An Approach For Selecting CO_2 Removal Technology In Indonesia's Upstream Natural Gas Industry Using AHP Method

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Impurities are commonly found in natural gas which is produced from reservoirs deposit. The predominant impurities come in CO_2 forms. Hence, the selection of proper CO_2 removal technologies is a significant step in process engineering as it strongly affects the size of CAPEX and OPEX. However, the selection of the CO_2 removal process is not always trivial and further it must be conducted in the beginning of the project feasibility study. Currently, there are several CO_2 removal technologies including absorption, adsorption and membranes. Considering their advantages and limitations, there is a need to analyse the relationship between the CO_2 removal cost with the required product gas, impurities, flow capacity, geographical factor and CO_2 tax in Indonesia. Thus, these criteria are evaluated through the multi-criteria decision-making (MCDM) technique for selecting the most suitable technology for removing CO_2. In this study, Analytic Hierarchy Process (AHP) is chosen and applied to evaluate the significance of each criterion. The results showed that absorption using the amine system is frequently used in Indonesia's upstream natural gas industry. Furthermore, the use of the adsorption method (pressure swing adsorption) for a low-quantity gas feed also showed good results. The use of AHP method for selecting CO_2 removal technology in Indonesia's upstream natural gas industry can be used by investors and policymakers as a useful pre-investment tool analysis in developing new fields. The current proposed method aims to screen the best CO_2 removal technology by taking into accounts technical performance, revenue and cost, as well as reducing emissions.

Keywords: AHP; CO_2 removal technology; Natural gas; Upstream industry

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1. Introduction

Natural gas is considered to be a cleaner fuel compared to coal and crude oil. According to Balzani and Armaroli [1], when combusted to reach the same energy content, the CO_2 emission factor of natural gas is 41 and 26% less than that of coal and oil, respectively. Natural gas encourages low-and zero-emission energy use, making it one of the most attractive fuels and this makes the demand for global natural gas increases rapidly [2]. In 2021, globally, there is a 5.3% increase in demand for natural gas [3].

Raw natural gas is extracted from the wells as a gaseous mixture with different range of composition depending on the well characteristics such as well depth, type of reservoir, and the geology of the location. As a consequence, raw natural gas often contains impurities. The main impurities are in the form of CO_2 and H_2S known as "acid gases" because they can react with water to form acidic solutions [4]. The acidic solutions can result in corrosion in all metal-based equipment such as pipelines, vessels, and rotating. Moreover, in LNG plants, CO_2 can affect freeze and block the piping system at a very low temperature. Thus, eventhough the CO_2 gas comes in very small quantities, it is very undesirable and must be removed. The separation process of CO_2 from natural gas (sweetening process) has been a standard practice in natural gas processing facilities. This is conducted to fulfil the required sales gas, specifications of pipes, and effective liquefaction process of natural gas to liquefied natural gas (LNG). There are numerous technology available for CO_2 removal including e.g. adsorption, absorption, membrane [5–7].

Selecting proper CO_2 removal technology can be a "turn the tables" step that will largely influence the project feasibility study. However, the selection of the CO_2 removal process is not always easy and must be conducted at the beginning of the project feasibility study. In addition, there has been a growing interest to invest in more eco-friendly technology as a part of efforts to decrease CO_2 emissions to the atmosphere as well as to minimize global warming. The CO_2 gas can be utilized as a technological fluid that is injected into oil reservoirs in the enhanced oil recovery (EOR) technology [8]. In terms of finances, the existence of CO_2 in natural gas can reduce the energy value (heating value). The energy value (heating value) is a major factor in the Gas Sales Agreement (GSA) to determine the selling price of natural gas.

Utilization of the captured CO_2 is successfully conducted in some sectors including chemicals, oil and power, food, pharmacy, pulp and paper, and steel industries. According to Koytsoumpa et al. [9], the utilization of CO_2 can be classified as (1) resource recovery (examples: Enhanced Coal-Bed Methane Recovery and Enhanced Oil and Gas Recovery), (2) captive (integrated process) using CO_2 as an intermediate product in the manufacturing chain with no external sources and (3) non-captive or merchant use [9].

