Integration of Electric Boilers in a Utility System with Cogeneration: Sines Refinery Case Study

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Abstract

The increase in primary energy consumption over the last few years, mainly fossil energy in emerging countries, has put environmental issues at the center of the discussion. The introduction of the Paris Agreement and the rise in carbon taxes, requires the introduction of flexibility options in combined production units of steam and electricity. In this work, we identify and suggest flexibility options for the cogeneration system of the Sines refinery. A simulation model was developed using the Aspen Plus software and validated with real operational data. Next, flexibility alternatives were identified aiming to reduce CO_2 emissions, through the regulation of the natural gas supply and the elimination of the post-combustion system of the recovery boilers. In this framework, the introduction of electric boilers to compensate for the refinery's steam needs was evaluated (centralized high-pressure boilers at 83barg or decentralized medium/low pressure boilers at 3.5 and 24barg). In all simulations, lower natural gas flaring increases electricity imports. For such flexibility options, we studied the economic feasibility and calculated the threshold electricity prices (below which profit is possible). The prices ranged between 25€ and 42€ per MWh. Finally, the integration of solar and wind energy to minimize electricity imports and maximize economic profitability was considered.

Keywords: Cogeneration, Flexibility, CO_2 Emissions, Natural Gas Consumption, Electricity Prices.

1. Introduction

Primary energy consumption has increased considerably over the past few years, from just over 9.500 Mtoe (million tonnes of oil equivalent) in 1998 to around 14.000 in 2018 [1]. This is partly due to the increase in the consumption of primary fossil energy in emerging countries, which see it as an inexpensive option to improve the life quality of their populations. Over the next two decades, fossil fuels are expected to continue to account for the production of around 60% of the energy consumed worldwide [2]. With the increase in primary energy consumption, there is a natural increase in greenhouse gas emissions, mainly carbon dioxide. It is currently a matter of utmost importance globally, represented by the entry into force of the Paris Agreement, which aims to prevent an average increase in global temperature below 2ºC at the end of the century (compared to pre-industrial levels). As a result of the targets of the Paris Agreement and with the aim of fostering greater integration of renewable energies [3], an increase in the price per tonne of CO_2 emitted is expected. Galp's cogeneration unit in Sines is responsible for the emission of about 500.000 tonnes of CO_2 annually. In the current context, the board of directors finds it urgent to explore operational flexibility options to ensure the supply of electricity and heat (in the form of steam), with the greatest economic and environmental efficiency.

In [4], a techno-economic study was carried out in order to quantify the impact that different forms of operational flexibility (by changing the natural gas inlet flowrates) and product flexibility (through a bypass to the turbogenerators, allowing the integration of power-to-heat technologies, such as electric boilers [5], and integration of renewable energies into the system, such as solar and wind [6]) have on a cogeneration unit whose operational model is designed to meet steam needs. The authors concluded that product flexibility presents much more promising results than operational flexibility, being a more advantageous option mainly for lower electricity prices.

In [5] and [7], studies were carried out with the objective of increasing the flexibility of a cogeneration unit through the integration of electric boilers into a district heating system. Both conclude that the integration of

electric boilers allows not only a reduction in operating costs, but also contributes to the integration of renewable energy (wind) in the system.
This paper aims to identify and suggest flexibility options applicable to the refinery's cogeneration unit and evaluate their economic viability. To achieve this goal, we developed a representative model of the cogeneration unit in Aspen Plus, using operational data and information contained in the equipment specification sheets. The model was validated by adjusting the simulation results (mainly electricity and steam production) with the actual results of the refinery. With this model, it is possible to identify and suggest options of operational and product flexibility. The economic profitability of the various options is obtained for the current CO_2 and natural gas prices.
Overall, this paper aims to contribute to a new operational strategy of the refinery, one achieving decarbonization without jeopardizing profit.

2. Industrial System under Study

The cogeneration system at Sines refinery, inaugurated in 2009, combines steam and power production (Brayton and Rankine cycles [8]), supplying high pressure steam by burning natural gas.
It consists of:

- Two natural gas turbines (GT1 and GT2) continuously generating 41MW of electric power;
- Two aqua-tubular recovery boilers (BR1 and BR2), equipped with natural gas and fuel gas afterburners, allowing the production of 125 ton/h of overheated steam at 83barg and 523ºC;
- Two aqua-tubular conventional boilers (CE-BF 2 and 4).

All steam produced is sent to a collector and subsequently distributed to the following consumers:

- High pressure turbopumps responsible to feeding water to boilers;
- Reducing valves;
- Turbogenerators for generating electricity.

Thus, in addition to the steam at 83barg, there are other ranges of overheated steam:

- 24bar and 380ºC;
- 10.5bar and 320ºC;
- 3.5bar and 220ºC.

