PINCH ANALYSIS :
For the Efficient Use of Energy, Water & Hydrogen

OIL REFINING INDUSTRY
Energy Recovery at a Delayed Coker Unit

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PINCH ANALYSIS APPLICATION EXAMPLE

Oil Refining industry

Energy Recovery at a Delayed Coker Unit

This example is a description of the steps required to carry out a Pinch study of a refinery Delayed Coker Unit. The simplified data used to illustrate the procedure is based on an amalgamation of four different existing Delayed Coker Units. The objective of this presentation is to illustrate in concrete terms the different steps in a Pinch analysis of an industrial process in a retrofit situation. It is one of the step-by-step examples that support the technical guide entitled *Pinch Analysis for the Efficient Use of Energy, Water and Hydrogen* produced by Natural Resources Canada. The Pinch concepts used in this example are presented in more details in this guide.

Pinch techniques were initially developed to address energy efficiency issues in new plant design situations. The techniques need to be modified for retrofit studies like the one described here. The key distinction is that in retrofit situations the analysis must take into account equipment that is already installed, whereas in a new design situation the designer has the flexibility to add or delete equipment at will. This difference makes the retrofit problem inherently more constrained.

Although different approaches are possible, in this example we will be following perhaps the simplest one for Pinch studies in retrofit situation, which can be summarized in the following steps:

❶ Obtain data relevant to Pinch study

❷ Generate targets for each relevant utility

❸ Identify major inefficiencies in the heat exchanger network

❹ Define options for reducing or eliminating the largest inefficiencies

❺ Evaluate options

❻ Select the best option or combination of options

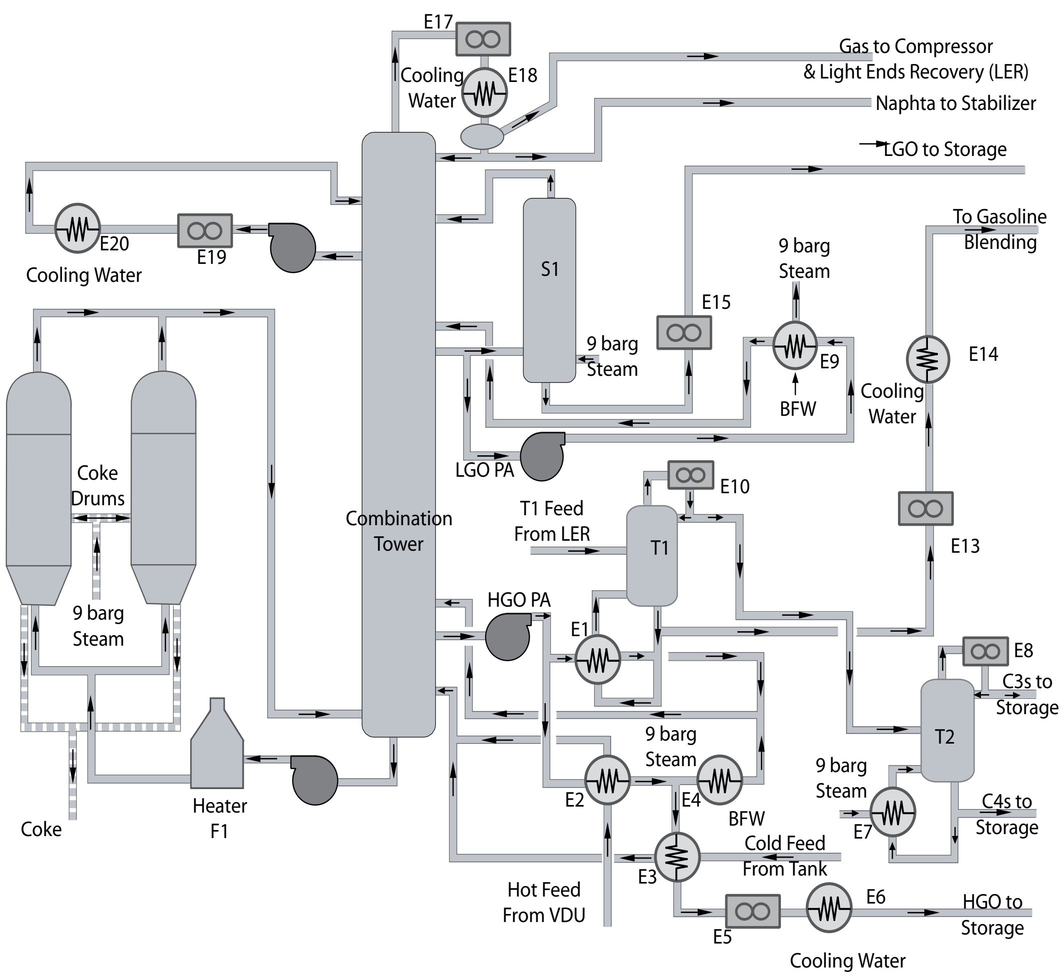
The objective in the Pinch study is to make changes that reduce the net cost of utilities for the process. All costs mentioned in this text are given in Canadian dollars (CAN$).

Process Description

The process under examination is based on the coke drums and fractionation section together with the associated preheat train, pumparounds, product streams and heat recovery network of an existing 30,000 BPD[1] Delayed Coker Unit[2].

The process is illustrated as a simplified process flow diagram (PFD) in Figure 1, where main process streams, equipment items, and heaters and coolers are shown with the existing heat recovery network.