In the traditional approach, the selection of the CO_2 removal process is very simple. The difference in the composition of CO_2 in the inlet and the outlet could be an adequate parameter to find the appropriate CO_2 removal technology (as shown in Fig. 1). However, some technologies seem to have the same application range and rigid boundaries resulting in an easily wrong interpretation. Besides that, this criterion appears to be insufficient because it does not take into account the specifications of the processed gas that must be reached [10]. Other factors influencing the selection of CO_2 removal technologies are the contaminant concentrations in the feed gas, the contaminant removal level, the product purity required, the feed gas flow rate and conditions (water content, pressure, temperature), and the Acid Gas Removal Unit (AGRUs) required for simultaneous removal of H_2S. In addition, the energy requirements, feasibility, and costs of CO_2 and N_2 removal processes need to be considered in the selection of CO_2 removal technologies [11].

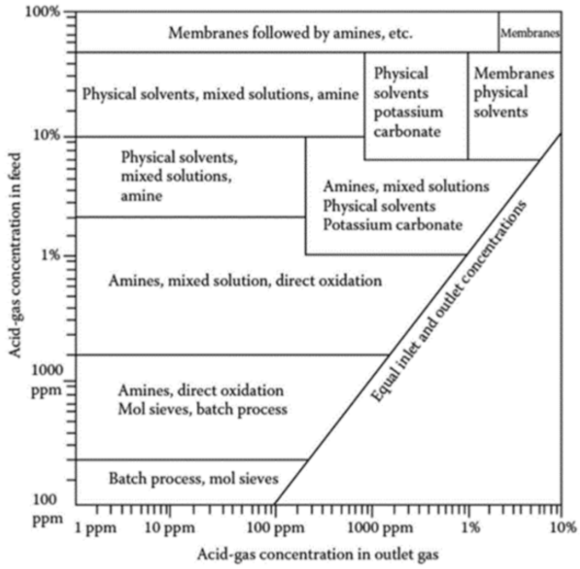

Fig. 1. Diagram of the traditional approach for selecting CO_2 removal technology [10]

Many studies have been conducted to evaluate and select CO_2 removal technology. The chemical absorption method using amine (MEA) is the most established CO_2 removal technology in this industry. Evaluation of the most appropriate CO_2 removal technologies in other industry such as cement industry has been reported in the literature by using simulation and comparing the criteria with the chemical absorption methods using amine (MEA) as the benchmark [12]. The combination of the Analytic Hierarchy Process (AHP) and the Weighted Sum Model (WSM) is used to analyse the MEA method and calcium looping post-combustion capture and oxyfuel technologies implementation for selecting the most appropriate CO_2 removal technology in the Portuguese cement industry [13].

There are numerous existing methodologies used for evaluating CO_2 removal technologies regarding all criteria/factors (tangible and intangible) to select an appropriate technology applied in AGRU. The selection of CO_2 removal technologies must consider several criteria/factors. Multi-criteria decision-making (MCDM) approach can be used as a method for ranking and evaluating the alternatives criteria to make decisions. Some techniques used in MCDM are AHP, WSM (Weighted Sum Model), ELECTRE, WPM (Weighted Product Model), PROMETEE, TOPSIS (Technique for the Order of Preference to the Ideal Solution), and ANP (Analytical Network Process). When selecting or ranking from a large number of alternative groups, the AHP is a compensatory strategy that assists decision-making in contexts of both certainty and uncertainty. An AHP approach analyses paired personal judgments at each hierarchical level and according to the next level. It is a set of goals, criteria, attributes, and alternatives in a hierarchical order [14].

Based on our literature survey, a study which reported a methodology to select and evaluate CO_2 removal technologies in Indonesia's upstream natural gas processing is not yet available. In general, there are several CO_2 capture technologies that currently exist in Indonesia's upstream natural gas industries such as absorption (physical and chemical absorptions) and pressure swing adsorption (molecular sieve). In addition, there is an increasing interest to utilize membranes as an emerging technology for CO_2 removal. Each CO_2 removal technology has its advantages and limitations relative to others. A hybrid technology which integrates two different technologies in a single unit operation seems to have greater potential and more economical in comparison to one technology stand-alone [15]. However, a detailed methodology to implement hybrid technology is not yet available in the literature because it needs detailed calculations for each technology to combine. Therefore, a useful tool for decision-makers is needed to select appropriate CO_2 removal technology in the natural gas processing industries.

In the current study, several criteria/factors are demonstrated to be considered in selecting an appropriate CO_2 removal technology for a natural gas processing unit in Indonesia. The criteria/factors have been ranked, scored and detailed to facilitate the decision-makers to make an accurate analysis. Another scope of this study is expected to serve as a useful "tool" to select an appropriate CO_2 removal technology for a natural gas processing unit in Indonesia. In this study, the tool is developed based on design, operational, and maintenance experience in six natural gas fields in Indonesia using an AHP approach which analyses pairwise judgments at each hierarchy level. It is a set of goals, attributes, criteria, and alternatives in a hierarchical sequence. The present work is intended to complement the previous studies.

