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Optimal Planning for the Cogeneration Energy System using Energy Hub Model

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Cogeneration or combined heat and power (CHP) energy system could concurrently produce electrical and heat energies. Nonetheless, its integration in energy planning would need to consider interactions with other energy carriers, energy storages, and transmission networks. Previous works have used energy hub (EH) modelling to optimise the energy flow in a CHP energy system with predetermined energy components. In this paper, an Optimal Cogeneration Model (OCM) is proposed to consider the EH design which (1) enables the flexible selection between different energy transformation technologies, then (2) minimises the cost and environmental emission constraints concerning the technical characteristics and operating conditions of the selected EH components. Mixed-integer linear programming (MILP) has been used to model the optimisation problem in GAMS software. Based on the case study, an EH with CHP and energy storage system (ESS) has been developed with the minimised total annual cost (TAC) of 27.02 x 10^6 MYR/y for a pharmaceutical facility. The research output - the developed OCM serves as an integrated analysis tool for potential cogenerators to plan and determine the economic feasibility of CHP implementation.

1. Introduction

The rising global population has driven the need for researchers to address the energy trilemma in energy system planning and design to consider aspects of environmental protection, energy economics, and security (World Energy Council, 2020). The sudden outbreak of COVID-19 in late December 2019 has shocked the world, affected the progress of energy transition towards sustainability (Klemeš et al., 2021) and caused significant economic damages on the global economy (Buheji et al., 2020). Under these circumstances, energy planning post-COVID-19 should consider an appropriate level of investment cost as the global economy is still recovering. One such suitable candidate is cogeneration or combined heat and power (CHP) energy system. By generating electricity and heat simultaneously, CHP has a higher overall efficiency of 80-90 %, as compared to the conventional stand-alone generation which have a typical efficiency of 35-55 % (Bilgen et al., 2015). CHP could eliminate an additional 10-15 % energy losses associated with the grid transmission (Bhatia, 2014). CHP utilises less fuel – minimises greenhouse gases (GHG) emissions and overall energy production costs. An optimal design of CHP energy system would synergise the electricity and gas systems, and it is known as a multi-energy system (MES). The components such as energy transformation devices, energy storage systems (ESS), and utility networks interact with one another in an integrated MES with respect to the intended constraints. To model the MES, the concept of energy hub (EH) was introduced. An EH constrains the energy flow by correlating the input and output ports via a coupling factor (Mohammadi, 2017), as shown in Eq(1). L_β and P_α represent the output of energy carrier β and input of energy carrier α, respectively. The flow of the energy transformation is decided by the $cf_{\alpha\beta}$, which defines the coupling factor or conversion efficiency.

$$L_\beta = cf_{\alpha\beta} \times P_\alpha \quad (1)$$

From the literature review, the concept of EH has been utilised to design an optimal CHP energy system. EH transforms the input energies (from electricity and gas infrastructures) to fulfill the energy demands at its output ports. To handle the EH with different energy transformation technologies (as in a CHP-integrated energy

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system), a coupling matrix would be generated using Eq(1) as the basis. Wang et al. (2017) presented a multi-objective EH for CHP implementation which optimises the energy and carbon emission costs. Lu et al. (2020) proposed an optimal load dispatch model for a community EH with CHP as well by utilising a robust optimisation approach. Another paper by Garmabdari et al. (2020) described a multi-objective optimisation of CHP operation using the EH model by considering utility fluctuations and ESS operational dynamics.
Previous works have predetermined the components to be included in the EH – the optimisation model could not decide the type and number of EH units. There is a relative lack of research to allow the flexibility of the optimisation model to select the energy components in the optimal synthesis of an EH model for CHP installation. To bridge the identified gaps, an Optimal Cogeneration Model (OCM) is proposed to demonstrate an integrated decision of energy components installation for CHP operation using the EH model with consideration of budget and environmental constraints. A mixed-integer linear programming (MILP) model would be postulated to optimise the configuration of the proposed EH. The developed OCM could serve as an effective decision tool for potential owners to gauge the economic and environmental potential of CHP implementation.

