figure 7 shows the total demand for steam and the area between it and the shaded areas represents the total amount of load shedding (256 kt/yr). Table 8 indicates that 98% of the load shedding is caused by Site 2's undercapacity, with a peak at 201 t/h, corresponding to priority 4 load shedding. Under such conditions it can be considered that Site 2 would not be operable, though Site 1 would be. It can be noted that the desuperheaters have a higher utilisation rate here than in scenario 1.

The results of scenario 3 show the interest of the relief lines. By making use of the remaining capacity in Site 1's boilers, Site 2 is able to reduce its penalty costs to 19.1 M€ by investing 0.2 M€ in the relief lines. In this scenario, a site's relief lines are shut any time it faces undercapacity (conservative strategy). Total load shedding is brought down from 256 kt/yr in scenario 2 to 136 kt/yr in scenario 3.

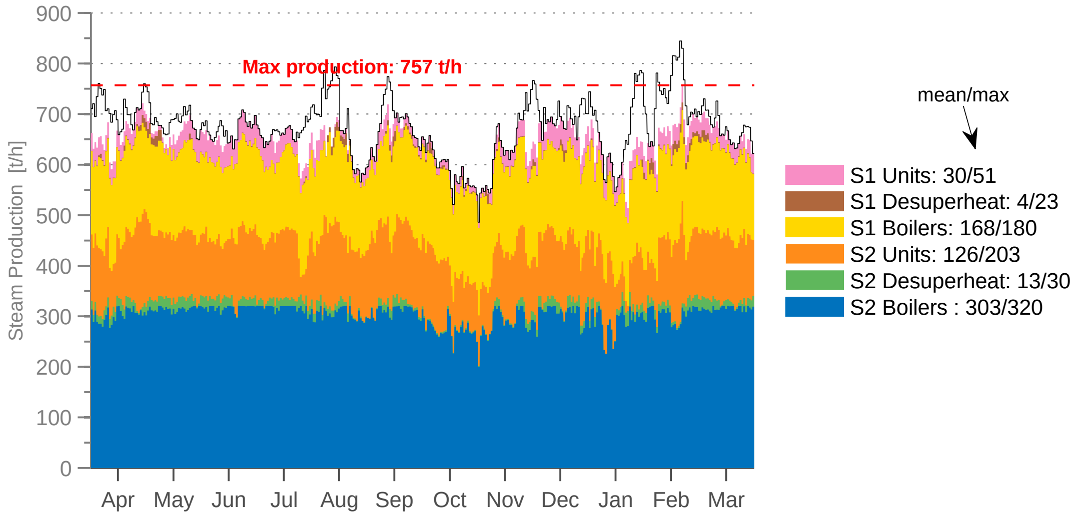


Figure 7. Steam distribution and load shedding with Central Boilers offline (Scenario 2)

In scenario 4, penalty costs are further reduced to 15.5 M€ by keeping the relief lines open at all times (liberal strategy). Total shedding is reduced to 114 kt/yr. Through the liberal strategy, more shedding is induced in Site 1 in order to reach a global economic optimum, bringing its penalty costs from 0.9 M€ to 4 M€.

In scenarios 3 and 4, site operations are seriously compromised. As such, the relief lines cannot provide a long-term solution to undercapacity; they can however be of great use for dealing with punctual boiler failures.

Scenario 5 identifies the optimal size of a replacement boiler in order to reduce costs. The optimisation was given the choice between a high pressure (90 bar) and medium pressure (30 bar) boiler to invest in. Results indicate that the economically optimal solution for boiler investment is a 104 t/h medium pressure boiler. Table 8 indicates that despite investing in a boiler, the optimisation still chooses slight load shedding in Site 1 (priority 3 shedding, peak 46 t/h), highlighted in red in Figure 8. The investment costs of the proposed solution lie at 3 M€ with significantly reduced penalty costs.

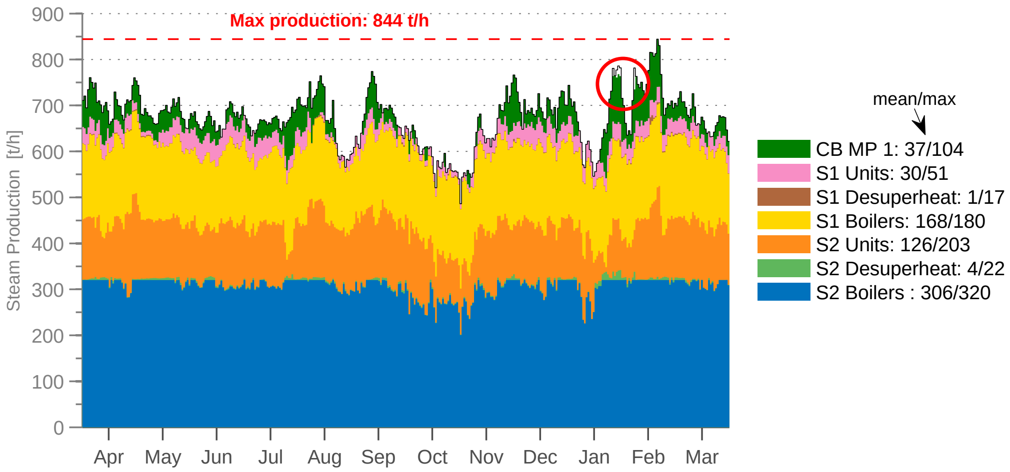


Figure 8. Optimal investment to replace Central Boilers (scenario 5)

In scenario 6, the optimisation was asked to optimally choose a boiler to invest in when load shedding is disallowed. As a result, all penalty costs are eliminated, though investment costs are increased to 3.6 M€ as the optimisation chooses a 139 t/h medium pressure boiler rather than the previously identified 104 t/h boiler, leading to slightly higher overall costs.