2. Methodology framework

2.1. Materials and collection of data for the main criteria

In this study, technical data on CO_2 removal technologies that has been implemented in oil and gas companies in Indonesia were collected via discussion and literature study. The literature study consists of well gas components, feasibility study, FEED, Authorization for Expenditure (AFE), Work Program and Budget (WP&B), and Plan of Development (POD) from several fields in Indonesia. The fields have been chosen by considering the variety of quantity of feed gas from low quantity to high quantity of raw gas as an inlet, variety of inlet CO_2 concentration and the geographical locations. A simple description of each field is shown in Table 1.

Detailed information about the performance of CO_2 removal technology in each field such as CO_2 content in the gas outlet, actual CO_2 removal technology, and characteristic contaminants is shown in Table 2.

2.2. Methodology framework

The AHP method has been developed by Thomas L. Saaty in 1980s and widely used in solving decisions in a case with many criteria/factors [15]. Fig. 2 shows the methodology framework for CO_2 removal selection, in which the framework is divided into three phases.

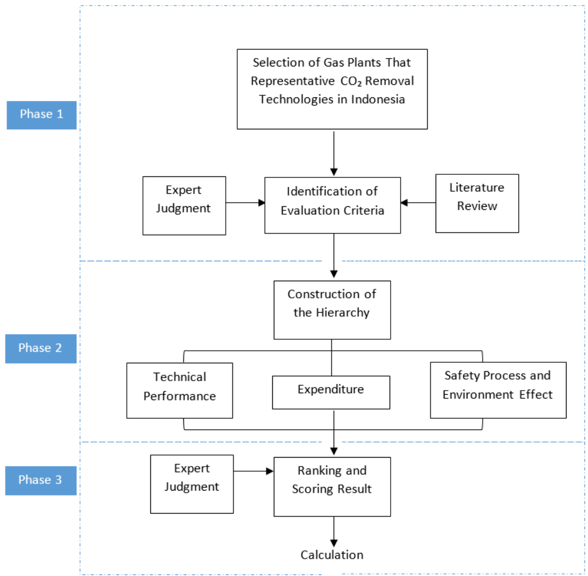

Fig. 2. CO_2 removal technology selection framework

Phase 1 – The selection of gas plants that represent various CO_2 removal technology in Indonesia's oil and gas industries was conducted in this phase. A potential list of each gas field/ gas processing plant could be identified by considering the variety of quantity of feed gas, CO_2 composition in raw gas as an inlet, contaminant and location. A detailed description of each gas field/gas processing plant was determined and leads towards the relevant criteria and sub-criteria. All criteria were gathered and divided into 3 main criteria including the sub-criteria and sub-sub-criteria based on literature review and consideration from discussions with experts in Indonesia's gas industries.

Phase 2 – In this phase, we assessed three main criteria

Table 1. Representative Field with CO_2 Removal Facility in Indonesia Oil and Gas Industry

Field	Location	Flowrate (MMSCFD)	CO_2 Inlet	Description
A	Onshore	3	51%	In Field A, 3 MMSCFD (51% CO_2) is delivered to the flare stack. The idea is to minimize emissions and gain some sales gas (increase additional sales gas) using Pressure Swing Adsorption (PSA) methods.
B	Offshore	40	23%	Field B is a mature offshore field and all facilities are connected by barge. This field is one of the largest offshore fields in the world that operates ESP (Electric Submersible Pump). Field B produces crude, condensate and sales gas.
C	Offshore	110	6%	Field C is located offshore in the Madura Strait East Java, about 65 km east of Surabaya and about 16 km south of Madura Island. The production facility is using FPSO designed for 110 MMscfd sales gas. The gas is separated from the liquids through three stages of separation. The sour gas is treated with an amine solution to remove all CO_2 and H_2S.
D	Onshore	100	25%	Field D is a carbonate reservoir and has specific impurities (solid suspension/mud). Field D produces sales gas and condensate.
E	Onshore	130	12%	Field E produces a sales gas (as a main product) that is distributed through pipelines to overseas buyers and also produces condensate.
F	Onshore	1,450	12.5%	Field F uses CO_2 removal to get the specification for LNG processing.

