

Life cycle based optimal design of utility system in offshore plants

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Abstract—Offshore plants have many inherent constraints and risks compared to onshore plants, and it is crucial to optimize the operation of the offshore plant by adhering to constraints. Previous studies proposed a framework of utility systems that operate under various conditions. However, few studies have addressed the optimization of utility systems during the operating life cycle. To fill in this gap, we propose a new methodology for the design and optimization of the utility systems in the offshore plants. The utility systems are designed and optimized in Aspen Utilities Planner, considering the full life cycle of the oil and gas wells. For this, we first developed steady-state models of the topside processes based on every feasible operating scenario throughout the full life cycle. Then the utility consumption data was extracted from the simulation results and analyzed. The power system was designed using Aspen Utilities Planner (AUP), and it was optimized to maximize the thermal efficiency of the utility system, satisfying power demand for all the scenarios. The optimized results illustrate the significant saving of the operating cost and reduction of CO₂ emission rate. Our studies suggest a generic framework to design utility systems in offshore plants.

Keywords: Modeling, Offshore Plant, Optimization, Topside Process, Utility System

INTRODUCTION

As industrial development accelerates, the problem of greenhouse gas (GHG) emissions arises gradually. Fig. 1 shows the global CO₂ emission share and trends in CO₂ emission growth [1]. By the mid-2000s, developing countries (e.g., China and India) showed significant industrial growth rates, and CO₂ emissions rapidly increased accordingly.

There are many sources for GHG emissions in the world, and fuel combustion is one of them. Specifically, in fuel combustion, CO₂ emissions steadily increased until 2018 as shown in Fig. 2(a). Also, Fig. 2(b) shows global CO₂ emissions from fuel combustion by industrial field [2]. As shown in Fig. 2(b), the industry field generates 14.32 Gt CO₂, which is 43% of its total emissions in 2017 [2]. Based on this, it is necessary to reduce the CO₂ emissions generated from the industry field. To this end, a broad range of studies to reduce the CO₂ emission have been actively conducted [3-6]. On the other hand, there has been little research on the reduction of CO₂ emission in the offshore plant.

An offshore plant is a large structure with facilities (e.g., well drilling, a mooring system, living quarters, the process of oil, natural gas (NG), utility system, and storage tank of the products), which has a series of unit processes that treat impurities and separate feeds to make desired products of oil and gas from deep-sea [7].

Among these facilities, the utility system (e.g., power generation system, cooling system, and heating system), which assists the top-

side process in making the product, is one of the most important systems of the offshore plant. The utility cost accounts for most of the process of operating cost. Furthermore, the power generation system, which is one of the utility systems, emits the most CO₂ in the offshore plant. Therefore, the effective modeling and operation of the utility system are crucial and required to save the operating cost and reduce CO₂ emission in the offshore plant.

Previously, there have been attempts to optimize the utility systems in order to save operating costs and reduce CO₂ emission [8]. However, most of the computational models were developed by considering only a few specific operating conditions. A recent study showed the design and optimization of the utility system, but it did not consider an actual operating period [9]. Another study showed the concepts for power and heat supply to offshore plants, simulating the utility system during the actual operating periods [10-12]. However, this model was restricted to stable operating conditions, making it inadequate to explain the utility system in highly fluctuating conditions. Williams and Smulders developed a conceptual topside process design for an offshore plant using Aspen HYSYS [13].

Recognizing these limitations, we present a new methodology in this work to design an optimized utility system of the offshore plants that operates flexibly with high thermal efficiency and minimum CO₂ release to atmosphere. The rest of the paper is organized as follows. The next section provides elaborated details about the description of thermal efficiency and process equipment. It is followed by explaining the details about the methodology of utility system design. Subsequently, the simulation and optimization results under various operating conditions are presented. Lastly, the conclusion is given.

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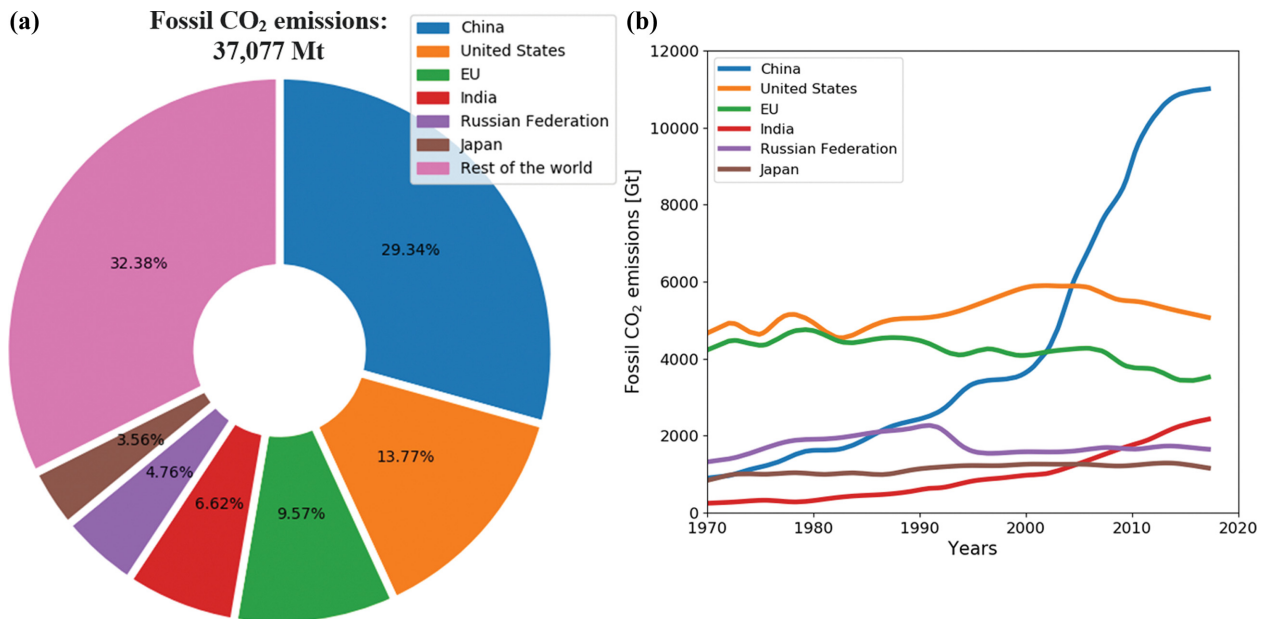


Fig. 1. (a) Share of CO₂ emission for each country in 2017, and (b) trend of CO₂ emission for each country by 2017 [1].