Lastly, in scenario 7, the optimisation was permitted to invest in all of the mentioned equipments. Shedding was permitted and a conservative shedding strategy was used concerning the relief lines.

The optimal results propose to invest in a 114 t/h medium pressure boiler as well as both the relief lines. Investment costs are consequently 3.4 M€, and operational costs are slightly lower than in current normal operations (by 0.6 M€) due to the added flexibility of the relief lines. The proposed solution removes the need for load shedding. Figure 9 illustrates the distribution of steam. It can be seen that Site 2’s desuperheaters are used quite consistently, with a peak of 24 t/h. This result indicates that the optimisation chooses to invest in a smaller boiler and use the letdowns rather than invest in a bigger boiler to make use of the cogeneration turbines.

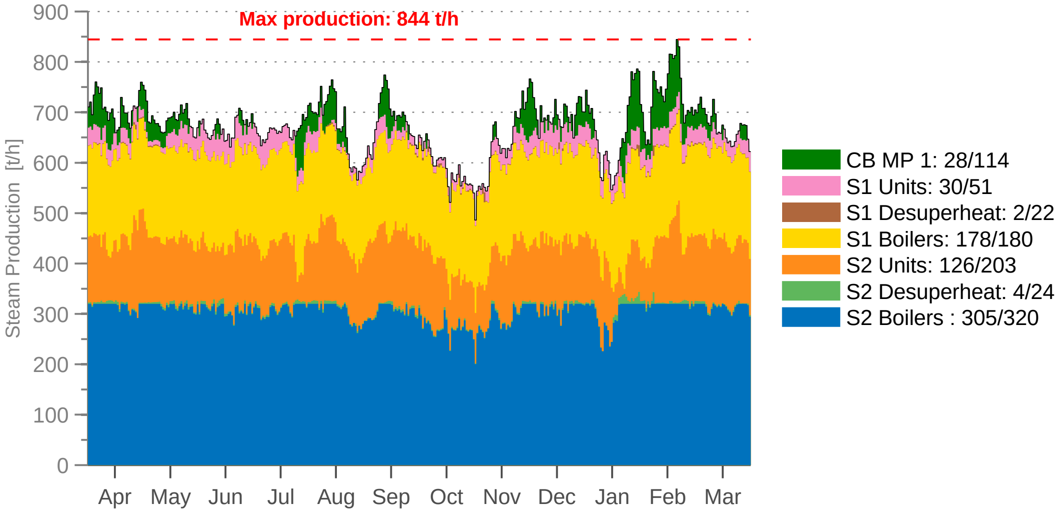


Figure 9. Distribution of steam with optimal investments (scenario 7).

5. Discussion

In the load duration curve analysis (3.4), a question was raised about how much boiler capacity would be required to meet the cluster’s steam demand. The results from this optimisation indicate that the economically optimal total installed capacity would be 614 t/h (180 t/h at Site 1, 320 t/h at Site 2 and 114 t/h in the Central Boiler). In order to meet the peak boiler demand of 643 t/h, the solution would make the cluster very dependant on the additional steam produced by the letdown’s desuperheaters. This may be an optimal solution, however it leaves no margin for error stemming from potential boiler failures or higher demands in the future. Any investment would have to take into consideration boiler failures, and oversizing in order to provide resilience to the steam network.

Comparing scenarios 3 and 4 shows how different operating strategies can lead to important variations in costs. It can be said that a liberal sharing strategy, in which relief lines stay open at all times is globally beneficial to the cluster. However, in reality it may be complicated to request independent businesses to voluntarily load shed in order to reach a global optimum.

Comparing scenarios 5 and 6 provides interesting insights into the benefits of load shedding. Through very occasional shedding, the required investment in boiler capacity of the cluster can be reduced from 139 t/h to 104 t/h. In the case where investments are hard to justify, load shedding can be an interesting lever for decision making.

6. Conclusion

A steam network model has been developed to thermoeconomically optimise the flows of steam from producer to consumer when facing undercapacity. Load shedding is proposed as means of dealing with unexpected or planned boiler shutdowns. At the cost of an economic penalty, units can be shut off for indefinite periods of time in order for supply to match demand, though an order of priority must be respected. The optimisation is written as a mixed integer linear programming problem in order to optimally choose equipment activation and investments. The key choices given to the optimisation are the pathways of steam through turbines and letdowns (and their desuperheaters), investment decisions among several available equipments and load shedding.

A case study was used to demonstrate the advantage of load shedding, in order to prevent a collapse of the steam network. The study of two neighbouring industrial sites within a cluster showed that through synergies of the steam networks, the impact of undercapacity can be reduced significantly. Furthermore, an optimisation of the steam network including investment in a new boiler showed that network operability can be maintained by installing a new smaller and lower pressure boiler.

The advantages of consolidating the steam networks into one network using liberal synergy strategies is an important finding of this work, which could contribute towards reducing the investment costs and energy bills of industrial clusters but more importantly provide insights into dealing with punctual undercapacity issues.

The optimisation model identifies the best size of technologies to invest in, however these solutions lack resilience. In effect, any boiler trips or exceptionally high steam demand could easily lead to undercapacity. An interesting avenue of research would lie in identifying optimally resilient steam network investments, which could also interest industrials.

This steam network model could also be expanded to include other issues such as thermal storage, scheduling problems and more complex investment propositions such as cogeneration plants, heat pumps, and thermal and mechanical vapour recompression.

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