Figure 1 Simplified Process Flow Diagram of the Delayed Coker Unit



[1] BPD: barrel per day

[2] There are also several different continuous coking designs. The main difference between these and Deayed Cokers is that the continuous coking processes typically use ony a single fluid bed reactor in place of multiple batch coke drums. However, pinch analyses of both Delayed cokers and continuous coking processes have generally shown little or no scope to improve the heat integration of the coke drums or reactors themselves, and as the rest of the process is similar for all cokers, the types of heat integration opportunities identified in all types of cokers are also similar. This example sould therefore be useful to people whose interest is in continuous coking processes as well as Delayed Cokers

There are two feed streams, one coming hot from a vacuum distillation unit, and the other coming cold from a storage tank. The feeds pass through preheat exchangers and then enter the combination tower, where the lighter components are stripped out. The heavier components leave from the bottom of the tower and go via a fired heater to the coke drums. These are operated in batch mode, with drums alternately making coke and having coke removed mechanically. A large amount of steam is used between cycles to steam out the drums, and much heat is lost in the coke product, but in general it is not economic to recover this heat due to the intermittent nature of the operations.

The hot vapors from the coke drums (around 500°C) go to the bottom of the combination tower. In our example the combination tower has two pumparounds, one for light gasoil (LGO) and the other for heavy gasoil (HGO). These circuits provide a convenient means for removing heat from the tower, in feed preheat, driving distillation tower reboilers, and 9 barg steam generation. There are also HGO and LGO products – the former taken as a draw from the HGO pumparound, and the latter taken from a side-stripper S1, which uses 9 barg steam to control the end-point of the product. There is also a naphtha product obtained from the overhead condenser. The uncondensed overheads go to a compressor and light ends recovery (LER) condenser (not shown on the PFD), where additional liquid hydrocarbons are recovered. These liquids are fed to a distillation train consisting of T1 (debutanizer) and T2 (depropanizer) to obtain the desired hydrocarbon fractions.

The arrangement shown in the PFD is a composite based on four different Delayed Coker Units. The design is therefore typical of many Delayed Cokers, although identical to none; and the Pinch analysis shown here is indicative of the results that will commonly be obtained with Delayed Cokers.

Step 1: Obtain Data Relevant to the Pinch Study

Operating Data

Data needed for the Pinch study includes heat loads and temperatures for all of the utilities and process streams. In most cases this is obtained from a combination of test data, measured plant data and simulation, often supported by original design data. These data can be divided into two categories: process data and utility data.

Additional information needed to quantify potential savings include:

- Furnace efficiency: 85%, and
- On-stream factor: 96% or 8,400 hours/year.

Economic Data

The other type of data required is economic data. In the early stages of a study, the most important economic data relates to the cost of energy. Later capital costs become important; this is discussed under STEP 5.

Energy prices generally depend on which utility is being considered, and in the present example we need to consider furnace heating and 9 barg steam (consumption and generation). The relevant prices are:

- ❒ Fuel: 5.00 CAN$/GJ,
- ❒ 9 barg steam consumption (with condensate recovery): 4.70 CAN$/GJ,
- ❒ 9 barg steam generation: 4.35 CAN$/GJ.

Steam Pricing

The difference in price between 9 barg steam consumption and 9 barg steam generation is due to the sensible heat in the boiler feed water (BFW) and condensate. When the steam is generated in a boiler, we must supply sensible heat to the BFW before we can evaporate it to make steam. The cost of supplying this sensible heat (per kJ) is the same as the cost (per kJ) of supplying the latent heat and superheat in the steam. However, when we consume steam (e.g. in a reboiler) the condensate that we obtain is typically flashed to a lower pressure header where steam has a lower value, and often also to the atmosphere where it has no value, before returning to the deaerator, and from there to another steam generator. We therefore recover a smaller amount of "valuable" energy when we consume steam than the amount of heat we have to supply when we generate the same steam. The price we assign to steam consumption (per GJ) must therefore be higher than the value we assign (per GJ) to heat recovered for steam generation.

Utility pricing – especially steam pricing – is a complex issue, and in many Pinch studies steam system models are used to develop an appropriate price structure.

The ambient cooling utilities – air and water – are comparatively inexpensive, and were ignored in this example.

Once the data required for the analysis has been collected, we need to put it in the proper format for the Pinch study. This is often referred as the data extraction phase. The main rules for data extraction are presented in the *Pinch Analysis for the Efficient Use of Energy, Water and Hydrogen* guide of Natural Resources Canada.

Data Extraction: Process Data

Heat loads and temperatures for all the streams in the process are required for the study. This information is shown Table 1. This shows the duties and temperatures associated with all of the heaters, coolers and process-to-process heat exchangers in Figure 1.

Note that there are heat loads associated with intermittent operations at the coke drums (e.g. steam out). These duties are omitted because in practice it is invariably uneconomic to include them in heat integration schemes (see discussion in Process Description).

Data Extraction: Utility Data

The bulk of the utility heating in the Delayed Coker comes from a furnace. In practice, and unless we plan to investigate possible changes in furnace design, we represent fired heaters for the Pinch analysis as heat sources at a single temperature that is hot enough to satisfy any anticipated heat load in the Unit. The remaining utility heating is provided by 9 barg steam, which is represented by a constant temperature utility at its saturation temperature (but see discussion in Step 1 above on steam pricing, and discussion below on steam generation specifics, for handling of sensible heat duties). The air-cooling and water-cooling likewise can each be represented as heat sinks at a single temperature.