Table 2. The current CO_2 Removal Facilities in Oil and Gas Production in Indonesia

Field	Location	Raw Gas (MMSCFD)	Gas Inlet		Gas Outlet		CO_2 Removal Technology	Other Contaminant
			CO_2	H_2S	CO_2	H_2S		
A	Onshore	3	51%	-	<5%	-	Adsorption (Molecular Sieve)	
B	Offshore	40	23%	-	<5%	-	Absorption (Amines)	Wax and H_2S
C	Offshore	110	6%	0.44%	<5%	<10 ppm	Absorption (Amines)	process to molten
D	Onshore	100	25%	-	<5%	-	Absorption (Amines)	sulphur Solid
E	Onshore	130	12%	-	<5%	-	Absorption (Amines)	Suspension (Mud)
F	Onshore	1450	12.5%	-	50 ppm	-	Absorption (Amines)	

as well as to identify the sub-criteria for the implementation of CO_2 removal technology. Further, through literature review and experts' opinions, the sub-criteria were identified. Interviews were conducted to obtain responses to identify the sub-criteria in CO_2 removal selection. Discussions were held with the experts to reach a consensus on the sub-criteria in the study.

Phase 3 – The first thing to do in the ranking and scoring was to describe the main criteria/factors that will be evaluated to determine the hierarchy. Each criterion (it can be tangible or intangible components) in the hierarchy has a different role in CO_2 removal selection. When all component and component hierarchies were completed, the decision maker needs to evaluate and make a comparison of all technology candidates. In ranking and scoring, the decision maker could use their experience (expert judgments) or data to determine which component is more important than others.

2.3. Determination of Hierarchy Criteria

From the literature on CO_2 removal technology selection and review, the criteria and sub-criteria were extracted in accordance with their application and relevance to the natural gas processing industry in Indonesia. The determination of criteria and sub-criteria was conducted through discussion with the heads of the industrial project, contractors and academics, thus providing a complete approach from both industrial and academic perspectives. The criteria were finalized based on their applicability in the industry. This study determines three main criteria, including:

2.3.1. The technical performance of technology

In any CO_2 removal technologies, the main purpose of the technology was to achieve the best performance. Thus, technical performance factors remain the major considerations. Technical performance as the main criterion is divided into several sub-criteria which were considered in CO_2 removal technology selection and described below:

i. Technology maturity: The CO_2 removal technology is proven and has many populations in Indonesia.

ii. Operability: Fulfilment of the service and reliable performance capacity in normal and disruptive situations (length range of operating conditions including temperature, pressure, solvent, and feed gas flowrate).

iii. Reliability: The technology will operate in a defined environment without failure. The criteria are energy consumption and ease of operation.

iv. Performance: The degree to which the product satisfies acceptable levels of functionality and service. The CO_2 reduction percentage, along with the H_2S reduction, contaminant handling and turn-down ratio are also considered.

v. Flexibility: Flexibility is needed to manage the volatility of demand, and add products to existing operations and market variations. It has to be addressed by improving responsiveness and maintaining inventory and supplier base [16]. Hydrocarbon losses, type of product, spare part availability, delivery time, installation time and transportation include as sub-criteria.

2.3.2. *Expenditure unit (capital expenditure and operating expenditure)*

The expenditure unit is a significant criterion and determines how much money will be spent on CO_2 removal technology. The expenditure unit is divided into two criteria:

i. CAPEX (capital expenditure) - Capital expenditure is a total of direct equipment costs and indirect costs. Direct equipment costs depend on the size or capacity of equipment, while indirect costs are affected by the process facility cost. In other words, capital expenditure is a fund needed by an industry for acquiring, upgrading, and constructing physical assets which are plants, property, buildings, equipment, and technology. CAPEX is frequently used to carry out new projects or investations by an industry.

ii. OPEX (operating expenditure) - Operating expenditure is the cost borne by the industry to carry out its day-to-day operations (operating and maintenance). Operating expenditure is divided into fixed O&M costs (maintenance cost, operating labour, etc.) and variable O&M costs such as chemical, steam and maintenance equipment.

2.3.3. *Safety process and environmental effect*

Natural gas processing can generate pollution, thus companies need to have chemicals, processes and materials that do not damage the environment and preserve the ecology. There are two criterias for this aspect:

i. Hazardous material – This criteria include the use of hazardous materials or chemicals that may exist during the process.

ii. Emission – Discharge of gas or some ingredient into the air. In this study, scoring is based on the type of emission.

The detailed hierarchy of the AHP Method for CO_2 removal technology selection is shown in Fig. 3.