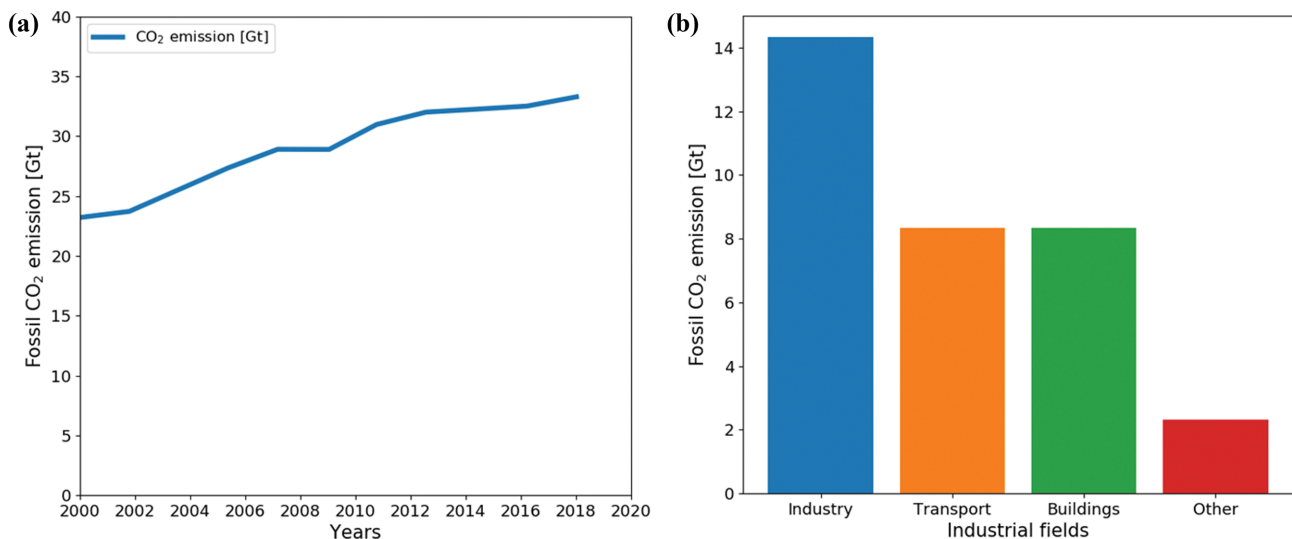


Fig. 2. (a) Global trend of the CO₂ emissions from fuel combustion by 2018 and (b) global CO₂ emissions from fuel combustion by industrial field in 2017 [2].

INTRODUCTION OF THE UTILITY SYSTEM IN OFFSHORE PLANT

1. Thermal Efficiency of Combined Cycle Power Plant (CCPP)

CCPP is a power generation system that combines different types of heat engines. Generally, the CCPP is composed of a gas turbine generator and a steam turbine generator. Heat engines convert heat and chemical energy into mechanical energy, which can be used to generate power. Their efficiency depends on the temperature of the heat source, which is defined as [14]:

$$\eta_{\text{cycle}} = \frac{W_{\text{cycle}}}{Q_H} = \frac{Q_H - Q_C}{Q_H} = 1 - \frac{Q_C}{Q_H} = 1 - \frac{T_C}{T_H} \quad (1)$$

where η_{cycle} is the efficiency of the cycle, W_{cycle} is the work of the cycle, Q_H is the heat of the hot source, Q_C is the heat of the cold source, T_H is the temperature of the input source, and T_C is the temperature of the output source.

The efficiency of the CCPP is similar to that of the single heat engine, which is presented as follows:

$$\eta_{\text{cycle}} = \frac{W_{\text{cycle}}}{Q_H} = \frac{\dot{W}_{GT} + \dot{W}_{ST}}{\dot{m}_f \text{LHV}} = \frac{\dot{W}_{\text{turbine}} - \dot{W}_{\text{compressor}} + \dot{W}_{ST}}{\dot{m}_f \text{LHV}} \quad (2)$$

where \dot{W}_{GT} is the work of the gas turbine per time, \dot{W}_{ST} is the work of the steam turbine per time, \dot{m}_f is the mass flow of the fuel, LHV is the lower heating value, \dot{W}_{turbine} is the work of the turbine per time, and $\dot{W}_{\text{compressor}}$ is the work of the compressor per time.

The fuel consumption rate in the power generator is calculated as follows:

$$\text{Fuel consumption rate} = \frac{1}{\eta_{\text{cycle}} \cdot \text{LHV}} = \frac{Q_H}{W_{\text{cycle}} \cdot \text{LHV}} = \frac{\dot{m}_f}{\dot{W}_{\text{cycle}}} \quad (3)$$

The CO₂ emission rate is defined as:

$$\text{CO}_2 \text{ emission rate} = \frac{\alpha \cdot \dot{m}_f}{\dot{W}_{\text{cycle}}} \quad (4)$$

where α is the fuel mass conversion factor, which is 2.75 kg_{CO₂}/kg_{fuel}.

In this study, these equations are used to calculate the results of the utility system.

2. General Utility System in Offshore Plants

The utility system is required to supply power, steam, cooling water, etc. to operate the topside process in offshore plant, and it generally contains the cooling system, heating system, and power generation system. A cooling utility system is generally used when heat needs to be eliminated at temperature below approximately 120 °C. Cooling water is the widely used cold utility in the temperature range of 120 °C to 40 °C. If a process stream is cooled to less

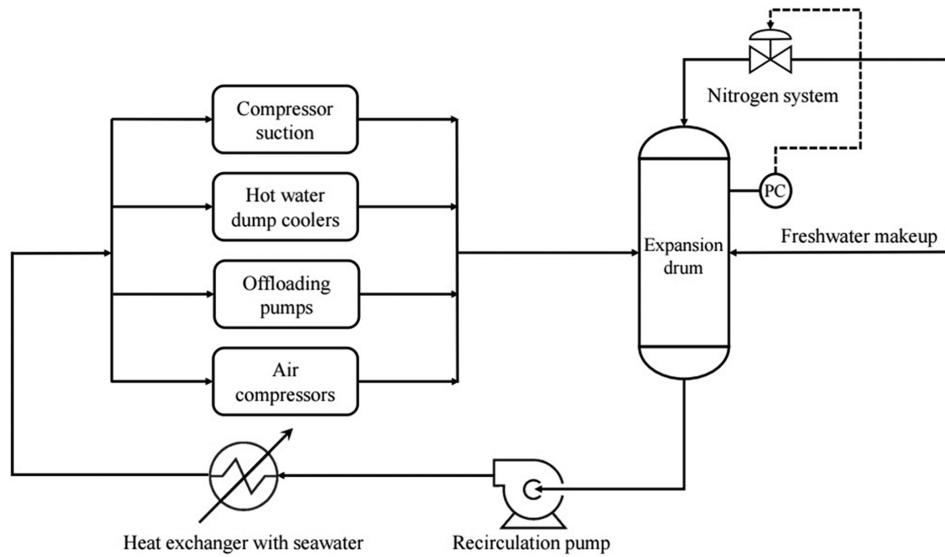


Fig. 3. Schematic illustration of the cooling utility system in offshore plants.