2. Methodology

This section presents the development of OCM to target the cost incurred and carbon emission in an EH. The hub consumes grid electricity and natural gas to satisfy the electrical and thermal energy loads. Decision on the availability of transformer(s), CHP(s), and auxiliary boiler(s) as conversion technologies is modelled in OCM.

2.1 Problem Statement

Given are the electrical load, De_t and heating load, Dh_t to be fulfilled by energy sources from the electrical grid, Eg_t and gas infrastructure, NG_t in an EH. The hub could select from a few transformer(s), CHP(s), and auxiliary boiler(s) with different economic (investment cost and operating & maintenance (O&M) cost) as well as technical data (efficiency and maximum capacity) to provide the power outputs ($Ep1_t$, $Ep2_t$, $Hp1_t$, and $Hp2_t$). Battery and thermal ESS provide additional flexibility to the operation of EH by allowing energies to be stored (Ech_{t-1} and Hch_{t-1}) and discharged ($Edch_t$ and $Hdch_t$). The problem for EH design consists of optimising: (A) the multi-period operating schedule and (B) selection of EH components with objective functions of minimised total annual cost (TAC) and reduced carbon emission. The superstructure of the problem is defined as follows (see Figure 1).

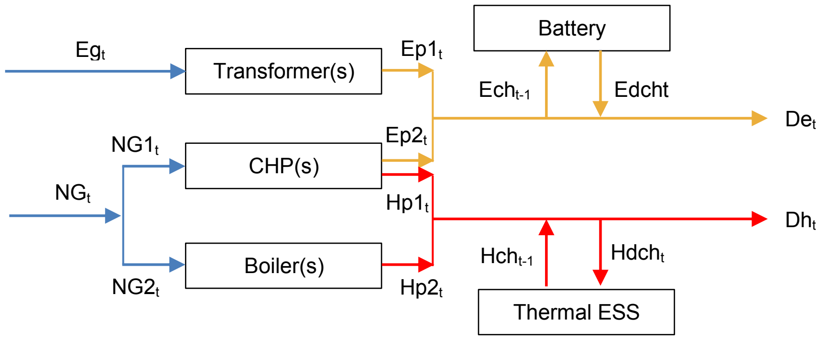


Figure 1: Superstructure of OCM showing the optimal EH design with CHP implementation to consider the integration of transformer(s), CHP(s), auxiliary boiler(s), electrical ESS, and thermal ESS.

2.2 Model Development

The main objective of the developed OCM is to determine the optimal multi-period operation of EH components at each time interval, t so that the energy loads can be satisfied with a minimum TAC as described in Eq(2). To integrate the environmental constraint in the optimisation model, carbon emission is introduced as a cost penalty to the TAC, namely, total carbon emission cost (TCC). The formulation of the TAC in OCM is given in Eq(3). Capital recovery factor (CRF) is utilised to annualise the total investment cost (TIC) based on the project expected lifespan, while annual operating day (AOD) is included to scale up the daily total O&M cost (TOM), total utility cost (TUC), and TCC. The economic parameters in TAC can be found in Eqs(4)-(7). The set of conversion technologies and ESS is denoted as p and es, while the hourly time interval in a day is given as t. In TIC and TOM, $IC_{p/es}$ and OMC_p represent the investment and O&M costs for p or es. n_p describes the integer variable for selecting the number of p installations, while $Pgen^{e/h}_{p,t}$ depicts the electrical or thermal outputs of p at a given t. In TUC, grid connection costs (Grid tariff, MD charge, MD, Stdby rate, and Stdby cap) are the electricity grid tariff, maximum demand charge, maximum demand, standby rate, and standby capacity. The hourly natural gas procurement cost is given as NG rate. Grid CPF and NG CPF in TCC account for the carbon emission price factor for the electrical grid and gas infrastructure.