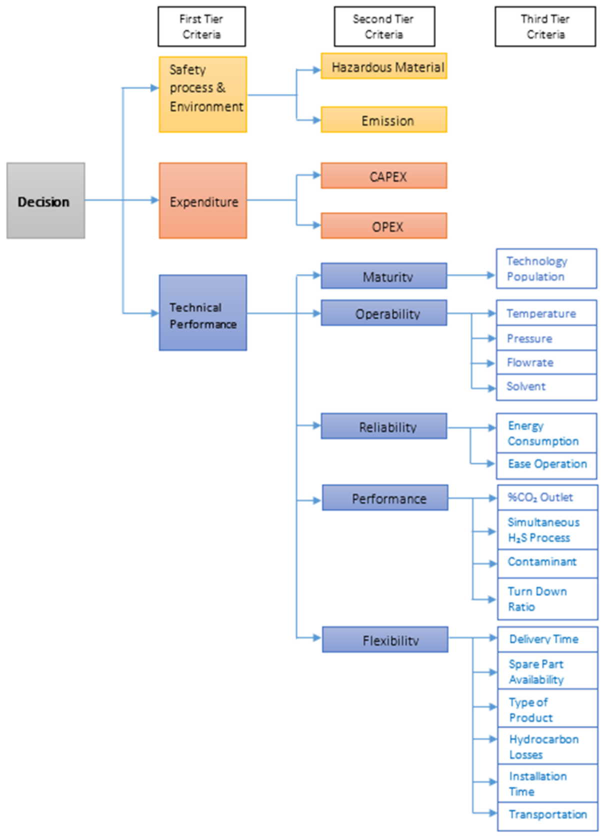

Fig. 3. Hierarchy Criteria on the AHP Method for CO_2 Removal Technology Selection

2.4. Ranking and Scoring

2.4.1. *Ranking of main criteria and sub-criteria*

All evaluations/responses were converted into numerical values and then processed to get the results. In this study, all main criteria were scored appropriately with the level of priority and declared in percentage, thus if one criterion has some sub-criteria, it would get the same treatment (level of priority and percentage). The determination of the percentage was different depending on the evaluation at each process unit. The main criteria that were scored were the technical performance for each technology, expenditure unit (capital expenditure and operating expenditure), and safety process & environmental effect. Table 3 shows the main criteria scores.

Table 3. Ranking of the Main Criteria (1^{st} Tier)

Criteria	weight (%)
Technical Performance	50
Expenditure Unit	40
Safety Process and Environment Effect	10

Based on Table 3, the technical performance has the biggest proportional percentage of all main criteria because it focuses to get the fittest CO_2 removal technologies, followed by expenditure unit and safety process & environmental effect.

The next step is scoring for sub-criteria as presented in Table 4. Similar to the main criteria, the sub-criteria must also be scored. Stage of technology (maturity) and performance are sub-criteria in technical performance with the biggest score, followed by flexibility, operability and reliability (Table 4). In the expenditure unit, CAPEX gets a bigger score than OPEX, because CAPEX is allocated for equipment multiplied by an installation factor [10]. Safety process and environmental effect are divided into two sub-criteria, which are hazardous material and emission that have the same score. Scoring of main criteria and sub-criteria is based on discussion with experts' judgment.

Table 4. Weightage for Sub-Criteria Technical Performance (2^{nd} Tier)

Criteria	weight (%)
Technical Performances	
Stage of Technology	25
Operability	15
Reliability	15
Performance	25
Flexibility	20
Expenditure Unit	
Capital Expenditure	60
Operating Expenditure	40
Safety Process and Environment Effect	
Hazardous Material	50
Emission	50

2.4.2. *Scoring of sub-sub-criteria*

Scoring of sub-sub-criteria for the main criteria of technical performance, expenditure unit and safety process & environmental effect is shown in Table 5, Table 6, and Table 7, respectively. Furthermore, Table 8 presents a summary of the characteristics of the CO_2 removal technologies. All parameters from each field, which are sub-sub-criteria, are matched with the table. The range score from each sub-sub-criteria is 1-5 which denotes: 1 = very poor, 2 = poor, 3 = moderate, 4 = good, 5 = very good

3. Results and discussion

According to the data in Table 2, we produce the AHP simulation for CO_2 removal selection technology. Each case contains a comparison of 3 CO_2 removal technologies including absorption (amines), adsorption (molecular sieves), and permeation (membranes). The samples chosen depend on the variation of feed gas flowrate and location.