3. Modelling the Cogeneration System

The cogeneration unit was modeled in software AspenPlus V11 as an independent system with steam and electricity demand from the refinery.

3.1 Gas Turbines (GT1 and GT2)

The process begins with the capture of ambient air in the turbines, through highly effective filters. Subsequently, the air is compressed to the desired pressure. In the combustion chamber, the compressed air is mixed with high-pressure natural gas, generating various combustion reactions. The combustion gases, at high pressure and temperature, are then driven to the turbine, where they are expanded, leading to the generation of electricity.
The modeling of gas turbines in Aspen Plus is done using one valve, one compressor, a combustion chamber (defined as *Rstoic* reactor, with a 100% conversion) and a turbine, as can be seen in Figure 1.

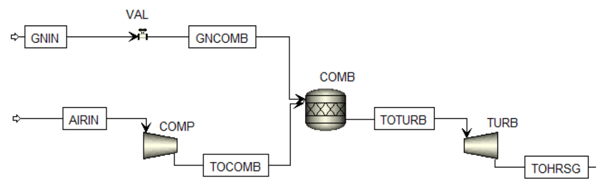


Figure 1 - Gas Turbine Modeling in Aspen.

The compressor and turbine modules for the gas turbine, require the user to specify thermodynamic and mechanical efficiencies. These efficiencies were estimated using real data of electricity production and exhaust gases temperature, leading to the values in Table 1. Both efficiencies were obtained using the compressor/turbine model of the polytropic type, since it was the model that proved to have the best fit against the results obtained compared to the actual refinery data. The data point chosen was 1/1/2020 at 0:00, once there are no significant variations throughout the year, for the gas turbine operation. As can be seen in Table 2, the error is below 0.5%, being within the 5% error margin given by Galp.
It is important to note that since the two gas turbines are similar, the model developed applies to both.

Table 1 - Compressor and turbine efficiencies values (GT1-2).

Data	**Value**
COMP Efficiency (%)	85.56
TURB Efficiency (%)	88.41
TURB mechanical efficiency (%)	93.16

Table 2 - Comparison between real and estimated values (GT1-2).

Temperature (ºC)			**Power** (MW)		
Aspen	Real	Deviation (%)	Aspen	Real	Deviation (%)
554.48	551.53	+0.50	40.93	40.80	+0.32

3.2 Recovery Boilers (BR1 and BR2)

After expansion in the gas turbine, the exhaust gases, with a temperature of about 550ºC, are driven to the recovery boilers. In there, heat is transmitted, by convection, between the exhaust gases and the water circulating inside the tubes of the heat exchangers, producing high pressure steam. As seen in Figure 2, the recovery boiler is composed of several heat exchangers, each with a specific function. The boiler is equipped with a fuel burning system (*COMB2*, defined, once again as a *Rstoic* reactor with 100% conversion), enabling to increase steam production by burning more natural gas.

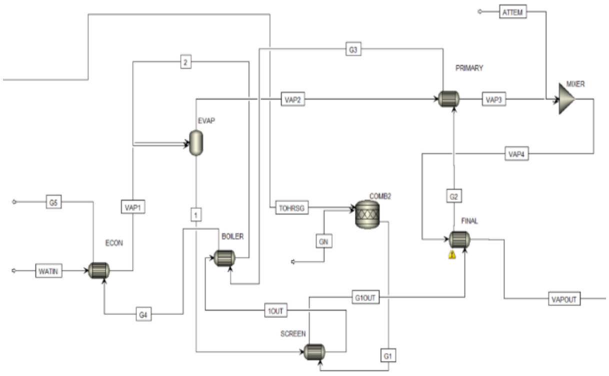


Figure 2 – Recovery Boiler modelling in Aspen.

The modeling of the recovery boilers was carried out based on the equipment specification sheet [9], which provides values for four steam flowrates (105, 110, 125 and 137.5 ton/h). To make it possible to simulate for other flowrates, we changed the mode of the heat exchangers to *simulation*, which, according to the Aspen software manual, allows to calculate, in a real way and, through the heat transfer area and input fluids, the conditions at the equipment outlets. It is necessary to specify the heat transfer area (A) and the overall heat transfer coefficient (U). For A, we used the value given in the specification sheet. On the other hand, the overall heat transfer coefficient, according to [10], will depend directly on the flow of fluid circulating inside the pipes. Therefore, while the area value is constant for all simulations, the value of the overall heat transfer coefficient varies with the flow of vapor that is intended to be produced. In this sense, simulations were performed, with *design* mode, for the steam flows described in the equipment specification sheet, in order to obtain the value of the overall heat transfer coefficient in each heat exchanger. To avoid simulation errors in Aspen, it is necessary to, iteratively perform simulations with the alternating placement of heat exchangers in *simulation* mode and in *design* mode. The final modeling obtained, together with the characteristics of each heat exchanger, is summarized in Table 3.