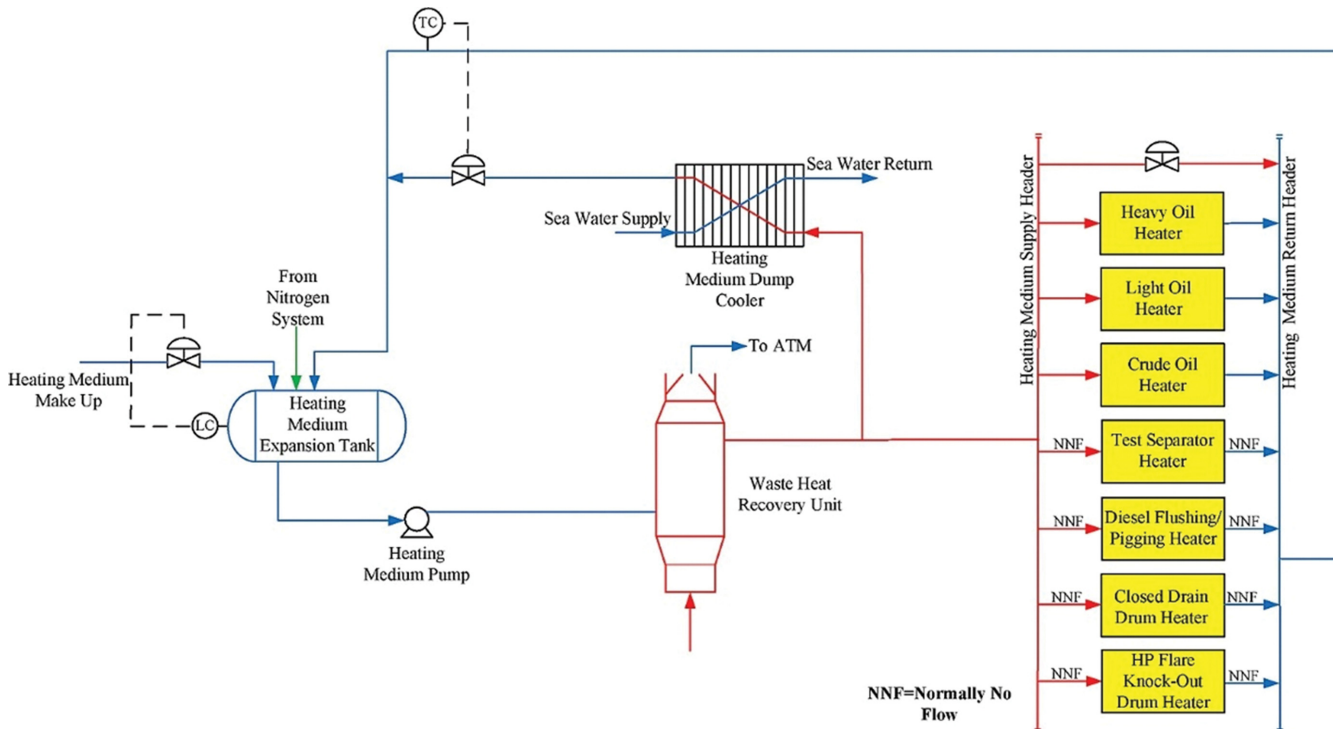


Fig. 4. Schematic illustration of the heating utility system in offshore plants [16].

than 40 °C, chilled water or refrigeration would be needed [15]. Fig. 3 represents a typical cooling utility system in the offshore plant. The cooling utility system consists of several different units: cooling expansion drum, cooling water recirculation pumps, and cooling water service pumps. The freshwater from the process enters the expansion drum and flows through recirculation pumps to exchange heat with seawater. Then, cooled fresh water is delivered to process, where it is needed [16]. Generally, cooling systems should be as small as possible because of seawater. This is because Titanium is used as a material in cooling systems to prevent corrosion caused by seawater, which is too expensive.

The heating utility system provides the heat supply to streams that need to be heated. The heating utility system has a closed-loop circuit, where the waste heat recovery unit (WHRU) is utilized. The heating utility system consists of a heating medium expansion tank, heating medium pump cooler, heating medium pump, and WHRU. At the WHRU, the circulated heating medium is heated using exhaust gas from the gas turbine and sent to the supply header line, where it is fed to the HEN [17]. Then the streams are heated by the heating medium in the HEN. Fig. 4 illustrates the configuration of the heating utility system in an offshore plant.

The power supply system produces and distributes power to the necessary processes. There are three criteria for designing an electrical system. Firstly, the feasibility should be considered. The power should be continuously available whenever the equipment operates. Also, the power supply should always be within the range that the equipment can tolerate without damage and loss of performance. Secondly, the power cost should not be expensive, which also considers the logistical and environmental conditions, where generation and distribution take place. Thirdly, it should not have unnecessary margin in terms of utility supply. Excessive demand (e.g., excessive fuel, cooling medium, and heating medium) should not be considered in the offshore plant. This is because the extra storage system cannot be placed due to restriction of layout. Lastly, the safety requirements pertaining to an offshore installation should comply with particularly those associated with fire and explosion hazards [18].

For these criteria, steam and gas turbines are widely used as a unit to generate power on an offshore platform. The steam turbines are suitable for medium and low temperature (LT) ranges. Specifically, steam turbines are often used as the bottoming cycle, which is a secondary power generator in the combined cycle rather than a single steam cycle. This is because the gas turbines release high temperature (HT) exhaust gas, which can be utilized for making steam, and the steam turbines can generate extra power so that the thermal efficiency increases [19]. The two major steam turbines used in the offshore process are extraction condensing turbine and back-pressure turbine.

The extraction condensing turbines are the most widely used

steam turbines. These turbines can extract the most energy from incoming steam and generate extra power. Moreover, they can be operated flexibly regardless of the variation of power demand, which is appropriate for places where power demand varies greatly. On the other hand, back-pressure turbines are used to supply steam into the process. Power is also generated but the main purpose of back-pressure turbines is steam supply. The feature of back-pressure turbines is that the pressure of the steam is adjusted to the desired pressure. They extract a little energy from the steam, send depressurized steam to the required units [20].

Gas turbines are good power generators in the offshore plant due to the availability of hydrocarbon gas as a fuel and the high power-to-weight ratio to minimize the footprint area. They consist of a compressor, combustion chamber, and turbine. The compressor takes air from the surrounding and compresses it to a pressure in the range of 10 to 35 bar, depending on the type of gas turbine. The pressurized air is then mixed with the fuel in the combustion chamber in the form of a direct-fired heater. Then, HT gas operates the turbine to generate power [21,22]. Once the power is generated, exhaust gas is expanded to slightly more than the atmospheric pressure in a turbine, whose temperature ranges from 450 to 650 °C, and it leaves the gas turbine.

Gas turbines can be classified as aero-derivative and industrial types. The aero-derivative type is a unit with an excellent power-to-weight ratio because a gas generator is lighter than the integral unit on an equivalent industrial machine. The typical characteristics of aero-derivative gas turbine are the high power-to-weight ratio, compact by volume, and high-pressure ratio. Moreover, procurement and maintenance costs are less important than those of industrial gas turbines, where long intervals between overhauls are demanded. For these reasons, aero-derivative gas turbines have more advantages in terms of materials, efficiency, and maintainability [23]. Whereas, industrial gas turbines are purpose-built engines to generate power. These machines tend to be less fuel-efficient than the equivalent aero-derivative type, while they have a good reputation for reliability and the toleration of fuel supply or load abnormalities.

Due to the complex structure of a gas turbine, a small number of machines with high power generation should be designed. They are constrained to an optimal number of machines (i.e., approximately three machines) to meet the needs for the continuity of supply, maintenance, and reliability [23].

In this study, the specifications of power generators used in the offshore plants are applied to the gas turbines. The specifications for the turbines are shown in Table 1. LM 2500+G4, LM 6000 PF+, and LM 6000PC are used in the utility system, which are aero-derivative type and have high net efficiency.