By using the AHP simulation, we can compare the actual condition, selection based on conventional method and AHP simulations for fields A-F as presented in Table 9. Actual CO_2 removal technology has been taken from facility data which was chosen by company. Further, the conventional method evaluation was conducted using the chart in Fig. 1. The highest AHP score indicates the most suitable CO_2 removal technology. Selection of CO_2 removal technology by using the conventional method with insufficient criteria would give incorrect results. Hence, it is important to give additional criteria in the selection of CO_2 removal technology, including economic analysis and detailed technical performance from another alternative technology and environment side. AHP simulation is expected to provide better alternatives methodology for selecting CO_2 removal technology comparing with conventional one. It is possible because the AHP simulation have more criteria and give space for personal analyses (expert judgments) at each level of the hierarchy.

For the case in Field A, the CO_2 removal was implemented to "catch" CO_2 gases from the flare gas stream. Normally, in a gas-treating facility, flare gas is delivered to the flare stack to be burned but in this case, the flare gas stream is recycled and used pressure swing adsorption (PSA) to stripe some remaining methane from the flare gas stream and then sent as sales gas. It is generally accepted that for low quantities of raw gas in the feed stream, the adsorption technology (molecular sieves) is suitable. Adsorption-based CO_2 removal processes need low capital investment and energy compared to the conventional CO_2 removal (absorption using amine). However, the application of adsorption-based CO_2 removal technologies is still limited so far in the gas processing facilites with a feed rate of around 15 MMSCFD [11]. Whereas for processing large quantities of raw natural gas in the feed stream, no adsorption technology has been used due to the high investment in capital and operating costs.

Case B and C represents the offshore operation. The CO_2 removal applications in offshore operations are mostly

Table 5. Scoring for Sub-Sub-Criteria of Technical Performance

Technical Performance Sub Criteria / Score	1	2	3	4	5
Stage of Technology (Maturity/Population)	-	-	-	Commercial	Mature
Operability					
Temperature (F)	30	30 – 50	30 – 100	0 – 100	0 – 200
Pressure (psig)	$\leq$100	25 – 200	25 – 500	25 – 1000	$\geq$1000
Solvent	VOC	Solvent Not Stable	Stable	Very stable	No need solvent
Gas Flowrate (MMSCFD)		Not Suitable	Moderate	Suitable	Optimum
Reliability					
Energy Consumption	Very High	High	Moderate	Low	Very Low
Ease of Operation	Very High Complexity	High Complexity	Medium Complexity	Low Complexity	Very Low Complexity
Performance					
% CO_2	-	5-7	0.3 – 5	25 ppm – 5%	5 ppm – 5%
ppm H_2S	-	-	-	Possible	Yes
Contaminant	HC,BTEX, Solid Particles, Water, Glycol, Amines	HC, Water, Glycol, Amines	HC, Water	HC	
Turn Down Ratio	-	30% Above	30%	20%	Low
Flexibility					
Hydrocarbon Losses	Very High	High	Moderate	Low	Very Low
Type of product	-	-	GP*	GP* & LPG	GP*, LPG & LNG
Spare Part Availability	Very Rare	Rare	Moderate	Easy	Very Easy
Delivery Time	Very Long	Long	Moderate	Fast	Very Fast
On-Site Installation Time	Very Long	Long	Moderate	Fast	Very Fast
Transportation (due to location)	Very Hard	Hard	Moderate	Easy	Very Easy

*: Gas Pipe

Table 6. Scoring for Sub Sub-Criteria of Expenditure

Criteria / Score	1	2	3	4	5
CAPEX	Very High	High	Moderate	Low	Very Low
OPEX	Very High	High	Moderate	Low	Very Low

Table 7. Scoring for Sub Sub-Criteria of Safety Process & Environment Effect

Criteria / Score	1	2	3	4	5
Hazardous Chemical	Chemical with BTX	Solvent not stable	Solvent Stable	Solvent Very Stable	No Hazardous Material
Emission	VOC and H_2S	VOC	H_2S	Trace	No Emission

dominated by absorption methods. Although absorption is the most established technology, the application of the absorption process to offshore operations is particularly hindered by its excessive footprint requirement for bulk CO_2 removal. The capital expenditure is high because of the excessive footprint requirement for the absorption towers [17]. Therefore, the selection of suitable CO_2 removal technologies heavily depends on the footprint requirement, partial pressure of CO_2, and energy consumption [18]. In general for offshore operation, there is also concern about footprint and equipment dimension. However, the most important criteria were the capability to couple with the appropriate solvent for offshore application, long operating stability with minimal maintenance, resistance to H_2S, suspended particulate matter, fouling, water content, and heavy hydrocarbon [17]. Thus, the optimum CO_2 removal