Table 3 – Heat exchangers modelling in Aspen.

Heat Exchanger	A (m^2)	U ($W/m^2.K$)	Mode	Condition
Economizer (*ECON*)	32604	25	Design	Water exits at 298ºC
Boiler (*BOILER*)	16812	25	Design	Vapor fraction = 1
Primary Superheater (*PRIMARY*)	2521	65	Simulation	-
Final Superheater (*FINAL*)	999	43	Simulation	-
Screen (*SCREEN*)	316	23	Simulation	-

3.3 Vapor Turbines (TG3, TG4 and TG5)

The refinery has 4 turbogenerators (TG2,3,4 and 5), however TG2 is currently out of service [8]. TG3 and TG4 are similar and so were modeled as a single turbogenerator. In their 1st stage, the steam produced feeds the 3.5bar collector. The low-pressure steam that is generated in the 2nd stage is then condensed. In contrast, the vapor produced in the 1st of TG5 feeds the 24bar collector, with the vapor generated in the 2nd stage being fed into the 3.5bar collector [11]. Note that the two stages of each turbogenerator were modeled as two independent turbines, as can be seen in Figure 3.

Initially, the turbogenerator modeling strategy was like the strategy used in modeling gas turbines (GT). However, as stated earlier, there are no significant variations for the operation of gas turbines during the year. On the other hand, the operation mode of TGs is controlled by the refinery's steam needs. The strategy used for model validation was to perform a simulation for each turbogenerator, for a date/hour when the production of electricity corresponds to an average value throughout the year.

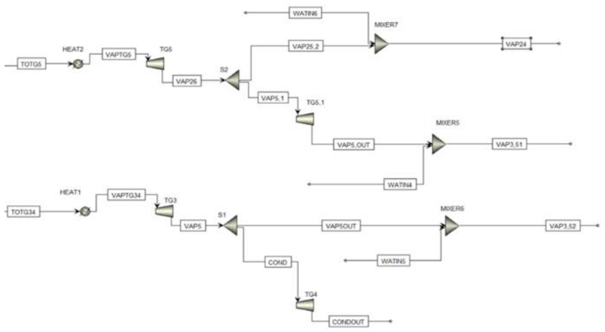


Figure 3 - Turbogenerator modelling in Aspen.

Thus, it was possible to obtain the efficiencies corresponding to each stage of the turbine and, maintaining these values, new simulations were carried out for several dates/hours throughout the year, to be able to verify whether the modeling of the turbogenerators fits the reality. The results given by the simulations do not correspond to the values verified in the refinery, presenting deviations higher than the possible errors associated with the measuring instruments and to the 5% given as margin. Therefore, it is not possible to keep the efficiencies constant, being necessary to adjust the efficiencies for different steam flowrates. In other words, the model for turbogenerators is not as robust.

3.4 Reducing Valves (REDT)

The high-pressure steam produced in the recovery boilers can be fed to the refinery's reducing valve group. This is an alternative way to produce steam at the different desired pressure levels, one leading to higher temperatures. At the Sines refinery, there are 3 types of reducing valves [8]:

- Reducing valve from 80 to 25 bar (REDT25);
- Reducing valve from 24 to 10.5 bar (REDT10);
- Reducing valve from 24 to 5 bar (REDT5).

Figure 4 shows the group of reducing valves in Aspen:

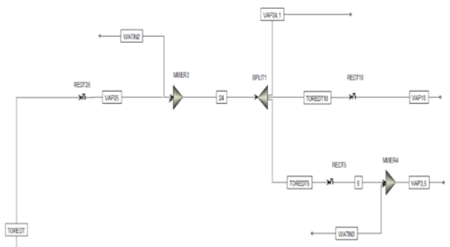


Figure 4 - Reducing valves modelling in Aspen.

3.5 Turbopumps (CE-P)

Finally, part of the high-pressure steam produced in the recovery boilers is sent to the CE-P6 and CE-P9 turbopumps, which are coupled to a turbine. When passing through the turbine, the expanded steam will trigger the generator, providing electricity for operating of the pumps [8]. Thus, the modules in Aspen were not the pumps themselves, but their associated turbines, the equipment belonging to the steam cycle (Rankine cycle). As both pumps operate similarly, output pressure of 25 bar, only one turbine was modelled (Figure 5). The efficiency was adjusted so that the steam outlet temperature was approximately 380ºC, leading to a value of 60%.

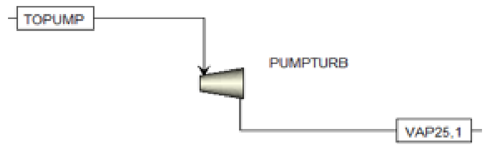


Figure 5 - Turbopumps modelling in Aspen.