The CCPP combines a gas turbine and a steam turbine power plant, where the remaining heat in the exhaust from the gas tur-

Table 1. Specifications of gas turbine used in this study

	Type	Net output	Net efficiency	Pressure ratio	Exhaust Temp.	Fuel
LM 2500+G4	Aero-derivative	35 MW	38.3%	24.2 : 1	549 °C	NG
LM 6000 PF+	Aero-derivative	52 MW	41.3%	33.1 : 1	500 °C	NG
LM 6000 PC	Aero-derivative	42 MW	41+%	29 : 1	451 °C	NG

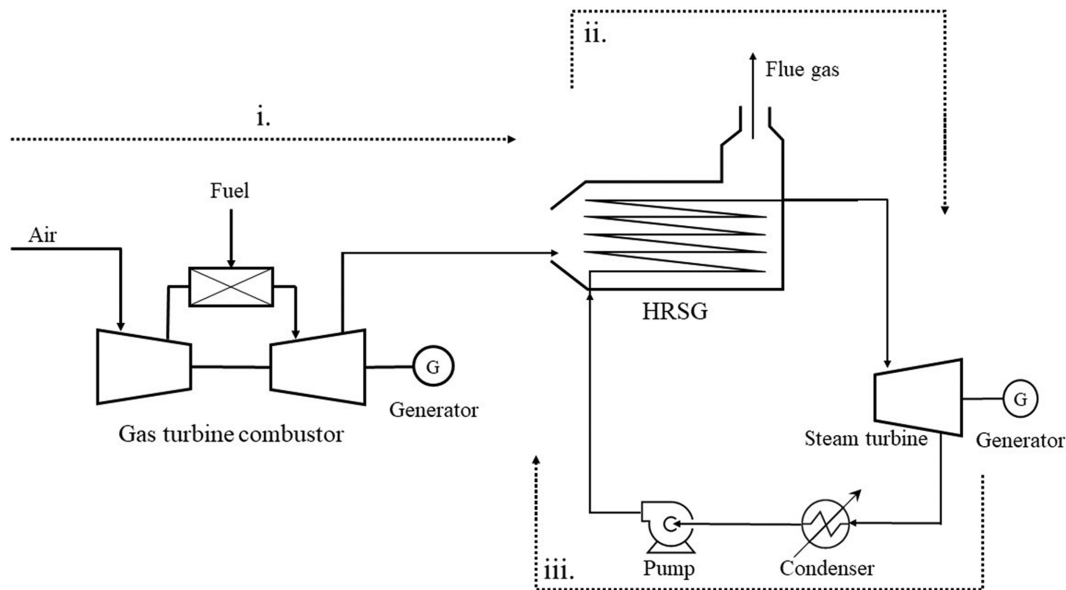


Fig. 5. Schematic illustration of the CCPP.

bine is utilized in a steam turbine. The gas turbine supplies most of the heat, which is called the topping cycle in CCPP. The exhaust gas discharged from the gas turbine is used to produce steam through a heat recovery steam generator (HRSG), and the steam turbine uses this steam to generate extra power [19,22]. The HRSG is a steam generator that produces steam by utilizing exhaust gas. For this reason, the efficiency of the CCPP is higher and the CCPP is generally used for generation of large loads on power.

A schematic diagram of a CCPP is shown in Fig. 5. The following is a brief description of the plant operation. (i) Atmospheric air is compressed by a compressor and pressurized air enters the combustion chamber, where it mixes with fuel and undergoes combustion. The gas that is heated up through the combustion chamber enters the turbine and generates power. (ii) Then, the exhaust gas from the gas turbine moves to the HRSG. The HRSG generates steam by utilizing exhaust gas, and the remaining flue gases in the HRSG are sent to the atmosphere through stacks. (iii) Lastly, the generated steam operates a steam turbine to generate power. The exhaust steam discharged from a steam turbine is fed to the condenser and the condensed water is pumped back to the HRSG to generate steam [24].

As mentioned, utility systems are necessary to operate the topside process by supplying the cooling medium, heating medium, and power, and the following need to be considered for designing the utility system. Firstly, the utility system should be flexible and sustainable because of continuously changing operating conditions (e.g., surroundings and properties of the feedstock). Secondly, the utility supply is limited because of the isolated location from the land. Thus, utilities required to operate the process should be self-sufficient. Thirdly, the layout of the system should be considered because spare parts of the equipment cannot be placed in offshore plants due to the limits of space and weight [25]. Lastly, the sources for any possible accidents that may occur should be prevented in advance. This is because the offshore plant is located in a corro-

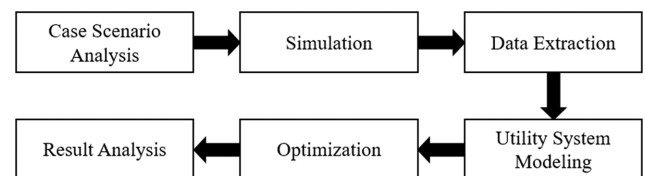


Fig. 6. Schematic of the utility system design framework.

sive surrounding (e.g., high humidity, salts, etc.), where they can be involved in accidents with high probability. For these reasons, it is important to optimize the utility system to increase thermal efficiency and prevent potential accidents. In this study, the utility systems are designed by considering these constraints.

METHODOLOGY OF MODELLING AND OPTIMIZATION

In this research, the optimization of the utility system involved the following procedure, as shown in Fig. 6. Firstly, various operation scenarios through operating life cycle were analyzed and divided into cases. In this work, 11 cases of the gas well and 6 cases of the oil well were considered. Secondly, each case was implemented to the topside process model, and the utility consumption data was obtained from the material and energy balances. Thirdly, the utility system was designed to satisfy the required utility loads based on the consumption data. When the utility system modeling was finished, the utility system was optimized to maximize thermal efficiency, meeting operating constraints. Lastly, the optimization results were analyzed and validated.

1. Topside Modeling and Utility Consumption Analysis

Total operation life cycle is divided into several particular periods based on the operating conditions. Oil and gas wells have a life cycles such as the start-up, plateau production, and decline stages.

During start-up stage, there is much crude oil and gas in the well, and its production rate increases gradually as more wells are drilled. After a while, the well's phase turns into the plateau production stage that has peak crude oil and gas production rate. This stage lasts about 2-3 years or longer in the case of a larger field, and the production rate becomes stable and maintains. Lastly, when oil and gas well is in the decline stage, the production rate falls at a rate of 1% to 10% per year. This is because the H₂O content in the well is getting bigger. When the oil or gas well is no longer producing crude oil and gas product, the life cycle of the well ends.