	Heat Exchanger	Duty (MW)	Hot Side			Cold Side		
			Stream Name	Ts (°C)	Tt (°C)	Stream Name	Ts (°C)	Tt (°C)
E1	HGO Pumparound/T1 Reboiler	6.54	HGO Pumparound 1	338	286	T1 Reboiler	199	199
E2	Hot Tar Preheater	7.85	HGO Pumparound 2	338	295	Hot Feed	241	276
E3	Cold Tar Preheater	2.7	HGO Product	295	253	Cold Feed	169	274
E4	HGO Pumparound/9 barg Steam Generator	5.45	HGO Pumparound 3	295	245	9 barg Steam Generator	180	180
E5	HGO Air Cooler	8.06	HGO Product	253	132	Air	35	35
E6	HGO Water Cooler	3.69	HGO Product	132	77	Cooling Water	18	18
E7	T2 Reboiler	3.15	9 barg Steam	180	180	T2 Reboiler	104	105
E8	T2 Overhead Condenser	2.2	T2 Overhead	52	47	Air	35	35
E9	LGO Pumparound/9 barg Steam Generator	8.82	LGO Pumparound	258	188	9 barg Steam Generator	180	180
E10	T1 Overhead Condenser	4.72	T1 Overhead	59	48	Air	35	35
E13	T1 Bottoms Air Cooler	10.4	T1 Bottoms	199	69	Air	35	35
E14	T1 Bottoms Water Cooler	1.93	T1 Bottoms	69	44	Cooling Water	18	18
E15	LGO Product Cooler	3.34	LGO Product	258	51	Air	35	35
E17	Combination Tower Overhead Air Cooler	3.81	Combination Tower Overhead	96	69	Air	35	35
E18	Combination Tower Overhead Water Cooler	4.37	Combination Tower Overhead	69	38	Cooling Water	18	18
E19	Top Pumparound Air Cooler	5.6	Top Pumparound	138	91	Air	35	35
E20	Top Pumparound Water Cooler	6.65	Top Pumparound	91	35	Cooling Water	18	18
F1	Coker Feed Heater	39.51	Fired Heater	540	540	Coker Feed	363	496

Process Data (white) Utility Data (shaded)

Table 1: Summary of extended data from the existing Heat Exchanger Network

We also generate 9 barg steam using "waste heat" from the process. This steam generation requires a more detailed representation. Boiler feed water (BFW) is supplied at 107°C, and the steam is generated at 180°C. The heat for generating the steam therefore serves partly as sensible heat (314 kJ/kg between 107°C and 180°C), and the rest as latent heat (2,015 kJ/kg at a constant temperature of 180°C).

Steam Generation Specifics

If we represent 9 barg steam generation as a heat sink at a constant temperature, we would have to choose that temperature as 180°C. This implies that all of the heat (including the sensible heat) must be supplied at or above the saturation temperature. Many steam generation systems are in fact designed this way (for example, with cold boiler feed water being fed directly to a saturated steam drum). More than 13% of the heat is sensible boiler feed water (BFW) preheat that can be provided below the saturation temperature. Recognizing this fact allows us to use lower-temperature heat sources to perform the preheat function, thereby increasing the scope for steam generation.

To determine minimum energy consumption rigorously we need to represent the steam generation as a "segmented utility". The colder segment (107°C to 180°C) represents BFW preheat, and the hotter segment (at a constant 180°C) represents the latent heat.

The utility data for the Pinch study are summarized in Table 2. The annual costs shown here are based on the basic cost and efficiency data described above.

Utility	Temperature		Δh (kJ/kg)	Cost (CAN$/MW-year)
	Ts (°C)	Tt (°C)		
Furnace	540	540	n/a	178,000
9 barg Steam Consumption	180	180	2,015	142,000
9 barg Steam Generation	107 180	180 180	314 2,015	- 132,000*
Ambient Air	35	35	n/a	n/a
Cooling Water	18	18	n/a	n/a

* A negative cost means that steam generation reduces energy costs

Table 2: Utility Data Summary

Step 2: Generate Targets for Each Relevant Utility

Set ΔT_{min} value

In order to generate targets for minimum energy consumption we must first set the ΔT_{min} value for the problem. ΔT_{min}, or minimum temperature approach, is the smallest temperature difference that we allow between hot and cold streams in any heat exchanger, assuming counter-current flow.

This parameter reflects the trade-off between capital investment (which increases as the ΔT_{min} value gets smaller) and energy cost (which goes down as the ΔT_{min} value gets smaller). It is generally a good practice to analyse this trade-off quantitatively by using Pinch area targeting and capital cost targeting tools as presented in the *Pinch Analysis for the Efficient Use of Energy, Water and Hydrogen* guide and in a similar example produced by Natural Resources Canada for a Pulp and Paper process entitled *Energy Recovery and Effluent Cooling at a TMP Plant*. For the purpose of this example, typical ranges of ΔT_{min} values that have been found to represent the trade-off for each class of process have been used. Table 3 shows typical numbers that are appropriate for many refinery units, such as fluid catalytic cracking (FCC) units, coker units, crude distillation units, hydrotreaters and reformers.

In this study we take a ΔT_{min} value of 30°C, which is fairly aggressive for Delayed Cokers. This is applied to all process-to-process heat exchanger matches. Rather different trade-offs apply for heat transfer between process streams and utilities, so we typically define separate ΔT_{min} values for each utility.

Type of heat transfer	Experience ΔT_{min} values	Selected ΔT_{min} values
Process streams against process streams	30 - 40°C	30°C
Process streams against steam	10 - 20°C	10°C
Process streams against cooling water	10 - 20°C	10°C
Process streams against cooling air	15 - 25°C	15°C

Table 3: Experience and selected ΔT_{min} values

In the case of the furnace, as discussed in Step 1, we chose an arbitrary utility temperature (high enough to satisfy any heating duty in the FCC), and the ΔT_{min} value is similarly arbitrary.