Thus, the modeling in Aspen, of the cogeneration unit of Sines refinery is completed, and it is possible to study flexibility options discussed below.

4. Results and Discussion

To reduce carbon emissions, two options are available:

- Decrease the supply of natural gas to recovery boilers (BR1 and BR2);
- Decrease the supply of natural gas to the gas turbines (GT1 and GT2).

Both options will be studied next.

4.1 Flexibility in Recovery Boilers

The operating mode of recovery boilers, turbogenerators, reducing valves and turbopumps is controlled by the refinery's steam needs. Specifically, the elimination of the post-combustion system limits the production of steam to 70 ton/h, at about 480ºC. This will affect both the quantity and quality of steam that is supplied to the clients of the utility plant, the other plants in the refinery. To overcome this problem, it will be necessary to introduce power-to-heat technologies, like electric boilers. The elimination of the afterburner system of one or two recovery boilers can be compensated in two different ways:

- **Simulation 1** - Introduction of an 83barg electric boiler; the steam is supplied to the high-pressure collector of the refinery (mixed with the steam produced in the other boilers); there are no changes to the normal operation of the cogeneration unit.
- **Simulation 2** - Introduction of 3.5 and 24barg electric boilers; the steam fed to the high-pressure collector will be lower and, as the steam turbines are sensitive to changes in the flowrate and temperature of the steam, this option discards the use of turbogenerators; it limits the use of high-pressure steam to reducing valves and turbopumps.

It is important to note that an electric boiler can only produce saturated steam, which means that will be necessary to integrate a superheater in order to produce steam in the conditions desired by the refinery.

In each simulation, we consider two scenarios: without supplementary firing in one recovery boiler (Simulation 1.1 and 2.1) and in both (Simulation 1.2 and 2.2).

4.1.1 Simulation 1 vs Simulation 2

To determine which configuration is more advantageous, not only in terms of electricity production and quantity/quality of steam produced, but also in the economic level associated with the decrease in natural gas consumption and CO_2 emissions, 9 simulations were performed for different dates/hours throughout the year.

For January 1st at 0:00, the simulation results are summarized in Table 4 (the same trend was observed in simulations for different days). As can be seen, all options lead to a major increase in electricity imports by the refinery. This happens not only because of the increase in electricity consumption due to the integration of electric boilers, but also due to the non-use of turbogenerators (in the case of simulation 2). Therefore, before making any kind of evaluation to understand which of the two options is more advantageous, it will be necessary to evaluate the profitability of each one. In this sense, it is important to calculate the electricity price that allows each configuration to be profitable. This price is calculated from equation 1, where we have used the following prices:

- Natural gas: 250€/ton;
- CO_2: 50€/ton.

$$Electricity\ Price = \frac{\Delta_{\ Consumption\ GN} \times Price_{GN} + \Delta_{Emission\ CO2} \times Price_{\ CO2}}{\Delta_{\ Electricity\ Imports}} \quad \textbf{(1)}$$

$\Delta_{\ Consumption\ GN}$ represents the variation in natural gas consumption, $\Delta_{Emission\ CO2}$ refers to the variation in CO2 emissions and $\Delta_{\ Electricity\ Imports}$ represents the variation in electricity imports. All variations are relative to the base case.

Applying the values from to equation 1, we obtain:

- **Simulation 1.1** = 21.76 €/MWh
- **Simulation 1.2** = 21.10 €/MWh
- **Simulation 2.1** = 26.96 €/MWh
- **Simulation 2.2** = 23.44 €/MWh

Table 4 - Simulations 1 and 2 results for January 1st at 00am.

Case	Imported Electricity (MW)		Natural Gas Consumption (ton)				CO₂ emissions (ton)			
	Imported Electricity	Difference to the Base Case (Δ)	Gas Turbines (GT1 e GT2)	Recovery Boilers (BR1 e BR2)	Total	Difference to the Base Case (Δ)	Cogeneration 1	Cogeneration 2	Total	Difference to the Base Case (Δ)
Base Case	34.53	-	19.15	4.23	23.38	-	32.49	32.17	64.66	-
Simulation 1.1	72.33	+37.80	19.15	2.11	21.27	-2.12	26.64	32.17	58.78	-5.85
Simulation 1.2	112.36	+77.83	19.15	0	19.15	-4.23	26.64	26.33	52.97	-11.69
Simulation 2.1	65.04	+30.51	19.15	2.11	21.27	-2.12	26.64	32.17	58.78	-5.85
Simulation 2.2	104.59	+70.06	19.15	0	19.15	-4.23	26.64	26.33	52.97	-11.69

It is noticeable that the results obtained for simulation 2 are more promising than the results obtained in simulation 1. This conclusion is interesting, since simulation 2 does not involve the use of the TGs, thus losing the electricity produced by them. It can be explained by the electrical power required to run the superheater of the electric boiler. As in simulation 1 more superheating of the steam is required, the electricity consumption will be higher.