A total of 11 different cases were considered as the operation scenario of the gas well. The gas wells consist of two separate manifolds, which we named A and B manifolds for convenience. Case 1 shows that only gas fluids with high pressure (HP) and LT in A manifold arrive to the processing facility. The processing facility gathers gas from wellheads. It pretreats water, sand, and other impurities to improve production performance. Case 1 yields the maximum condensate flow that has mainly crude oil having greater than 40 API°. Case 2 indicates that only gas fluids with HP and LT in A manifold arrive to the processing facility and yields the maximum liquid (i.e., oil and water) flow. In Case 3, the only gas fluids with HP and HT in A manifold arrive to the processing facility. Case 4 shows that only gas fluids with low pressure (inlet compression required) and LT in A manifold arrive to the processing facility. In Case 5, the gas fluids with low pressure (LP) and LT in A manifold arrive to the processing facility, being processed in two processing facility process trains. Also, gas fluids with HP and LT

in B manifold arrive to the processing facility, being processed in one processing facility process train. Case 6 shows that gas fluids with LP and LT in A manifold arrive to one processing facility process train. Also, gas fluids with LP and LT in B manifold arrive to two processing facility process trains. Case 7 indicates that the only gas fluids with LP and HT in A manifold arrive to the processing facility. Case 8 shows that the gas fluids with LP and HT in A manifold arrive to the processing facility, being processed in two processing facility process trains. Also, gas fluids with HP and HT in B manifold arrive to the processing facility, being processed in one processing facility process train. Case 9 indicates that gas fluids with LP and HT in A manifold arrive to one processing facility process train. Also, gas fluids with LP and HT in B manifold arrive to two processing facility process trains. In Case 10, only gas fluids with LP and LT in B manifold arrive to the processing facility, being processed in two processing facility process trains. Case 11 shows that only gas fluids with LP and HT in B manifold arrive to the processing facility, being processed in two processing facility process trains.

Table 2 presents flowrate, pressure, and temperature of each case in the gas well. It is assumed that the flowrate does not change much and remains similar for a whole operation period. The pressure maintains at 8,817 kPa in the start-up stage, and then 4,417 kPa in plateau production, and it declines at the end of operating life cycle. The temperature fluctuates during the operation period. The topside process is constructed and implemented using data in Table 2. Once the simulation model of the topside process was

Table 2. Feed conditions for each case in gas well

Cases	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Flow rate [t/h]	2,508.75	2,515.37	2,512.80	2,570.15	2,545.86	2,435.10
Pressure [kPa]	8,483	8,483	8,483	4,417	4,417	4,417
Temperature [°C]	46.17	40.01	89.98	36.35	42.68	41.43
Cases	Case 7	Case 8	Case 9	Case 10	Case 11	
Flow rate [t/h]	2,480.53	2,570.68	2,570.68	2,525.31	2,433.40	
Pressure [kPa]	4,417	4,417	4,417	4,417	4,417	
Temperature [°C]	60.01	89.97	89.97	76.01	58.93	

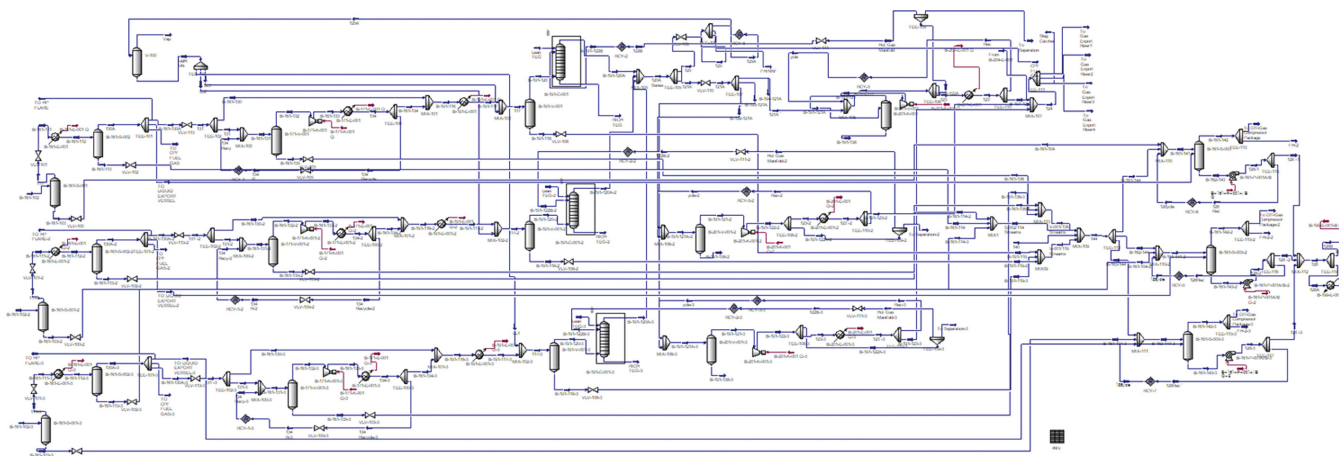


Fig. 7. Schematic illustration of topside process of gas well for case 1.

developed, the simulation results were compared with the actual engineering project data for validation, and it proved that the results agreed well with the existing data.

The offshore field has a complex process. Pretreatment systems (e.g., acid gas removal, dehydration systems, and mercury removal unit) are generally required in the topside process because drilled feeds from the deep sea have high amounts of impurities that deteriorate the efficiency of the process. Secondly, a compression system is required because the feeds with LP from the subsea that pass through the riser need to be pressurized to reach a storage tank [26].

Fig. 7 shows the overall topside process configuration of gas well for case 1, which is implemented in Aspen HYSYS (Version 10) that is one of commercial process simulators for chemical plants. Feed is divided into three flows and they enter the topside process. The process begins with the pretreatment of feed. Generally, the acid gas removal unit (AGRU) should be installed in front to reduce CO₂ and H₂S, which cause severe corrosion in pipe and equipment in the feed. However, the AGRU was not included in this model, following the engineering data. Each feed is immediately pressurized through the compressor and cooled down through the heat exchangers. After the pressurization process, the feeds are dehydrated in the glycol dehydration column. Because H₂O in the feed might produce water ice and hydrate that causes physical damage to equipment, it must be removed through the dehydration process. Then, dehydrated feeds are transported via the compressor and the heat exchanger. Lastly, the feeds flash, separating into the liquid phase and vapor phase in the flash drum, and separated products are transported to the storage tank. Due to the changes of the feed stocks, there are changes of equipment operation depending on feed conditions. As shown in Table 3, the utility consumptions are estimated based on each case. The cooling medium and power demand vary widely, and these various results are used in utility system modeling.

Specifically, case 9 is heavy load, which has the largest power demand among all cases, and case 10 is light load, which has the smallest power demand. When the utility system is designed, both heavy and light loads should be considered so that we can reduce

an operating cost, increase the efficiency of the utility system, and ensure the safety of the offshore plant [23]. In this study, the utility system was constructed to accommodate both the heavy load and light load.

The topside process simulation of the oil well is implemented in the same way as a gas well. The six cases are considered for the operation of the oil well. Case 1 is the case of rich oil that has the maximum rate of extraction petroleum reaches, and it occurs when the oil flow rate is still at a plateau and produced water has increased to its highest simultaneous flow rate. Case 2 is the rich oil separation malfunction case. For this case, it is intended to ensure that higher levels of carryover of water with the oil can be accommodated with all equipment downstream, including the crude oil heaters, second-stage separators, wash tanks, and condensate storage tank when poor oil and water separation performance of the first-stage separate occurs. This case serves as the sizing basis for the crude oil heaters and an operating case for the second-stage separator. Case 3 is the rich gas case that has the maximum gas production rate, and it occurs when the gas flow rate is maximum based on the production profile. Case 4 is the rich gas design case that is similar to the rich gas case, but fuel gas is taken from downstream of the glycol contactor. This case gives maximum throughput to the compression trains and sized the medium pressure (MP)/HP compression trains. Case 5 is the rich liquid case, and it occurs when gross liquid (oil and water) is maximum. Case 6 is the rich water case, and it occurs when produced water is maximum.