For the 9 barg steam consumption and generation (including BFW preheating), however, we aim for a very close temperature approach (ΔT_{min} = 10°C). This reflects the fact that incremental duty in these services is generally cheaper to install than it would be for process-to-process services. Furthermore, for operability reasons designers prefer to provide ample steam generating capacity.

The ΔT_{min} chosen for air-cooling (15°C) is at the "tight" end of the range for air coolers, reflecting the fact that some of the existing air coolers in the example do have close temperature approaches. An even tighter approach (10°C) is assumed for water-cooling, as this is the coldest utility available and must be able to satisfy the lowest temperature cooling services.

Determine Targets

Having set the ΔT_{min} values, we can now proceed with targeting using data from Table 1. The results are shown in the form of Composite Curves (Figure 2), the Grand Composite Curve (Figure 3) and a summary table (Table 4).

The Composite Curves determine minimum hot and cold utility requirements and comparing this target with the existing utility consumption gives the scope for saving. The Grand Composite Curve provides targets for individual utilities and illustrates the effect of representing 9 barg steam generation as a segmented utility. The BFW appears as a diagonal line that meets the process Grand Composite Curve and the horizontal steam generation line at a Utility Pinch point. In this case, all of the heat input to the BFW is below this Utility Pinch point. If we had represented the steam with a single temperature corresponding to the saturation conditions we would have failed to identify the opportunity to recover any heat below the Utility Pinch point, and this would have resulted in a smaller 9 barg steam target.

The heat integration opportunities in the Coker Unit are best understood from the summary information in Table 4. The first two columns show the existing heat loads for each utility and the corresponding target loads. In the case of 9 barg steam generation these numbers include both the BFW and steam generation duties. The third column shows the scope for reducing each utility (existing load – target load). In the case of the 9 barg steam generation we gain credit for exporting the steam.

From Table 4 we can draw the following broad conclusions:

❶ The furnace duty is "on target". This is because the coker feed to fired heater F1 is the only process stream above the process Pinch – so there are no hot process streams at a high enough temperature to integrate with it and reduce the furnace duty.

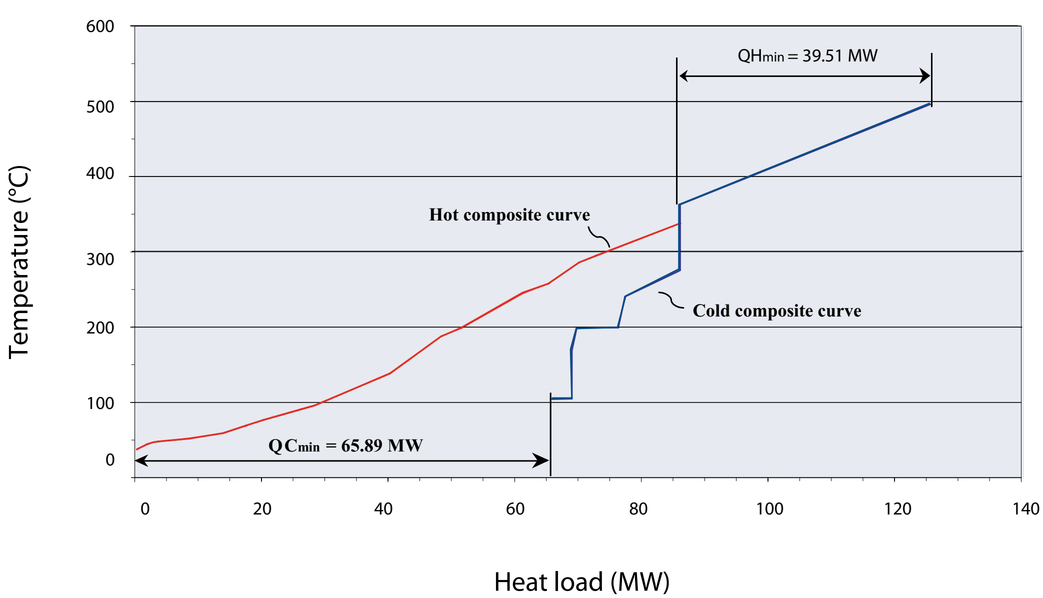
❷ The target for 9 barg steam consumption is zero. The only 9 barg steam user (E7, the T2 reboiler) should be replaced with a process-to-process service. This is worth $447,000/year.

❸ The 9 barg steam generation can be increased by up to 8.85 MW (a negative "Scope" means an increased duty). This is worth $1,168,000/year.