Now that we know what is the limit price of electricity that allows to obtain a profit for each simulation performed, it remains to be seen what the effective profit is (if any) given a certain value for the price of electricity.

The profit obtained in each simulation is given, as a function of the electricity price, by equation 2:

$$Profit = (\Delta_{Consumption\ GN} \times Price_{\ GN} + \Delta_{Emission\ CO2} \times Price_{\ CO2}) - (\text{Electricity Price} \times \Delta_{Electricity\ Imports}) \quad \textbf{(2)}$$

Table 5 shows the profit obtained for each simulation by applying different electricity prices. The simulations that prove to be most profitable for each price are shown in green.

It is important to mention that the pattern presented in Table 5 was obtained for 8 of the simulated dates/hours, in a total of 9. Within the simulated dates/hours, only for September 10th at 20:00 a different pattern was obtained, being 1.1 and 1.2 the most profitable simulations, even though with values very close to simulations 2.1 and 2.2. However, it is important to note that for this specifically day and hour, TG3 and TG4 were out of service, which may help explain this difference.

As discussed earlier, simulations 1 and 2 do not present any difference with respect to the refinery's steam production, representing only alternative options for achieving it. Therefore, they can only be distinguished based on electricity production (by turbogenerators)

Table 5 - Profit obtained for each simulation according to the price of electricity (January 1st at 00am).

Date	Electricity Price (€/MWh)	5	10	15	20	21	24	25
1/1 00h	1.1	633	444	255	66	28	-84	-122
	1.2	1252	863	474	85	8	-225	-303
	2.1	669	517	364	212	181	90	59
	2.2	1291	941	591	240	170	-39	-109

and consumption (by electric boilers). It is therefore possible to conclude that the results obtained are more favorable to simulation 2, both in electricity price limit and in profit obtained.

Although the conclusions are extremely favorable in relation to simulation 2, it is important to mention that in the case of May 8th at 7:00, it was not necessary to use electric boilers in simulation 2.1, even when eliminating the supplementary firing in BR1. Therefore, the group of reducing valves was perfectly capable of producing all the necessary steam at the various pressure levels. It happens, because the steam production in the recovery boilers was quite low, below the minimum limit of 105ton/h given by the equipment specification sheet. In this sense, it might be profitable to backtrack a little on the model developed and change the operation mode of the gas turbine (GT1), reducing the supply of natural gas, which will necessarily cause a decrease, not only in flow, but also in the enthalpy of the exhaust gas stream that is subsequently fed to the recovery boiler (BR1), leading to reduced steam production.

Therefore, a third type of simulation was used, which will be discussed next.

4.2 Flexibility in Gas Turbines

4.2.1 Simulation 3

In Simulation 3, we intend to study the consequences of changing the operation of the gas turbine on steam production and on the refinery's, electricity needs, as well as to calculate its profitability. Note that due to contractual agreements, all the electrical energy generated in the cogeneration units gas turbines must be exported to the grid. In other words, by changing the operation of the turbines, there will be a consequent decrease in the production of electrical energy, which will necessarily lead to a decrease in exports. Therefore, the objective of simulation 3 is to understand if the decrease in natural gas consumption and consequent decrease in CO_2 emissions is enough to compensate for this loss. Although the simulation of May 8th at 7:00 was previously discussed, the truth is that the normal steam production by the recovery boilers is lower than the minimum limit referenced in the specification sheet. In this sense, for Simulation 3, we used June 4th at 8:00, when cogeneration unit 1 precisely produces the value of 105 ton/h, as can be seen in Table 6.

Table 6 - Steam conditions produced in BR1, BR2 and BF4 on June 4th at 08am.

Equipment	Flow (ton/h)	Temperature (ºC)
Recovery Boiler BR1	105.02	521
Recovery Boiler BR2	99.13	523
Boiler BF4	0	-

In order to test the impact of a possible change in the way the gas turbines operate, the following simulations were performed:

- **Simulation 3.1** - GT1 at 80% and no TG, regulating the natural gas to be fed to the BR1 afterburner system to produce all the steam required;
- **Simulation 3.2** - No afterburner system at BR1 and no TG - Obtain the minimum natural gas feed to GT1 needed to produce all the steam;
- **Simulation 3.3** - With afterburner system at BR1 and no TG - Obtain the minimum natural gas feed to GT1 needed to produce all the steam.