$$\min TAC \quad (2)$$

$$TAC = CRF \times TIC + AOD \times (TOM + TUC + TCC) \quad (3)$$

$$TIC = \sum_{p} IC_p \times n_p + \sum_{es} IC_{es} \quad (4)$$

$$TOM = \sum_{t}\sum_{p} OMC_p \times Pgen^{e/h}_{p,t} \quad (5)$$

$$TUC = \left(\sum_{t} \text{Grid tariff} \times Eg_t + \text{MD charge} \times MD + \text{Stdby rate} \times \text{Stdby cap}\right) + \left(\sum_{t} \text{NG price} \times NG_t\right) \quad (6)$$

$$TCC = \sum_{t} \text{Grid CPF} \times Eg_t + \sum_{t} \text{NG CPF} \times NG_t \quad (7)$$

The energy carriers of grid electricity, Eg_t and natural gas, NG_t connect different energy transformation devices – transformer(s), CHP(s), and auxiliary boiler(s) to produce outputs – $Ep1_t$, $Ep2_t$, $Hp1_t$, and $Hp2_t$ with charging (Ech_{t-1} and Hch_{t-1}) as well as discharging ($Edch_t$ and $Hdch_t$) abilities for ESS to supply the electrical and thermal loads (De_t and Dh_t). Eq(8) and (9) express the energy balance of the proposed EH. The outputs of different p for the transformer(s), CHP(s), and auxiliary boiler(s) are given as $Pgen^{e/h}{}_{p,t}$ and presented in Eq(10).

$$De_t + Ech_t = Ep1_t + Ep2_t + Edch_t \quad \forall t \quad (8)$$

$$Dh_t + Hch_t = Hp1_t + Hp2_t + Hdch_t \quad \forall t \quad (9)$$

$$\sum_{p} Pgen^{e/h}_{p,t} = Ep1_t \text{ or } Ep2_t \text{ or } Hp1_t \text{ or } Hp2_t \quad \forall t \quad (10)$$

For the selection of energy transformation devices p, the output $Pgen^{e/h}{}_{p,t}$ is obtained by multiplying the input (Eg_t, $NG1_t$, or $NG2_t$) with the conversion efficiency, eff_p. An integer variable, n_p is introduced to correlate the decision with upper, $Cap^{max}{}_p$, and lower capacity limits, $Cap^{min}{}_p$ of individual p components. To match the dimension of the equations, the input entering the different p components at given t is given as $Eg_{p,t}$, $NG1_{p,t}$, or $NG2_{p,t}$. The generalised equations to indicate the decision are shown in Eq(11) and Eq(12). Eq(13) and Eq(14) show the remaining constraints to ensure the model validity, where Eg_t and NG_t are kept in energy balance.

$$Pgen^{e/h}_{p,t} = eff_p \times Eg_{p,t} \text{ or } NG1_{p,t} \text{ or } NG2_{p,t} \quad \forall t\ \forall p \quad (11)$$

$$n_p \times Cap^{min}_p \leq Pgen^{e/h}_{p,t} \leq n_p \times Cap^{max}_p \quad \forall t\ \forall p \quad (12)$$

$$\sum_{p} Eg_{t,p} \text{ or } \sum_{p} NG1_{t,p} \text{ or } \sum_{p} NG2_{t,p} = Eg_t \text{ or } NG1_t \text{ or } NG2_t \quad \forall t \quad (13)$$

$$NG_t = NG1_t + NG2_t \quad \forall t \quad (14)$$

The mathematical models of ESS are formulated to depict their ability to charge and discharge energies in Eqs(15)-(19). $SOC^{e/h}{}_{es,t}$ represents the stored energy in the electrical (battery) and thermal ESS at time interval, t. $Ech^{e/h}{}_{es,t}$, $Hch^{e/h}{}_{es,t}$, $Edch^{e/h}{}_{es,t}$, and $Hdch^{e/h}{}_{es,t}$ describe the dispatch of electricity and heat, with charging ($ceff^{e/h}{}_{es}$) and discharging ($dceff^{e/h}{}_{es}$) efficiencies associated with es units. As for the decision of charging or discharging mode, binary variables of $IEch_t$, $IHch_t$, $IEdch_t$, and $IHdch_t$ are introduced. $Ech^{min}{}_{es}$, $Hch^{min}{}_{es}$, $Ech^{max}{}_{es}$, $Hch^{max}{}_{es}$, $Edch^{min}{}_{es}$, $Hdch^{min}{}_{es}$, $Edch^{max}{}_{es}$, and $Hdch^{max}{}_{es}$ represent the lower and upper dispatch capacities of different ESS, while $SOC^{min}{}_{es}$ and $SOC^{max}{}_{es}$ describe the maximum and minimum state-of-charge for ESS.