Table 8. Summary of Characteristics of CO_2 Removal Technologies [11]

Process technology	Amines	Physical solvents	Hot potassium carbonate	Adsorption (PSA)	Membranes
Mechanism/Methods	Chemical absorption	Absorption in liquid	Chemical absorption	Adsorption on solid (Mol Sieves)	Permeation
Stage of Deployment of Technology	Mature	Mature	Mature	Commercial up to 2 MMscfd	Commercial
Commercial examples	ADIP-X, Econamine^{SM}, aMDEA	Selexol, purisol, rectisol	Benfield, catacarb, flexsorb, HP	Xebec PSA, Molecular	Separex^{TM}, Z-Top, Medal
CO_2 inlet concentration	Up to 70%	$P_{CO_2} > 3.5$ bar [19]	5–50%	Up to 40%	Up to 90%
CO_2 outlet concentration	2%, down to 50 ppmv	50 ppmv possible	≥1.5% (single-stage) ≥0.1% (two-stage) (30 ppmv with hybrid) [19]	50 ppmv possible	Down to 1–2%
Simultaneous H_2S removal	Yes (depends on the solvent)	Yes (most solvents)	With two-stage scheme	Possible	Possible
Typical flow rate (MMscfd)	Low to > 350	100 – 400	Low to > 260	CDPs: Up to 2	Low to > 350
Typical operating conditions					
Pressure (kPa)	Absorber: 5000–7000	Absorber: 6500–8000	Absorber: 5000–7000	1000–3500	2000–10,000
Temperature (°C)	Regenerator: 150 Absorber: 30–60	–73 to ambient	Regenerator: 150 100–116	25	< 60 (materials limit)
Contaminants	Oxygen, Solid particles, Heavy HC (liquid state), Organic acids	Solid particles, Heavy HC (liquid state)	Solid particles, Heavy HC (liquid state)	Heavy HC (liquid state), Glycols, Amines, Liquid water	Heavy HC, BTEX, Glycols, Amines, Solid Particles, Liquid water
Ease of Operation	High Complexity	High Complexity	Very High Complexity	Medium Complexity	Low Complexity
Hydrocarbon recovery/losses [10]	< 1% losses	Absorbs aromatics and heavy hydrocarbons	Very low	Co-adsorption of heavy hydrocarbons	1 stage: 8–15% 2 stages: < 2%
Turn Down Ratio (Gas Flow Rate)	30%	Approx 30%	30%	Low	20%
Footprint/layout considerations [10]	High	High	High	Medium	Low
Main equipment items [10]	Contactor Regenerator column Flash tank Lean/rich amine heat exchanger Lean amine cooler Solvent circulation Pumps	Contactor Multiple flash drums Heat exchangers CO_2 flash drum Recycle compressors Chiller Solvent circulation pumps	Contactor Regeneration system Gas/gas exchangers Lean solution cooler Circulation pumps	Adsorbent vessels Waste/regen gas Compressors Valve and piping skids	Membrane modules Pretreatment modules Compressors (2+ stage processes)

technology in Field B and C is the absorption method. In addition, field C has relatively low CO_2 (about 6%) which entered the gas treatment facility and it has high H_2S and wax as impurities. H_2S and wax can cause severe damage on membranes. Thus the application of membranes method for CO_2 removal in Field C is not suitable.

Absorption methods become the common solution for treating CO_2 from large quantities of raw gas in the feed stream, as indicated by field D. The amine process, as one of the absorption methods, is one of the most popular technologies used in natural gas processing facilities. Besides the amine process, the Benfield process using potassium carbonate (K_2CO_3) is also a mature technology for CO_2 removal. Potassium carbonate (K_2CO_3) has been studied for capturing CO_2 due to its low enthalpy requirements, low cost, low toxicity, high resistance to degradation and low solvent losses. However, it has a poor kinetic reaction in the absence of promoter which then results in a large absorption column [20]. Benfield process for CO_2 removal is no longer used in gas treating facilities in Indonesia. The main reason is mainly due to the required high temperature and pressure to operate [21]. However, when the gas-treating facility can produce sufficient quantity and quality of steam, Benfield process can be an option.