Simulations 2.1 and 2.2 were also performed since they were the two simulations that obtained the best results in the previous profitability analysis. In this sense, it becomes pertinent to compare with the results of simulations 3.1, 3.2 and 3.3, to find the most profitable operating mode. The results obtained are presented in Table 7.

Analogously to what was done for simulations 1 and 2, it is necessary to calculate what is the limit price of electricity that allows a profit to be made. However, the price will not be given by equation 1, since it is necessary to include the decrease in exports of electricity produced in gas turbines. The contractual price for the sale of electricity was shared by Galp, with a value of 57€/MWh. Thus, the price of electricity will be given by:

$$Electricity\ Price = \frac{\Delta_{Con.GN} \times Price_{GN} + \Delta_{Emi.CO2} \times Price_{CO2} - \Delta_{Elec.Prod.} \times Price_{\ Sales}}{\Delta_{Electricity\ Imports}} \quad \textbf{(3)}$$

Table 7 - Simulations 2 and 3 results for June 4th at 08am.

Case	Exported Electricity (MW)		Imported Electricity (MW)		Natural Gas Consumption (ton)		CO_2 emissions (ton)	
	Exported Electricity	Difference to the Base Case (Δ)	Imported Electricity	Difference to the Base Case (Δ)	Total	Difference to the Base Case (Δ)	Total	Difference to the Base Case (Δ)
Base Case	75.81	-	-7.11	-	21.25	-	58.76	-
Simulation 3.1	68.24	-7.57	14.63	+21.74	17.77	-3.48	49.13	-9.63
Simulation 3.2	70.14	-5.67	14.63	+21.74	18.08	-3.17	49.99	-8.77
Simulation 3.3	50.44	-25.37	14.63	+21.74	15.11	-6.14	41.76	-16.97
Simulation 2.1	75.81	0	14.63	+21.74	19.45	-1.80	53.79	-4.97
Simulation 2.2	75.81	0	32.55	+39.66	18.14	-3.11	50.18	-8.58

$\Delta_{Elec.Prod.}$ represents the variation of electricity production in GT in relation to the base case.

By equation 3 the limit price that allows profitability is calculated. The results obtained are:

- **Simulation 3.1** = 42.32 €/MWh
- **Simulation 3.2** = 41.76 €/MWh
- **Simulation 3.3** = 43.12 €/MWh
- **Simulation 2.1** = 32.13 €/MWh
- **Simulation 2.2 =** 30.42 €/MWh

As it is possible to verify, all simulations performed for simulation 3 present a higher electricity price limit than simulation 2. However, as observed previously, the fact that the electricity price limit is higher does not necessarily mean that this option will be the most profitable. Therefore, it is important to understand, again, what is the profit obtained for each simulation, given a value of electricity price. In this sense, the profit can be calculated by equation 4:

$$Profit = (\Delta_{Con.\,GN} \times Price_{\,GN} + \Delta_{Emi.\,CO2} \times Price_{\,CO2}) - (Electricty\ Price \times \Delta_{Elec.Imports} + Price_{Sales} \times \Delta_{Elec.Prod.}) \quad \textbf{(4)}$$

Table 8 shows the profit obtained for each simulation when applying different electricity prices. When analyzing Table 8, it is noticeable that for lower electricity prices, simulation 2.2 is the most profitable (like it was seen in the comparison between simulations 1 and 2). However, for higher electricity prices, simulation 3.3 becomes the most profitable, which means that it overrides simulation 2.1. In fact, any of the type 3 simulations is more profitable than simulation 2.1, regardless of the electricity price. That is, simulation 3, in addition to allowing for higher electricity threshold prices, also allows for an effective increase in the profit obtained.

Simulation 3 has proven to be so promising that it is pertinent to perform this simulation for other steam flows produced by the recovery boilers, to see if economically interesting results are also obtained. Simulations were performed for another 4 dates/hours throughout the year, representing a production of 110, 115, 125 and 137.5 ton/h of steam in each recovery boiler.

Table 8 - Profit obtained for each simulation according to the price of electricity (June 4th at 08am).

Date	Electricity Price (€/MWh)	5	10	20	25	30	40	43
4/6 08h	3.1	811	702	485	376	267	50	-14
	3.2	799	690	473	364	255	38	-27
	3.3	828	720	502	393	285	67	2
	2.1	589	481	263	155	46	-171	-236
	2.2	1008	809	413	16	16	-379	-498

This way, it will be possible to understand if simulation 3 is only profitable for steam production close to the minimum referenced in the specification sheet, or for any quantity. The results obtained for these simulations show that similarly to what was verified for June 4th at 08:00, simulation 3 presents a higher profitability margin than simulation 2. However, for all cases with steam production above 105 ton/h, simulation 3.1 presents a higher electricity price limit, being also the most profitable simulation for electricity prices closer to this limit, contrary to what previously happened with simulation 3.3.