$$SOC^{e/h}_{es,t+1} = SOC^{e/h}_{es,t} + \frac{Ech^{e/h}_{es,t} \text{ or } Hch^{e/h}_{es,t}}{ceff^{e/h}_{es}} - \frac{Edch^{e/h}_{es,t} \text{ or } Hdch^{e/h}_{es,t}}{dceff^{e/h}_{es}} \quad \forall t\ \forall es \quad (18)$$

$$\mathrm{Ech}_{es}^{min} \text{ or } \mathrm{Hch}_{es}^{min} \leq \mathrm{Ech}_{es,t}^{e/h} \text{ or } \mathrm{Hch}_{es,t}^{e/h} \leq \mathrm{Ech}_{es}^{max} \text{ or } \mathrm{Hch}_{es}^{max} \quad \forall t\ \forall es \tag{19}$$

$$\mathrm{Edch}_{es}^{min} \text{ or } \mathrm{Hdch}_{es}^{min} \leq \mathrm{Edch}_{es,t}^{e/h} \text{ or } \mathrm{Hdch}_{es,t}^{e/h} \leq \mathrm{Edch}_{es}^{max} \text{ or } \mathrm{Hdch}_{es}^{max} \quad \forall t\ \forall es \tag{20}$$

$$\mathrm{SOC}_{es}^{min} \leq \mathrm{SOC}_{es,t}^{e/h} \leq \mathrm{SOC}_{es}^{max} \quad \forall t\ \forall es \tag{21}$$

$$\mathrm{IEch}_t + \mathrm{IEdch}_t \text{ or } \mathrm{IHch}_t + \mathrm{IHdch}_t \leq 1 \quad \forall t \tag{22}$$

3. Case Study

A hypothetical energy demand of a typical pharmaceutical facility located in Malaysia is adapted from the dataset provided by Angizeh et al. (2020). In this case study, it is assumed that the owner of the premise would like to evaluate the feasibility of integrating CHP(s) of gas turbine with waste heat recovery unit into its energy production system with regards to the budget and environmental constraints. The superstructure of the proposed EH is shown in Figure 1 above. Given the electrical load data, the thermal load profile can be postulated by considering the heat-to-power ratio of 1 for the pharmaceutical industry (Gambini and Vellini, 2019). As the electrical load shape is relatively constant, the NORMINV formula in Excel is used to generate random values within the standard deviation to account for fluctuations of the heating load. Figure 2 shows the electrical and thermal demand requirements to be supplied by the proposed EH. The electricity would be purchased from Tenaga Nasional Berhad (TNB) under the E2 tariff category (Tenaga Nasional Berhad, 2014), with a maximum demand charge of 37.00 MYR/kW, on-peak price of 0.355 MYR/kWh, off-peak price of 0.219 MYR/kWh, and standby rate of 14.00 MYR/kW. As for natural gas, Gas Malaysia Energy & Services Sdn. Bhd. would supply the fuel required at an average price of 0.092 MYR/kWh (Malaysia Energy Commission, 2021).

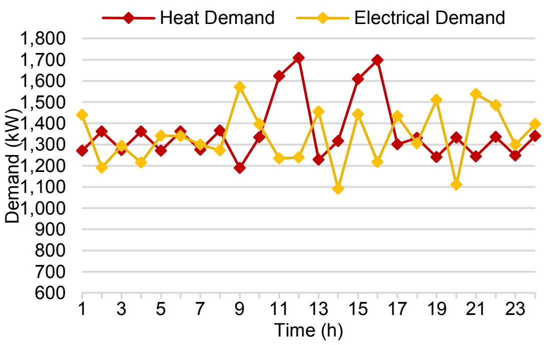


Figure 2: Energy demand loads of a pharmaceutical facility (adapted from Angizeh et al., 2020).

