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Natural Gas Dehydration Process Simulation and Inlet Conditions Case Studies Using Aspen HYSYS – TEG Dehydration

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Abstract: *To meet sales gas specifications and to optimise the economic value of the raw gas stream, it is vital to remove water from the gas stream. Water in pipelines can cause pipe plugging, corrosion, decrease in combustion efficiency, an increase in operating pressures, etc. The objectives of this paper were to verify the findings of the theory in literature by simulating a natural gas dehydration unit using TEG, performing various case studies of temperature and pressure variations as well as evaluating the costs involved. The Aspen HYSYS process simulator was used to simulate the natural gas dehydration unit in the simulation environment. The Aspen Process Economic Analyser was engaged to analyse the economic viability of the unit. Finally, Microsoft Excel was used to plot graphs and analyse the results of the simulation. Results showed that the unit was able to reduce the water content in the gas from 37.98 Ib/MMSCF to 2.493 Ib/MMSCF which falls below the maximum sales gas water content specification of 7 Ib/MMSCF. It was also seen that increasing the temperature of the feed gas, increases the gas` ability to hold more water, increasing the feed gas pressure, decreases the water holding capacity of the gas as stated in literature. It can be concluded that this unit operating at these operating conditions is optimal for industrial and commercial use.*

Keywords: *Case Studies, TEG Dehydration Unit, Inlet Conditions Variations, Process Simulation, Aspen HYSYS.*

1. Introduction

Natural gas is a major source of energy and it has become increasingly relevant as an alternative fossil energy. Before using natural gas by end users, it must be processed in many stages to reduce major problems; Water, other toxins, sand, and other impurities are removed from natural gas. Liquids can reduce the system's volumetric ability and interfere with the operation of pressure regulators and filters. Additionally, concentrated liquids accumulated in pipelines can cause an increase in operating pressures and the risk of equipment damage due to liquid carryover. As a result, it is important to prevent liquid water and hydrocarbons from condensing. The presence of moisture in natural gas can lead to issues like hydrate formation or freezing, which can lead to pipe plugging, corrosion, and a decrease in combustion efficiency others [1]

Dehydrating natural gas can be done in a variety of ways; Using a solvent to absorb water, e.g.: triethylene glycol (TEG), Cooling, Adsorption, Membrane separation, among others [1]. Glycol absorption method is used in most of the existing natural Gas treatment plants and facilities because of its higher boiling point than water and low vapour pressure. ethylene glycol, diethylene glycol, Triethylene glycol and tetraethylene glycol are the most commonly used glycols for dehydration applications. Among these, triethylene glycol (TEG) has gained collective acceptance as the most effective glycol type because it is more easily regenerated [7].

Gas absorption process using glycol is affected by several factors such as the number of trays in glycol contactor, glycol circulation rate through absorption column, temperature of the reboiler in the regenerator, amount of stripping gas used, operating pressure of the regenerator, carbon dioxide content in the feed gas [9].

2. Statement of Theory and Definitions

The energy industry has been in a state of transformation for the past decades. For instance, the image for associated petroleum gas, i.e., hydrocarbon gas found in crude oil reservoirs, has changed with time from a flared by-product to a valuable resource reaching more and more consumers worldwide. Lately, natural gas has arguably been highlighted due to its role in reducing CO_2 emissions in terms of decarbonisation, particularly compared to other energy sources such as coal. Furthermore, the low production cost per energy unit compared to other energy sources makes natural gas production an attractive research topic, particularly when associated with carbon capture and storage [4].

Natural gas is considered the cleanest and the most hydrogen-rich fuel among all fossil energy sources. Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is 'wet' [3].

3. Natural Gas Processing

Raw natural gas has a widely variable composition, depending on reservoir source, but is generally composed of methane (30%-90%), with other light hydrocarbons, such as ethane and propane, along with heavier hydrocarbons. In addition, the gas will contain water, carbon dioxide, hydrogen sulphide, helium and nitrogen at varying concentrations. It is necessary to process this raw natural gas to meet pipeline specifications and regulatory standards on calorific value [11].

3.1. Set Up of Gas Processing Plants

Chemical plants consist of different unit operations (nodes) such as reactors, separators, storage tanks, pumps, compressors, and so forth. The nodes are connected among themselves and with the environment by streams. Measurements of flows, temperatures, pressures, concentrations, etc. at different points of the nodes and streams are taken to control and evaluate process performance [10].