5. Solar and Wind Energy

The energy generated by renewable sources may be introduced in the refinery to reduce imports or directly feeding the electric boilers. Whatever the reason, what is certain is that the introduction of renewable energy will allow for more flexibility in the production of electricity in Sines. In this context and considering the current objective of the project, two subsystems will be considered: wind turbines and photovoltaic panels.

5.1 Wind Energy

Wind turbines generate electricity from wind speed, which means that kinetic energy is converted into electrical energy. Due to the high stature of wind turbines, it is necessary to calculate the wind speed at the installation height of the rotor, u_z. According to [12], this can be done by using the power law in equation 5:

$$u_z = u_{zREF} \times (\frac{z}{z_{REF}})^{\frac{1}{n}} \quad \textbf{(5)}$$

Where u_{zREF} is the wind speed (m/s) measured at a reference height. The rotor and reference heights are given by z and z_{REF}, respectively. Finally, n represents the local roughness coefficient.

In the same source, there is an equation to calculate the electric power production of several wind turbines as a function of wind speed and the power curve, which is provided by manufacturers and sellers of the equipment:

$$E_{Eo} = n_{Eo} \times a_1 \times e^{-(\frac{u_z-b_1}{c_1})^2} + a_2 \times e^{-(\frac{u_z-b_2}{c_2})^2} + a_3 \times e^{-(\frac{u_z-b_3}{c_3})^2} \times P_{EoNOM} \quad \textbf{(6)}$$

Where, n_{Eo} refers to the number of wind turbines and P_{EoNOM} to the nominal power of each equipment (in MW).

5.2 Solar Energy

The generation of electrical energy, in photovoltaic technology, is based on the photoelectric effect, where the solar energy present in the photons of the incident radiation is transferred to the electrons of the atomic structure of a given material [13].

In [12], we find an equation that calculates the electricity generation of a photovoltaic panel as a function of the irradiance and temperature of the cells:

$$E_{PV} = n_{PV} \times PMP_{REF} \times \frac{G}{G_{REF}} \times [1 + \gamma_{PV} \times (T_{cel} - T_{REF})] \times \eta_{DA} \quad \textbf{(7)}$$

PMP_{REF}, is the maximum power point of the equipment used (obtained at STC), in W. G_{REF} and T_{REF}, are the irradiance and the temperature of the cells under STC (Standard Test Conditions), in W/m^2 and °C, respectively. G, is the irradiance (W/m^2), γ_{PV} is the coefficient of variation of the maximum power point with the cell temperature (this paper considered - 0.5%/°C) and T_{cel}, the cell temperature, in °C. n_{PV} represents the total number of PV panels and η_{DA} is the efficiency of the conversion equipment.

The cell temperature is, in turn, obtained from equation 8, where T_{amb} is the ambient temperature, in °C, and NOCT corresponds to the nominal operating temperature of the cell, which is provided by the manufacturer (°C):

$$T_{cel} = T_{amb} + \frac{NOCT - 20}{800} \times G \quad \textbf{(8)}$$

5.3 Integration of Renewable Energies in Sines

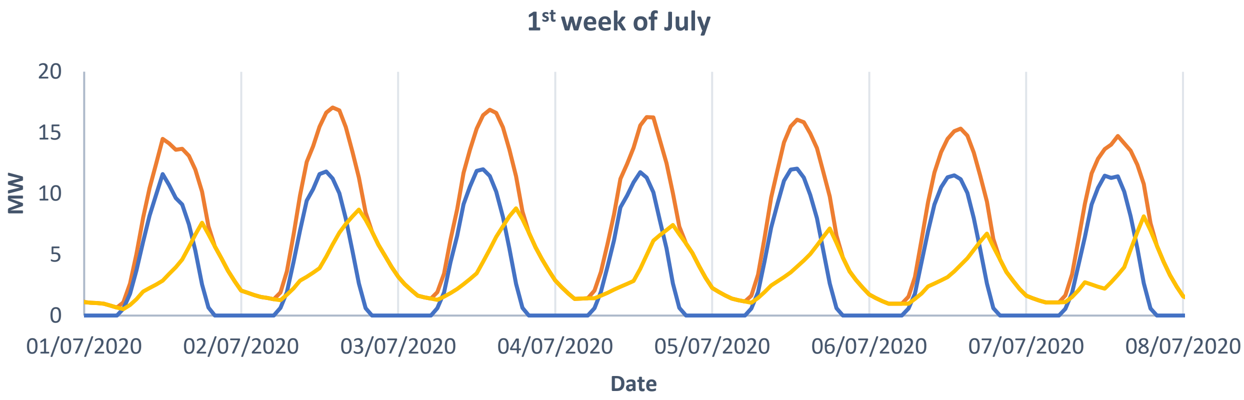
In order to study the atmospheric conditions of the Sines region, and how they impact the production of renewable energy, a model of solar and wind energy generation over a year was made in excel, based on the equations described above. The atmospheric conditions in Sines, mainly: wind speed, total irradiance, and temperature; were obtained based on the PVGIS tool [14]. The characteristics of the solar panels and wind turbines chosen are summarized in Table 9. It is important to note that the total number of equipment units in each subsystem was completely arbitrary, serving only to understand the evolution of electricity production over a year, in the Sines region [15], [16].