3.1 Parameters of energy hub

Industrial processes operate 8760 h/y, and their AOD is 365 d. The optimal EH design considers an economic lifetime of 10 y with a 6 % discount rate (CRF = 0.136). Grid CPF and NG CPF are priced at 0.097 and 0.023 MYR/kWh, given the emission coefficient of 0.972 and 0.230 kg CO_2eq/kWh for grid purchased electricity and natural gas (Saberi et al., 2019), assuming a social carbon cost (SCC) of 100 MYR/ton CO_2eq by averaging the values suggested by different climate economic models in Malaysia (Rao and Mustapa, 2021). The integration of ESS is considered too – the electrical and thermal energies could be stored and dispatched depending on the utility price. The economic and technical parameters for the operating units are presented in Table 1.

3.2 Results and Discussion

The optimisation for the operating scheme is conducted for the following scenarios: (A) considering integration of transformer(s) and auxiliary boiler(s), (B) integration of scenario A and CHP(s), and (C) integration of scenario B and ESS, as shown in Table 2. It is found that EH design with CHP(s) and ESS as in case scenario (C), has the lowest TAC of 27,015,679.20 MYR/y – which includes CHP(s) to produce electricity and heat outputs, as well as ESS to provide flexibility for the dispatch of the energies. The other cost components in case scenario (C) are as follows: TIC of 214,200 MYR/y (after accounting of CRF), TOM of 22,300,530.29 MYR/y, TUC of 3,507,473.44 MYR/y, and TCC of 993,475.47 MYR/y. TOM contributes most significantly to TAC calculation. It is found that the inclusion of CHP(s) in EH could effectively reduce GHG emissions as the TCC of 94.10 x 10^4 and 99.34 x 10^4 MYR/y for cases (B) and (C) is significantly lower than TCC of 15.76 x 10^5 MYR/y for case (A).

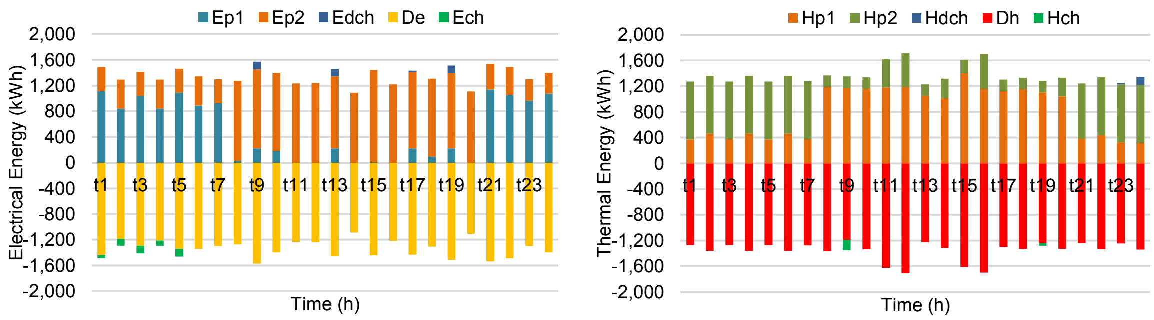
At a SCC of 100 MYR/ton CO_2eq, around 6,350- and 5,826-ton CO_2eq can be reduced per year if CHP(s) are introduced as shown in cases (B) and (C).
Figures 3a and 3b illustrate the output of transformer(s) as Ep1, CHP(s) as Ep2 and Hp1, and auxiliary boiler(s) as Hp2 for the optimisation of case scenario (C). Ech, Edch, Hch, and Hdch represent the charging as well as discharging operations of battery and thermal ESS to complement the optimal EH configuration of OCM. The utilisation of CHP(s) is high when the grid electricity is priced at on-peak tariff during t8 to t20 as shown by Ep2 and Hp1. Electricity is stored (Ech) during off-peak tariff and discharged when tariff is high as in Figure 3a. Meanwhile, excess heat energy is stored (Hch) when the CHP(s) are utilised as in Figure 3b.