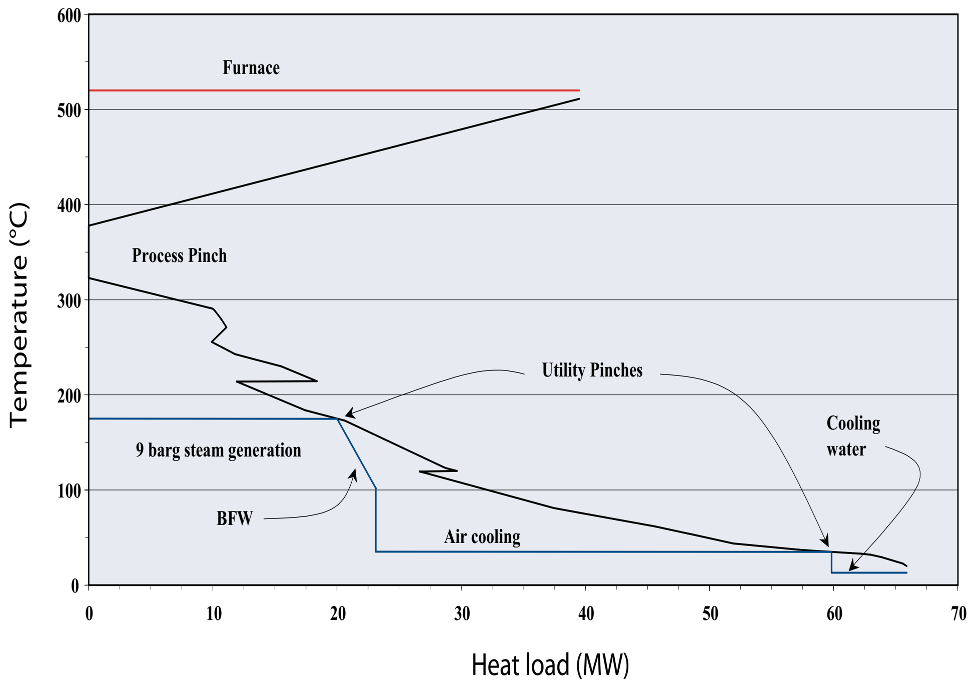
❹ We can shift 10.58 MW from cooling water to air-cooling. In practice the financial incentive for doing this is in the present case negligible, so we will not pursue this further.

Note: However, in new design situations there are often capital cost savings associated with maximizing air-cooling. Also, in some retrofit situations the cooling water system is a bottleneck. In these cases the cooling water/air-cooling trade-off should be explored further.

Figure 2 Composite Curves for Delayed Coker (ΔT_{min} = 30°C)



Grand Composite Curve for Delayed Coker **Figure 3**



	Existing (MW)	Target (MW)	Scope (MW)	Saving (CAN$/year)
Total hot demand	42.66	39.51	3.15	
Total cold demand	69.04	65.89	3.15	
Hot Utilities *Fired Heater*	39.51	39.51	0.00	0
9 Bar Steam Consumption	3.15	0.00	3.15	447,000
Cold Utilities				
9 Bar Steam Generation	14.27	23.12	-8.85*	1,168,000
Air	38.13	36.71	1.42	0
Cooling Water	16.64	6.06	10.58	0
Total				**1,615,000**

* A negative "Scope" means an increased duty

Table 4: Targets for Energy, Utilities and Existing Situation (Process ΔT_{min} = 30°C, Steam and Cooling Water ΔT_{min} = 10°C, Air Cooling ΔT_{min} = 15°C)

Step 3: Identify Major Inefficiencies in the Heat Exchanger Network

This step turns to design considerations. Most commercial Pinch software has tools to identify major inefficiencies and determine where heat is crossing each of the Pinches in a heat exchanger network (HEN) and violating Pinch rules (see *Pinch Analysis for the Efficient Use of Energy, Water and Hydrogen* guide). The results may be presented as a cross-Pinch summary table (Table 5) and/or as a grid diagram (Figure 4). Both provide substantially the same information, but in different formats.

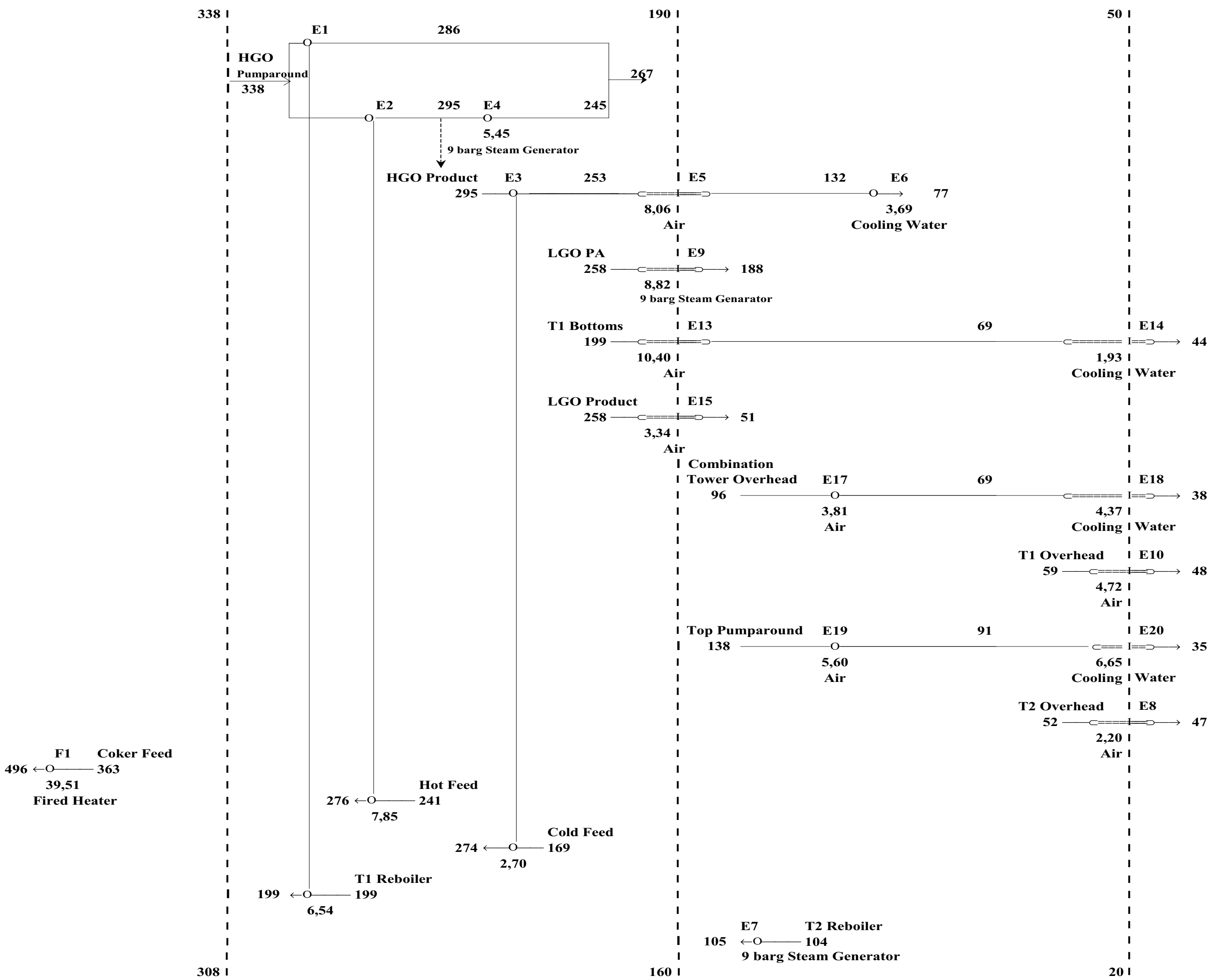
The grid diagram shows the supply and target temperatures (in °C) of all process streams, as well as the intermediate temperatures between heat exchangers. It also shows the hot and cold process stream temperatures corresponding to each of the Pinches, and identifies heat exchangers in which heat crosses a Pinch. Process-to-process heat exchangers are shown as "dumbbells", with circles on the hot and cold streams linked by a vertical line. Process-to-utility heat exchangers are identified by circles with the name of the utility underneath. Where a process stream within a heat exchanger extends across a Pinch the circles are elongated across the appropriate Pinch line. The overall heat load for each heat exchanger (in MW) is shown under the cold end of its dumbbell (or under the circle or elongated circle for utility heat exchangers).