Table 9 - Characteristics of solar panels and wind turbines.

Photovoltaic Panel		Wind Turbines	
Variable	Value	Variable	Value
PMP (W)	400	P_{nom} (W)	2000
NOCT (°C)	42	Rotor height (m)	100
Number of units	35000	Number of units	5

In Figure 6, we can observe the generation of renewable energy in the 1st week of July. The orange, blue, and yellow lines represent total, solar and wind production respectively.

The integration of renewable energy in Sines will be associated with the installation of wind turbines and photovoltaic panels. Therefore, it is convenient to estimate the area occupied by the system to assess the feasibility of its integration. Regarding the wind turbines, in order to respect the safety distances, which according to [17], should be 5 to 10 times the rotor diameter, it can be assumed that the wind turbines are arranged in a square-like shape. The vertices correspond to 4 turbines and a fifth equipment is placed in the middle of the square. The arrangement of the photovoltaic modules, was done based on the



configuration of the Alcoutim solar park [18]. This photovoltaic plant occupies 320 hectares with 661.500 solar panels. Applying, a simple rule of 3, we will have an area of about 17 hectares for this subsystem. In terms of investment, [19] lists the typical cost of a wind turbine to be around 1.3M€/MW (in 2021). The investment associated with this subsystem will thus be 13M€. For the calculation of the photovoltaic subsystem, once again the investment value of the Alcoutim solar park was used as reference, which corresponds to 170M€. With that, it is possible to know the initial investment needed to make for the subsystem under study, from the Williams rule. The results are present in Table 10.

Figure 6 - Variation of total energy generation and solar and wind subsystems for the 1st week of July.

Table 10 - Occupied area and estimated capital investment for each subsystem.

Photovoltaic Panel		Wind Turbines	
Variable	**Value**	Variable	**Value**
Area (hectares)	17	Area (hectares)	25
Investment (M€)	29	Investment (M€)	13

6. Conclusions

This paper aimed to identify and suggest flexibility options to be incorporated in the cogeneration system of the Sines refinery. This topic is extremely important due to the increasing prices of electricity, natural gas and carbon taxes. By doing this, we intend to contribute to the development of a new operational model for the unit, leading to decarbonization without economical prejudice.

The first step was to model the cogeneration system in Aspen Plus, which involved setting up a few equipment modules. This model was validated by comparing the results obtained in Aspen with the real data. All equipment, apart from the steam turbines, described a behavior strongly in line with reality, with errors below 5% for the variables considered (streams temperature and pressure and electric energy production).

After validating the model of the cogeneration system, flexibility alternatives were identified, and the possibility of eliminating the afterburner system from the recovery boilers was explored. Two types of simulation were performed to integrate electric boilers to compensate the refinery's steam needs: integration of an 83barg electric boiler; integration of decentralized 3.5 and 24barg electric boilers.

Both options were simulated for various hours throughout the year, to obtain as global a conclusion as possible. Since there was an increase in electricity needs, it was necessary to study the economic viability of the case studies and obtain the limit electricity prices for which profit is possible. We also evaluated the effective profit of each simulation, using different electricity prices. The decentralized configuration always generated better results than the centralized boiler option, even though the electricity price caps are below 35€/MWh. It is thus possible to conclude that the incorporation of electric boilers with a lower pressure range is more profitable than the option of integrating an electric boiler to produce high-pressure steam (even without turbogenerators).

We then went to identify options for studying the flexibility of the cogeneration unit by regulating the supply of natural gas to the gas turbines and the recovery boilers. The focus was on directing the cogeneration unit to produce steam at various pressure levels, without giving importance to the production of electricity. The results shown that it was possible to obtain higher electricity limit prices, around 40€/MWh.

It was concluded that the best operational model requires a combination of decentralized boilers and the GT operating below capacity.

Finally, we addressed the integration of renewable energies (solar and wind) at the Sines refinery, with the aim of minimizing electricity imports. We developed a model in Excel that allows the hourly production of both subsystems to be obtained as a function of atmospheric conditions. We considered 5 wind turbines with a unit power of 2MW and 35000 photovoltaic modules of 400W. It was possible to obtain a maximum production of 19.16MWh, which would result in a considerable decrease in the refinery's imports, particularly during the summer months.

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