The raw gas is extracted from wells offshore and transported to the onshore gas plant through pipelines. The onshore plant's first phase is to segregate gas from the liquid using gravity in a slug catcher unit. Gas is treated through various process units to remove the acid gases, such as H_2S and CO_2, in order to produce what is known as sweet gas. Then the sweet gas will go through the dehydration unit to remove water in order to facilitate the separation of ethane, propane, and butane from methane and then through the mercury-removing unit, where injection of N_2 is an integral part of this process. Gas processing plants mainly need power and steam. Usually, most of the electricity is generated internally via gas and steam turbines [2].

4. Natural Gas dehydration Processes

Dehydration of natural gas is the removal of water that is mixed with natural gas in vapour form and is necessary to ensure smooth operation of gas transmission pipelines. Dehydration is required since water vapour present in the natural gas stream provides safety issues during the subsequent transportation process and is done through several processes. Among these is the use of ethylene glycol (glycol injection) systems as an absorption mechanism to remove water and other solids from the gas stream. Alternatively, adsorption dehydration may be used, utilizing dry-bed dehydrator towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction [8]Other processes include condensation, dehydration by expansion refrigeration, among others.

4.1. Dehydration by Liquid Absorption

Due to its relatively high volatility, the use of monoethylene glycol (MEG) is limited to injection into a wet gas stream for hydrate suppression rather than water dew point depression by contact with gas in an absorber tower. On the other hand, diethylene glycol (DEG), triethylene glycol (TEG) and tetraethylene glycol (TREG) possess suitable properties for dew point depression. The vast majority of the glycol dehydrators in service use TEG. DEG may be cheaper to buy in certain markets but when handling and other labour costs are accounted for there is little if any saving. Compared to TEG, DEG exhibits greater losses in carry-over, provides less dew point depression and regeneration to high concentrations is more difficult. TREG is more viscous and more expensive than the other processes.

It exhibits a lower vapour pressure which reduces absorber carry-over losses. It can be used in high temperature applications where dehydration of gases at temperatures in excess of 60 °C is required. Additionally, TREG is not as readily available as TEG. TEG is the most widely used and easily available desiccant for dehydration units [5].

4.2. Teg Dehydration

Triethylene Glycol (TEG) in particular is the most widely used glycol given its low evaporation loss rate and low thermal degradation rates in the regeneration system (Kong).The advantages of using TEG is ease of regeneration and operation, minimal losses of drying agent during operation, high affinity for water, chemical stability, high hygroscopicity and low vapour pressure at the contact temperature. Increased glycol viscosity may cause problems at lower contact temperature. Thus, heating of the natural gas may be desirable. [3]

5. Experiments And Theory

The natural gas dehydration process simulation for this study was done using the aspen ONE Engineering software suite version 11.0. The packages of the software used include Aspen HYSYS and the Aspen Process Economic Analyser. Aspen HYSYS is an easy-to-use, industry-standard simulation application that is used by process engineers, engineering firms and all involved in plant activities. Microsoft Excel was also used in analysing some of the results obtained from the Aspen HYSYS software and also for plotting graphs.

For this study, the natural gas dehydration unit was designed with a capacity of 10 MMSFCD and a pressure of 6200 kPa. However, this capacity was increased during the case studies to evaluate its efficiency. A steady-state simulation of the dehydration plant was performed for the objectives of this paper.

6. Fluid Package

A fluid package is an equation of state utilised by the software to determine gas stream parameters and conditions, and it is carefully chosen based on the process type as well as the pressure and other factors.

The Peng-Robinson model was chosen as the fluid package because it is ideal for calculating Vapour-Liquid Equilibrium (VLE) for hydrocarbon systems, as well as rigorously solving any single-, two-, or three-phase system with a high degree of efficiency and reliability under a wide range of temperature and pressure conditions.

The various equipment required for the natural gas dehydration process, such as an inlet separator, L/R heat exchangers, a valve, a contactor tower, a mixer, a pump and a distillation column, were chosen from a palette and connected by their respective material streams (flow lines).

It is important to define the feed stream's composition and conditions. The gas flow rate, temperature, and pressure are the needed input conditions.

It is also very necessary to define the various individual equipment's operating conditions. Without this information, HYSYS cannot calculate all the mass and energy equilibrium equations for the units and the units will be marked as unconverged.

The feed gas was initially passed through an inlet separator to separate the gas feed stream into liquid and vapour phases. The gas phase was then sent to the contactor tower where it was brought into contact with lean TEG in a counter current flow regime to remove water from the gas. The dry gas was passed through a heat exchanger to exchange its heat with the regenerated TEG then routed to the sales line whilst the rich TEG was sent to the regeneration section where the rich TEG is boiled closer to its decomposition temperature in the distillation column which contains a reboiler and a condenser to strip it of the absorbed water. Figure 1 shows the complete process flow diagram of the TEG plant.