Heat Exchanger		Hot Stream	Cold Stream	Pinch		
				Process	Utility	
					9 barg steam	Air
				323°C	**175°C**	**35°C**
E1	**HGO Pumparound/T1 Reboiler**	HGO Pumparound 1	T1 Reboiler			
E2	**Hot Tar Preheater**	HGO Pumparound 2	Hot Feed			
E3	**Cold Tar Preheater**	HGO Product	Cold Feed			
E4	**HGO Pumparound/9 barg Steam Generator**	HGO Pumparound 3	9 barg Steam Generator			
E5	**HGO Air Cooler**	HGO Product	Air		4.20	
E6	**HGO Water Cooler**	HGO Product	Cooling Water			3.69
E7	**T2 Reboiler**	9 barg Steam	T2 Reboiler		3.15	
E8	**T2 Overhead Condenser**	T2 Overhead	Air			-1.27*
E9	**LGO Pumparound/9 barg Steam Generator**	LGO Pumparound	9 barg Steam Generator		-0.28*	
E10	**T1 Overhead Condenser**	T1 Overhead	Air			-0.87*
E13	**T1 Bottoms Air Cooler**	T1 Bottoms	Air		0.71	
E14	**T1 Bottoms Water Cooler**	T1 Bottoms	Cooling Water			1.50
E15	**LGO Product Cooler**	LGO Product	Air		1.10	
E17	**Combination Tower Overhead Air Cooler**	Combination Tower Overhead	Air			
E18	**Combination Tower Overhead Air Cooler**	Combination Tower Overhead	Cooling Water			2.66
E19	**Top Pumparound Air Cooler**	Top Pumparound	Air			
E20	**Top Pumparound Water Cooler**	Top Pumparound	Cooling Water			4.87
F1	**Coker Feed Heater**	Fired Heater	Coker Feed			
Total					**8.88**	**10.58**

*: A negative cross-pinch duty in any heat exchanger means that the minimum temperature difference between the cold and the hot stream in this heat exchanger is less than the specified ΔT_{min} for its application (see Table 3).

Table 5: Cross-Pinch Summary

Figure 4 Grid Diagram of the Heat Exchanger Network



Our primary concern at this stage is to identify the main inefficiencies at each of the Pinches:

- ❖ There are no duties crossing the process Pinch. This is because the coker feed to fired heater F1 is the only process stream above the process Pinch. There are no hot process streams at a high enough temperature to integrate with it and reduce the furnace duty, and the furnace duty is "on target", as previously noted.

- ❖ The Utility Pinch at 175°C interval temperature (hot process stream temperature of 190°C usually at the top of the diagram, cold process stream temperature of 160°C at the bottom of the diagram) corresponds to the point where the diagonal BFW line and the horizontal steam generation line meets the grand composite curve in Figure 3. The total cross-Pinch duty is 8.88 MW, and the largest single inefficiency is in E5, the HGO air cooler (4.2 MW). This portion of the HGO heat can be upgraded from air cooling to 9 barg steam generation.

  The next largest cross-Pinch duty is in E7, the T2 reboiler. This reboiler is currently using 9 barg steam, but as the process temperature is only ~105°C the heat can be provided by a process stream below 175°C Pinch (9 barg steam Pinch). We should not use a process stream above the Pinch, or we will reduce the scope for 9 barg steam generation.

  Heat also crosses this Pinch in E15 (LGO Product Cooler) and E13 (T1 Bottoms Air Cooler). The amounts of heat are comparatively small (1.10 MW and 0.71 MW, respectively). However, conceptually it would be very simple to install new 9 barg steam generators to recover this heat, in the same way we can generate steam from the HGO Product.