Table 4 summarizes flowrate, pressure, and temperature for each case in the oil well. The flowrate does not change much and remains similar for a whole operation period, and the pressure also maintains 12 kPa until the rich water case. The temperature changes during the operation period.

Fig. 8 shows the overall topside process configuration of the oil well for rich oil case. The topside process of the oil well is implemented using feed conditions in the oil well using Aspen HYSYS. Feed is divided into two flows and enters the topside process. These feeds are separated by vapor, liquid, and water phases in the three-phase separator. Then, another separator divides the feed into the vapor phase and liquid phase, and the vapor phase feeds are pres-

Table 3. Utility consumption during operating periods in the gas well

Utility type	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Cooler [MW]	109.07	101.52	203.30	198.97	155.95	187.12
Electricity [MW]	75.74	73.30	74.79	133.25	113.07	139.65
Utility type	Case 7	Case 8	Case 9	Case 10	Case 11	
Cooler [MW]	300.98	265.69	292.77	91.50	153.30	
Electricity [MW]	140.83	119.49	146.78	72.16	87.29	

Table 4. Feed conditions for each case in oil well

Cases	Rich oil	Rich oil separation malfunction	Rich gas	Rich gas design	Rich liquid	Rich water
Flow rate [t/h]	2,612.77	2,610.32	2,056.84	2,058.48	2,935.75	2,279.67
Pressure [kPa]	12	12	12	12	12	12
Temperature [°C]	29.80	29.80	59.20	59.20	29.90	29.90

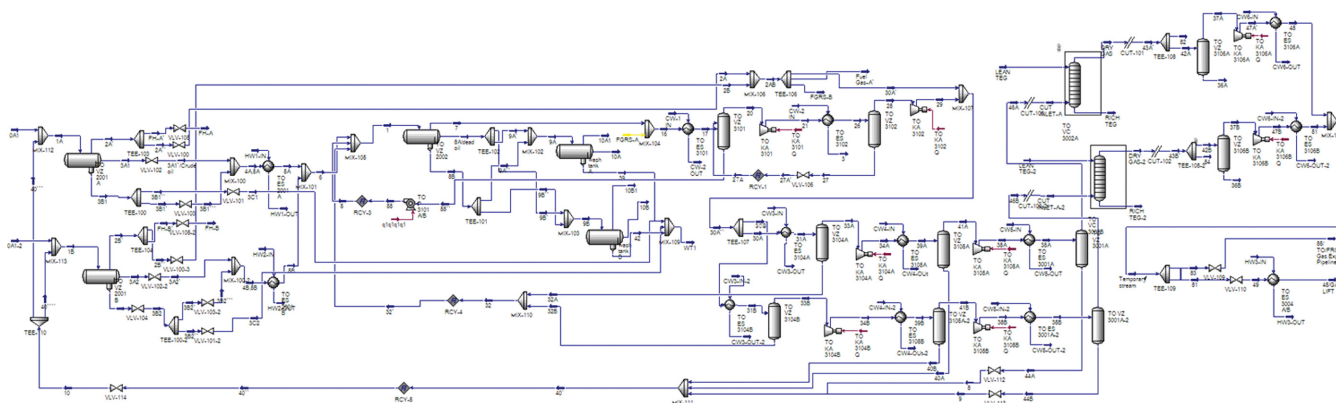


Fig. 8. Schematic illustration of topside process of oil well for rich oil case.

Table 5. Utility consumption during operating periods in the oil well

Utility type	Rich oil	Rich oil separation malfunction	Rich gas	Rich gas design	Rich liquid	Rich water
Hot water [MW]	36.48	43.81	2.25	2.24	33.15	6.35
Cooling water [MW]	67.59	68.01	77.45	82.74	66.36	51.84
Electricity [MW]	82.45	82.67	84.55	88.39	81.37	67.83

surized by the compressors. The pressurized stream enters the glycol dehydration column to reduce H₂O using mono-ethylene glycol, so that the hydrate can be prevented. Lastly, product streams are transported in the storage tank through the compressor and heat exchanger. Other oil well cases have the similar configuration, but equipment operation might change depending on the feed condition.

As shown in Table 5, the utility consumptions are calculated depending on the cases. The topside process of the oil well uses a heating medium that is not used in the gas well, and Table 5 summarizes the utility consumption during the operating periods in oil well. The cooling medium and power demand also vary widely, and these various results are used in utility system modeling. Specifically, the rich gas design case has the highest consumption of power, while rich water case is light loads considered in utility system modeling.

RESULT AND DISCUSSION

1. Utility System Design in Offshore Plant

According to the analysis results as shown in Table 3, it was noticed that mainly two ranges of power demands (i.e., 70-90 and 110-150 MW) should be considered in the topside process of the gas well through the operating life cycle. For the selection of right type of gas turbines that satisfy the power demands for all cases with high thermal efficiency, the following aspects were considered in this work.

- 1) At least three gas turbines should be installed and operate in parallel.
- 2) Three gas turbines operate in parallel to meet the highest power demand, while two of them for the lowest power demand.
- 3) High thermal efficiency of gas turbines should be maintained for all cases.

4) HRSG and steam turbines shall be integrated with gas turbines to supply additional power.

5) The operating loads of gas turbines and steam turbines are optimized to minimize total fuel consumption for each case, maintaining high thermal efficiency of the utility system.

By considering all the aspects above, we concluded that three gas turbines (two LM 2500+G4 and one LM 6000 PF+), HRSG and two steam turbines (back pressure turbine and extraction turbine) are used to produce the power for topside process in gas well as shown in Fig. 9.

The utility system for the gas well is simulated using Aspen Utilities Planner (AUP, version 8.8), as shown in Fig. 9. The engineer can use AUP to design the utility system and perform steady state simulation. Furthermore, the AUP allows its users to develop operation strategies of the plant-wide utility system by using an optimization tool. For optimization, it uses a mixed integer non-linear programming (MINLP) so that it can handle broad ranges of optimization problems. In this case, three gas turbines are installed parallel in the utility system for gas well, and the size of each turbine should be considered, especially when power demands change dramatically between the operating cases. Since the topside process of the gas well does not have a heating process, the HRSG and steam turbines are installed to utilize an exhaust gas. The fuel and air enter the gas turbine, which produces power and exhaust gas. If only gas turbines are installed, the exhaust gas is discharged into the atmosphere. On the other hand, the exhaust gas is utilized to produce steam in HRSG. The once-through steam generator (OTSG) is used in the system, which is a type of HRSG that plays a role as a good compromise in many ways between weight and efficiency for offshore plants, although the efficiency of the OTSG is lower than that of the typical HRSG. An OTSG is a continuous tube heat exchanger, in which the preheating, evaporation,