Table 1: Economic and technical parameters of candidate technologies and ESS available for the EH.

	Maximum number of units	Capacity (kW)		Efficiency (%)			Cost	
		Min	Max	Electrical	Thermal	Charging/ Discharging	Investment (MYR)	O&M (MYR/kWh)
Transformer I (Tr. I)	3	0	250	95	-	-	48,000	0.80
Transformer II (Tr. II)	3	0	300	95	-	-	55,000	0.80
Transformer III (Tr. III)	3	0	280	97	-	-	60,000	0.80
CHP I	2	90	450	40	45	-	280,000	1.00
CHP II	2	120	600	45	40	-	350,000	1.00
CHP III	2	100	500	40	40	-	275,000	1.00
Boiler I (B. I)	3	80	400	-	68	-	60,000	0.90
Boiler II (B. II)	3	70	350	-	70	-	70,000	0.90
Boiler III (B. III)	3	90	450	-	70	-	75,000	0.90
Battery (Bat.)	-	120	600	-	-	90	180,000	-
Thermal ESS (TES)	-	160	800	-	-	85	100,000	-

Table 2: Comparison of OCM for the design of EH in case scenarios (A), (B), and (C).

Case Scenarios	Optimal Configuration											Total Annual Cost (TAC) (MYR/y)
	Transformer			Boiler			CHP			ESS		
	I	II	III	I	II	III	I	II	III	Bat.	TES	
A	3	0	3	1	0	3	-	-	-	-	-	27,597,188.79
B	0	1	3	0	0	2	2	1	0	-	-	27,065,674.53
C	0	1	3	0	0	2	2	1	0	✓	✓	27,015,679.20



(a) (b)

Figure 3: The hourly energy production schedule to satisfy (a) the electrical and (b) thermal loads using OCM.

The developed OCM considers the variability in TIC and TOM of different EH components and subsequently, decide their integration in energy system. To effectively gauge the contribution of TUC and TCC in TAC calculation, sensitivity analysis for (1) 25 % increase of electricity tariff, (2) 25 % increase of natural gas price, and (3) 25 % increase of carbon emission price factors is considered as in Table 3. The sensitivity analysis is carried out by allowing the OCM to integrate transformer(s), auxiliary boiler(s), CHP(s), and ESS(s) – similar to case scenario (C) in Table 2. It is observed that TAC increases by a little (<5 %), despite 25% increment in electricity tariff, fuel price, and carbon emission price factors. However, the output of CHP(s) would increase when the electricity tariff is high, as in sensitivity case (1), to replace grid purchase.

Table 3: Sensitivity analysis for case scenarios (1), (2), and (3).

Sensitivity Analysis	Optimal Configuration											Total Annual Cost (TAC) (MYR/y)
	Transformer			Boiler			CHP			ESS		
	I	II	III	I	II	III	I	II	III	Bat.	TES	
Baseline	0	1	3	0	0	2	2	1	0	✓	✓	27,015,679.20
1 (electricity tariff increase)	0	0	2	0	1	0	2	1	0	✓	✓	27,214,471.16
2 (natural gas price increase)	0	1	3	0	3	0	2	1	0	✓	✓	27,558,752.37
3 (SCC increase)	0	1	3	0	0	2	2	1	0	✓	✓	27,263,943.53

4. Conclusion

An OCM for EH design with CHP integration is developed in this paper as a MILP model. The carbon emissions of EH are transformed into a penalty cost function for the TAC via emissions coefficient, and the objective function for the OCM is based on TAC minimisation. The optimal EH design has a TAC of 27.02 x 10^6 MYR/y and selects CHP(s) and ESS. The proposed model systematically gauges the CHP implementation and suggest the optimal type and number of EH unit installations for industrial facility. The developed OCM could demonstrate the feasibility of the EH and promote the adoption of CHP(s). Future research could attempt to include social constraints and investigate the trade-offs between economic, environmental, and social parameters. Grid connection, EH components, and ESS could be modelled with more constraints to represent a realistic representation of EH operation. The reliability of the optimal EH design can be investigated as well.

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