- ❖ The duties crossing the air-cooling Pinch at 35°C interval temperature (hot process stream temperature of 50°C, cold process stream temperature of 20°C) show where opportunities exist to shift cooling water loads to air-cooling. However, as we have already noted, there is no incentive to make this load shift. Of much greater importance is the opportunity to recover heat between the 175°C Pinch and the 35°C Pinch to preheat BFW and to reboil T2. From the grid diagram (Figure 4) it is apparent that the best streams to consider for these services are HGO Product, LGO Product, and T1 Bottoms. In all three cases heat is rejected from these streams in the appropriate temperature range in air coolers (E5, E15 and E13, respectively).

Step 4: Define Options for Reducing or Eliminating the Largest Inefficiencies

During the targeting phase (Step 2) we established the magnitude of the potential opportunity for energy savings. In network analysis (Step 3) we identified the specific inefficiencies in the existing HEN. We now turn our attention to correcting the inefficiencies in order to approach the target energy usage in practice.

It is rarely practical or economic to eliminate every inefficiency in a HEN. Attempting to do so usually leads to unreasonably complex designs. The approach to take, therefore, is to focus on the largest inefficiencies that we identified in Step 3. In this case there are three types of opportunities to consider:

- Add 9 barg steam generators
- Use a process stream (below the 175°C Utility Pinch) to reboil T2
- Add a BFW preheater to increase 9 barg steam production

For all three of these types of opportunities there are three different possible heat sources to consider, namely:

- HGO Product
- LGO Product
- T1 Bottoms

The selection of the most interesting options is not directly apparent from the Pinch targeting results. In general, at this point there is no alternative to a technical and economic comparison of the options that have been identified and the use of commercial Pinch software is very useful.

Step 5: Evaluate Competing Options

In any heat exchanger network each change we make in any given heat exchanger is likely to have knock-on effects on other heat exchangers. Some of the commercially available Pinch software packages incorporate tools for estimating these effects. Either way, we require some type of model to quantify the utility savings attributable to each option and combination of options we wish to evaluate. In this example, the opportunities identified in Step 4 are comparatively simple to evaluate, as there are no knock-on effects to consider between heat exchangers in the existing heat exchanger network. All we need to do is:

- ❖ Quantify the utility savings attributable to each option and combination of options we wish to evaluate. These utility savings are converted to monetary savings using the utility costs data in Table 2.

- ❖ Estimate the cost of implementing each option. Most often this involves estimating the size and cost of heat exchangers. We can generally obtain estimates of the heat transfer coefficients for new shells from the data sheets of the existing heat exchangers, and with this information we can estimate the area of any new shells. Rough cost estimates can then be obtained from simple "rule of thumb" correlations – e.g.,

  Installed Cost (CAN$)= 2,000 x Area ($m^2$)

- ❖ The cost of piping and any other equipment required for the identified options can be estimated in similar ways[3].

- ❖ When we have the cost and savings numbers for an option we can calculate the simple payback (cost/annual savings), or compute other measures of value such as ROI or NPV. Any of these measures can be used to quantify the attractiveness of each option. The way this is done generally depends on the preferences of the sponsor of the study. In the present example, the criterion used is that each project must achieve a simple payback of less than two years.

Step 6: Select the Best Option or Combination of Options

The changes incorporated in the process as a result of the evaluation described in Steps 4 and 5 are summarized in Table 6, and the final design is shown in Figure 5. The specific changes are as follows:

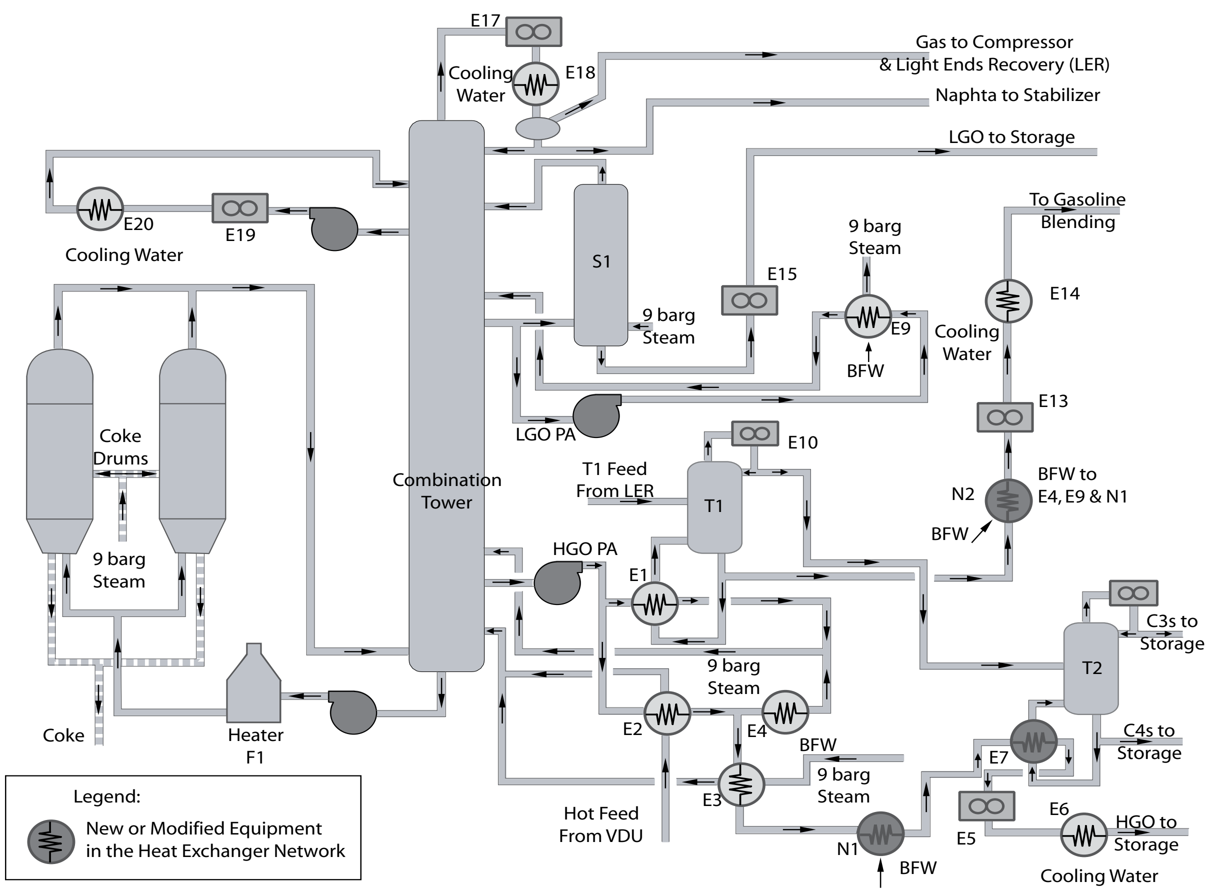
❶ Add a new 9 barg steam generator N1 on the HGO Product. This recovers 4.2 MW, worth CAN$ 554,000/year, with an investment of CAN$ 874,000, giving a simple payback of 1.6 years. The other steam generator options (LGO Product and T1 Bottoms) fail to achieve the 2 year simple payback requirement.