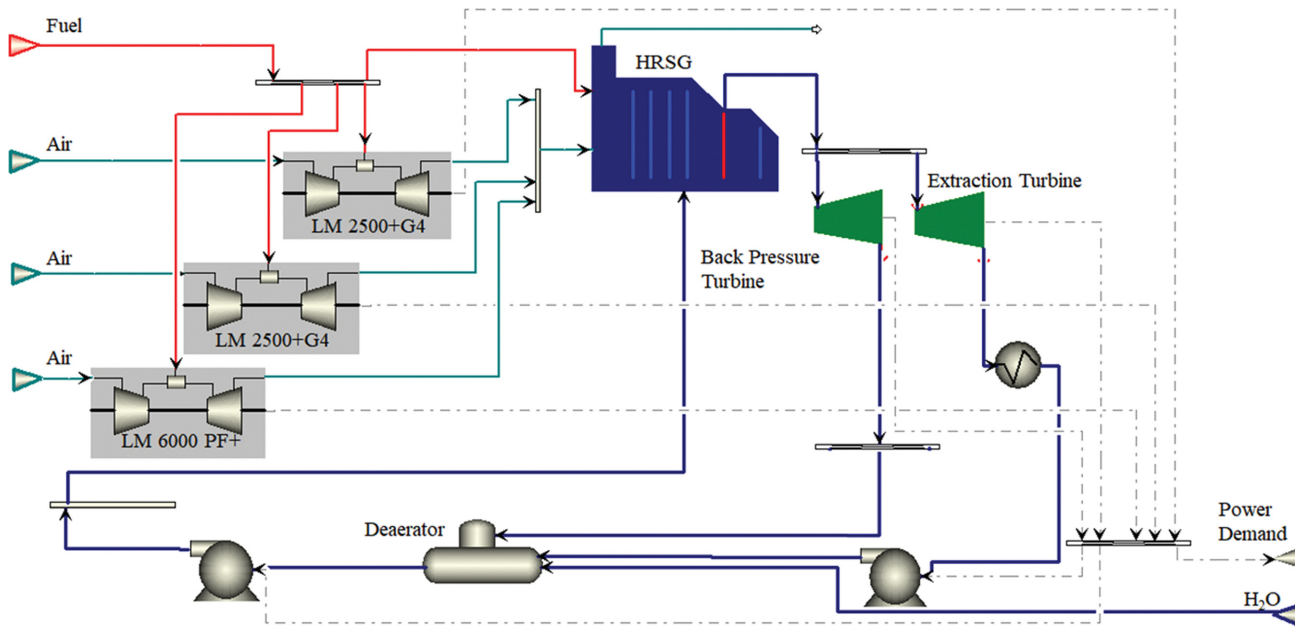


Fig. 9. Utility system of gas well using AUP.

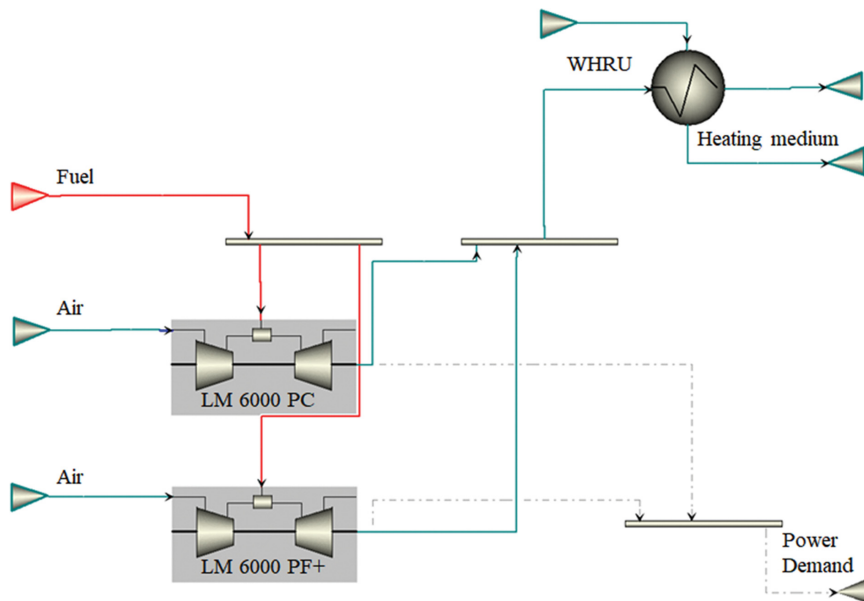


Fig. 10. Utility system of oil well using AUP.

and superheating of the feedwater take place. Unlike conventional HRSG, OTSGs have no defined economizer, evaporator, or superheater sections and steam drums, and the absence of the inter-equipment provides advantages in terms of weight and space [27-29].

The exhaust gas transfers the heat to H₂O that generates steam with HT. The steam is used to generate power by operating the steam turbine. [30]. In general, two different types of steam turbines are used to produce power in the utility system. The steam turbines available in offshore plants are more compact and have a lower weight [31]. On the other hand, an extraction condensing steam turbine is used to produce extra power, and the back-pressure steam turbine is used to heat up a makeup H₂O by supplying

LP steam to the deaerator. After generating extra power, the steam is condensed to H₂O, pressurized through the pump, and enters the HRSG again in a closed loop.

Compared with the gas reservoir process, the oil well process does not have significant amount of power demand, having relatively small fluctuation. The power demand for these cases is between 67 and 88 MW. Furthermore, the topside process of oil well has a heating process, and it can provide a heating medium. Therefore, a WHRU would be required to produce hot water as a heating medium. Following the same approach as the gas well, we considered the total number of gas turbines for installation and its types. Fig. 10 shows the utility system of the oil well that we developed.

Two gas turbines are installed in parallel, which are sufficient to meet the power demands. The steam turbine is not used because extra power generation is not required. The WHRU is installed to produce the heating medium instead of the HRSG and steam turbine. The exhaust gas enters the WHRU, and the heating medium is produced to supply the heat, where heat is required.

2. Optimization of the Utility System in the Offshore Plant

Based on utility consumption in the topside process and the design criteria of the utility system, the operation conditions (i.e., operating load of each gas turbine and steam turbine) of the utility system are optimized, considering all feasible cases. The AUP is used to optimize the utility system, using a genetic algorithm (GA) for MINLP optimization.

The main objective of the optimization is to maximize power generation efficiency, having minimal fuel consumption. Table 6

shows the objective function and constraints for optimization.

The fuel injected into the gas turbine is assumed to be NG. The offshore plant produces and supplies its own fuel. In the topside process, a portion of fuel gas is used in the utility system. NG from the well is widely used as fuel because it has advantages (e.g., combustion temperature, impurity composition, operation, and maintenance) over other types of fuels [32]. Complete combustion is assumed in the modeling.

The gas turbines and HRSGs are mainly considered for optimization in this work. The efficiency of these units varies greatly depending on the conditions. Specifically, the efficiency of the gas turbine depends on the load. To maintain the high thermal efficiency of the gas turbine, the loads should be kept high. Furthermore, in the HRSG used in the process, the pressure and temperature of the steam and the pinch temperature have a significant effect on effi-

Table 6. Objective function and constraints for optimization

Objective function		
Fuel consumption [t/h]	LNG 49.5 MJ/kg	[Fuel type] [LHV]
Optimized variables		
	Each gas turbine load Ratio of Extraction/Backpressure turbine operating loads	
Constraints		
Power demand [MW]	Depending on power demands	
Parallel generation	3 in maximum [24]	
HRSG pinch temperature	35 K	
Steam conditions	673.15 K, 26 bar	
Steam injection ratio	Between extraction and back-pressure, for deaeration	