Despite of the popularity of amine process as a part of absorption technology, it occasionally suffers from foaming formation [4, 22]. Foaming is a major problem that arises in the acid gas absorption process using aqueous alkanolamine solutions. The foam may form at plant start-up and operation in both the absorber and regenerator. The foam is formed due to high gas velocities, sludge deposits on gas contactors, process contaminants entering the process with feed gas and makeup water, or generated in the process via alkanolamine degradation reactions [22]. For example, in field D, there are some diminutive mud carried from the production gas well to the amine process which triggered foaming. In this situation, the easiest solution is to set up the mud trap in the well stream flowline and if required, to inject antifoaming to ensure better contact between the solvent and the gas with rich gaseous CO_2.

The membrane process is still scarcely applied for CO_2 removal in Indonesia's natural gas processing. To date, only one field once used this method in South Sumatra Region which is now replaced by the amine process. The membrane process has advantages which make it attractive for industrial applications because of its ability to achieve higher separation efficiency, higher capital efficiency, and faster separation process coupled with the simplicity of operation in modern compact modules and high space economy [23]. In this case, the membrane process is re-

Table 8. Summary of Characteristics of CO_2 Removal Technologies [11] (continued)

Process technology	**Amines**	**Physical solvents**	**Hot potassium carbonate**	**Adsorption (PSA)**	**Membranes**
Energy requirements (main use)	High (solvent regeneration)	Medium (solvent circulation)	Medium (regeneration)	Low (purge gas/ recompression)	Low–medium (feed gas and interstage compression)
Comparative process costs [10]					
Capital	High	Medium	High	Medium	Medium
Operating	Medium	Low	Low	Low	1 stage: low 2+ stages: medium

Table 9. Comparison Actual CO_2 Removal VS Traditional Way vs AHP Simulation

Field	Location	Actual CO_2 Removal Technology	Selection using conventional method	AHP Simulation Score		
				Adsorption	Absorption	Membranes
A	Onshore	Adsorption (molecular sieves)	Membranes or Physical Solvent	**8.04**	7.63	7.43
B	Offshore	Absorption (Amines)	Membranes or Physical Solvent	7.09	**7.79**	7.23
C	Offshore	Absorption (Amines)	Amines, Physical Solvent, Potassium Carbonate	6.79	**7.81**	7.13
D	Onshore	Absorption (Amines)	Membranes or Physical Solvent	7.23	**7.89**	7.37
E	Onshore	Absorption (Amines)	Membranes or Physical Solvent	7.23	**7.89**	7.37
F	Onshore	Absorption (Amines)	Membranes or Physical Solvent	6.90	**8.01**	7.29

placed with the amine process because it is not suitable for gas production composition (gas production is still in wet condition), high rate hydrocarbon loss occuring during the process and low membranes performance.

The membrane process needs a high pressure, this is intended to create a greater driving force across the membrane. An increase in CO_2 in the feed stream will increase membrane area requirement as well as hydrocarbon/methane losses (more CO_2 must permeate, and so more hydrocarbons permeate) [24]. To reduce hydrocarbon/methane losses in the membrane process, an installation of multistage configuration can be used to reduce the hydrocarbon losses, however, the multistage configuration has higher investment costs than the single-stage configuration [25].

Membranes must be protected from the heavier hydrocarbons that are present in wet natural gas production streams. Exposure to these compounds will degrade the membrane performance and can cause permanent damage [24]. Low membrane performance will impact the frequency of maintenance and make a direct consequence on CAPEX and OPEX costs.

Fields D and E have the same score indicating that the proximity of quantities of raw gas in the feed stream to be treated, inlet and outlet CO_2 concentrations, location and type of product become the major criteria for selecting CO_2 removal technology. Referring to Table 8, the greater the quantity of raw gas in the feed stream has a trend to favor the amine process as corroborates from the evaluation of Field F.

4. Conclusion

Selection of CO_2 removal technology in Indonesia's gas processing facilities can be calculated using the proposed AHP method as presented in this work. The results from the AHP calculation gave good agreement with the actual AGRU or CO_2 removal technology in actual natural gas processing plants. Our work also showed that selection of CO_2 removal technology with AHP calculation gives different results if compared to the traditional approach. Selection of CO_2 removal technology with the traditional approach uses fewer criteria/factors than that with the AHP method in determining the goal. Eventually, the selection of CO_2 removal technology using the AHP approach gives the optimum result.

In the future, we can use these criteria for selecting CO_2 removal technology to be applied in plant development reviews for new gas fields. The scope for future research is to arrange a model for hybrid technology CO_2 removal. Future research can evaluate energy consumption, additional equipment, and chemicals/materials for maximizing process and long-term cost-benefit analysis.

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