❷ Use the HGO Product after N1 to drive the T2 reboiler. We can use the existing shell (E7), but we must replace the tube bundle to handle the new heating medium. There is also some added cost due to piping. This project saves 3.15 MW of 9 barg steam, worth CAN$ 447,000/year, with an investment of CAN$ 328,000, giving a simple payback of nine months. One key aspect of this project is that it ties the operation of T1 to the HGO Product, whereas in the existing design T1 can be operated independently.

[3] Ideally any correlations of this type should be agreed with cost estimators at the site for which the study is being performed, as site-specific factors often come into play. However, in the absence of this input it is generally possible to generate sufficiently accurate cost correlations using published data.

❸ Add a BFW preheat exchanger N2 using T1 Bottoms as the heating medium. This heats the BFW for the two existing 9 barg steam generators (E4 and E9) and the new 9 barg steam generator (N1) to 165°C. This is 15°C below the saturation temperature, because of concerns about possible vaporization in the BFW lines and valves. The new shell recovers an additional 2.22 MW for incremental 9 barg steam generation, which is worth CAN$ 292,000/year, with an investment of CAN$ 438,000, giving a simple payback of 1.5 years.

Figure 5 Simplified Flowsheet of the Delayed Coker Unit Showing Selected Projects



Id	Project Description	Duty (MW)	Credit (CAN$/year)	Investment (CAN$)	Payback (year)
❶	**HGO Steam Generator (N1)**	4.20	554,000	874,000	1.6
❷	**HGO/T2 Reboiler (E7)**	3.15	447,000	328,000	0.75
❸	**T1 Bottoms/BFW Preheat (N2)**	2.22	292,000	438,000	1.5
	Total	**9.57**	**1,293,000**	**1,640,000**	**1.3**

Table 6: Selected Projects

Overall these changes save 3.15 MW in 9 barg steam use and recover 6.42 MW for additional 9 barg steam generation (9.57 MW total), worth CAN$ 1,293,000/year. These results compare with a target 9 barg steam saving of 3.15 MW and a target increase of 8.85 MW in heat recovery for 9 barg steam generation (12.00 MW total), with a net monetary target saving of CAN$ 1,615,000/year (see Table 4). The selected design therefore achieves about 80% of the target savings for both energy and money. It does not achieve 100% of the savings because:

❖ We could not correct the cross-Pinch duties on the LGO Product and T1 Bottoms at the 175°C Pinch within the 2 year simple payback requirement

❖ The BFW preheat temperature in the final design is 165°C, not the 180°C used in targeting

CONCLUSIONS

Pinch Analysis is a very powerful technique to identify minimum energy consumption targets for heating and cooling and to identify projects that will allow significant energy savings. In this example we identified three different types of projects that are commonly found in Pinch studies – new opportunities for process-to-process heat integration (HGO Product/T2 Reboiler), new steam generators (HGO Product/9 barg steam generation service N1), and boiler feed water preheating (T1 Bottoms/BFW service N2).

This example also highlights an important fact about Pinch analysis. Properly calculated Pinch targets are always thermodynamically achievable, and we try to select ΔT_{min} values that will ensure the targets are economically realistic. However, achieving savings requires not just targets, but actual projects. In most cases, practical process constraints limit the economically attainable project savings to a value that is somewhat less than the target savings. This does not invalidate Pinch targets – it simply illustrates that they are best understood as guidelines, not absolutes.

The CanmetENERGY research centre in Varennes is one of three research and innovation centres of Natural Resources Canada (NRCan). CanmetENERGY in Varennes designs and implements technological solutions, and disseminates knowledge in order to produce and use energy in ways that are more efficient and sustainable, to reduce greenhouse gas (GHG) and other air emissions, and to improve innovation capabilities of targeted sectors of the Canadian economy.

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