Table 7. Optimization result in the gas well cases

Gas well cases	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Electricity [MW]	75.74	73.30	74.79	133.25	113.07	139.65
Steam production [t/h]	65.64	63.34	64.55	118.54	95.23	123.31
Fuel consumption	0.147	0.147	0.147	0.143	0.139	0.142
CO ₂ emission	0.405	0.405	0.406	0.394	0.382	0.391
Turbine load [%] (LM2500+G4)	0	0	0	48.89	0	63.46
Turbine load [%] (LM2500+G4)	16.89	11.69	15.03	48.89	100	91.26
Turbine load [%] (LM6000 PF+)	100	100	100	100	100	100
Steam injection ratio (Extraction/Backpressure)	7.66	7.66	7.66	7.66	7.66	7.66
Efficiency [%]	49.35	49.36	49.31	50.68	52.34	51.06
	Case 7	Case 8	Case 9	Case 10	Case 11	
Electricity [MW]	140.83	119.49	146.78	72.16	87.29	
Steam production [t/h]	124.29	105.9	128.56	62.12	75.43	
Fuel consumption	0.142	0.145	0.141	0.147	0.145	
CO ₂ emission	0.355	0.400	0.387	0.405	0.398	
Turbine load [%] (LM2500+G4)	91.26	100	85.5	0	0	
Turbine load [%] (LM2500+G4)	66.09	10.66	85.5	9.4	42.31	
Turbine load [%] (LM6000 PF+)	100	100	100	100	100	
Steam injection ratio (Extraction/Backpressure)	7.66	7.66	7.66	7.66	7.66	
Efficiency [%]	51.16	49.91	51.64	49.32	50.22	

ciency. Hence, the steam conditions and pinch temperature are constrained as shown in Table 6 [31]. If the process requires steam, the distribution of load between two steam turbines should be separated accordingly [33].

The optimization of the utility system is performed in the AUP. All cases that occur during the operating periods are considered for optimization of the utility system. Importing of electricity is not considered, and only the production of electricity through fuel is considered in this work.

Table 7 shows the optimization results of gas well cases: the electrical production, steam production, fuel consumption, CO₂ emission, and efficiency. Table 7 shows wide power demands from 60 to 140 MW during the operating periods. Cases 1, 2, 3 are start-up stages and have relatively low crude oil/gas production so that power demand is not high. However, after a certain period, the operating condition changes to the plateau production stage, and the utility system gets into cases 4, 5, 6, 7, 8, 9. The plateau production stages require relatively high power demand due to the increase in crude oil and gas production. The decline stages (i.e., case 10, 11, 12) are in the last stage of the operating periods. The gas well in this stage have a low production of crude oil, and power demand is relatively low compared with other stages.

According to the optimization results, every case satisfies the power demand, maintaining high efficiency, although power demand changes dramatically during the operating periods. As mentioned in the introduction, the single power generator has an efficiency of 38–41%, while the CCPP used in our optimized utility system of the gas well has higher efficiency, ranging from 49–52%. Furthermore, as the thermal efficiency reaches a maximum in each case, fuel consumption is reduced and CO₂ emission is minimized accordingly.

Table 8 shows the optimization results of oil well cases. In Table 8, there are power demands from 40 to 60 MW during the operating periods. The rich oil case presents relatively high power demand among the cases, and the highest steam requirement. Rich oil separation malfunction case has similar power demand to rich oil case, but the steam production is significantly lower than other cases,

which might cause a difference in efficiency. The rich gas case also indicates relatively high power demand, but the steam production is quite low. The rich gas design case presents the highest power demand and low steam production. The rich liquid case has a similar result to the rich gas case. Lastly, the rich water case requires lower power demand and steam production than rich oil case because it has a low crude oil and gas production rate from the well.

According to the optimization results, the utility system of the oil well satisfies the power demand, having efficiency between 41 to 58%. In fact, the efficiency fluctuates as the oil well process uses a heating medium to provide heat to the process. The CO₂ emission can be minimized as the thermal efficiency increases in each case.

CONCLUSIONS

Utility systems were developed using Aspen HYSYS and AUP. We first developed a simulation of the topside process in the offshore plant using Aspen HYSYS. Because the operation of the topside process varies depending on feed conditions, the utility demands were measured in each case. The utility consumption varies greatly in cases, and the utility systems were modeled and optimized using the AUP to accommodate the power demands. The utility systems are designed by utilizing parallel gas turbines, CCPP, and WHRU, and the operating variables such as operating load of each gas turbine and steam turbine are optimized based on the utility consumption data from the Aspen HYSYS. For optimization, the number of turbines either in operating or holding modes and its utilization rate in operating mode are optimized to maximize the thermal efficiency of turbines, minimizing total fuel consumption for each case. Furthermore, the size of gas turbines and combination of its installation were optimized by considering all cases. The coupling of Aspen HYSYS and AUP provides robust performance in modeling and optimizing the utility system. The optimization results showed that the designed utility system has higher thermal efficiency than unoptimized case. For example, a single power plant shows its thermal efficiency below 41%, while

Table 8. Optimization result in the oil well cases

Oil well cases	Rich oil	Rich oil separation malfunction	Rich gas
Electricity [MW]	82.45	82.67	84.55
Hot water [t/h]	36.48	4.38	2.25
Fuel consumption	0.182	0.182	0.181
CO ₂ emission	0.502	0.502	0.497
Turbine load [%] (LM6000 PC)	100	100	100
Turbine load [%] (LM6000 PF+)	77.79	78.21	81.83
Efficiency [%]	57.51	41.98	41.34
	Rich gas design	Rich liquid	Rich water
Electricity [MW]	88.39	81.37	67.84
Hot water [t/h]	2.24	3.31	6.35
Fuel consumption	0.178	0.183	0.193
CO ₂ emission	0.490	0.503	0.529
Turbine load [%] (LM6000 PC)	100	100	100
Turbine load [%] (LM6000 PF+)	89.21	75.71	46.69
Efficiency [%]	41.88	41.36	41.31

the optimized utility system shows 49-52% for gas well and 41-58% for oil well. Furthermore, the designed utility system is flexible enough to accommodate the power demand during total operating periods. As a result, it can save capital cost for the utility system, operating cost for fuel consumption, and reduce the CO₂ emission rate accordingly. This approach for the design of the utility system can be applied to the offshore plant easily.

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ABBREVIATIONS AND ACRONYMS

AUP	: aspen utilities planner
CCPP	: combined cycle power plant
GHG	: greenhouse gas
HEN	: heat exchanger network
HP	: high pressure
HT	: high temperature
HRSG	: heat recovery steam generator
LNG	: liquid natural gas
LP	: low pressure
LT	: low temperature
MINLP	: mixed integer nonlinear programming
MP	: medium pressure
NG	: natural gas
WHRU	: waste heat recovery unit

Nomenclature

LHV	: lower heating value [MJ/kg]
\dot{m}_f	: mass flow of fuel [kg/s]
Q_C	: heat of cold source [J]
Q_H	: heat of hot source [J]
T_C	: temperature of cold source [K]
T_H	: temperature of hot source [K]
$\dot{W}_{compressor}$: work of compressor per second [W]
\dot{W}_{cycle}	: work of cycle [W]
\dot{W}_{GT}	: work of gas turbine per second [W]
\dot{W}_{ST}	: work of steam turbine per second [W]
$\dot{W}_{turbine}$: work of turbine per second [W]

Greek Letters

α	: fuel mass conversion factor [kg CO ₂ /kg fuel]
η_{cycle}	: efficiency of cycle
η_g	: generator efficiency
η_m	: mechanical efficiency

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