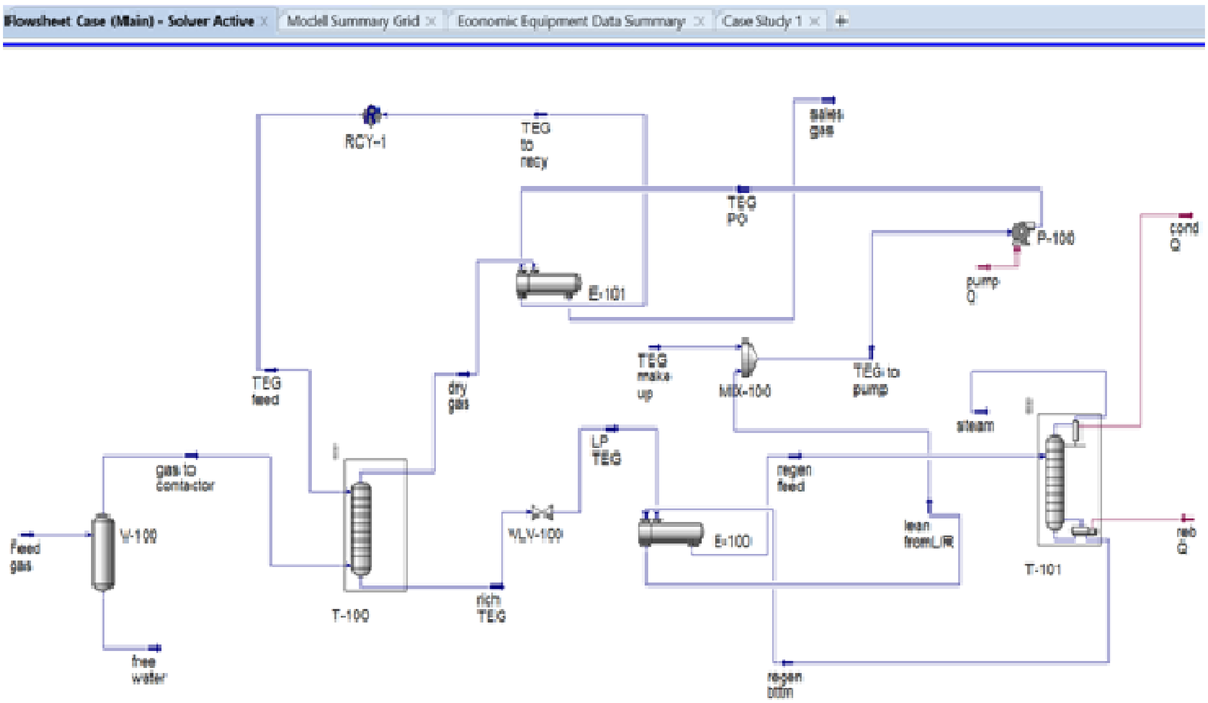

Fig1. *Complete TEG dehydration flow diagram*

7. CASE STUDIES

The Case Study tool lets you monitor the steady state response of key variables to changes in your process. For this paper, the nested type case studies were used to study the effects of three independent variables (feed temperature, feed pressure and feed flow rate) on one dependent variable (water content in the dry gas) separately.

8. COST ANALYSIS

Aspen Process Economic Analyser allows users to map, size, and estimate costs for equipment directly from process simulators. In order to get a near accurate cost analysis, the user needs to input current prices of some streams. These streams are the feed stream and the product stream. HYSYS automatically calculates other products using the prices input through iterations. It should be noted that the equipment and materials/utilities costs from the software are just estimates and real – time costs need to be input in order to get the most accurate cost predictions. For this study, the stream prices as at July, 2023 were as stated in Table 1. These values may vary with respect to time.

Table1. *Material Stream Prices*

Material Stream	Stream Price ($)
Feed gas (MMBTU)	2.68
TEG feed (kg)	1.50
Sales gas (MMBTU)	6.50

9. RESULTS AND DISCUSSION

The raw unprocessed natural gas stream obtained from the Jubilee Fields contained 0.08 mole% of water and at 30 ºC and 6200 kPa, this value translated to 643.015 mg/Sm3, an equivalent of 37.98 Ib/MMSCF as shown in figure 2. This is far above the pipeline specification of water in natural gas and therefore necessitated dehydration of the gas stream.

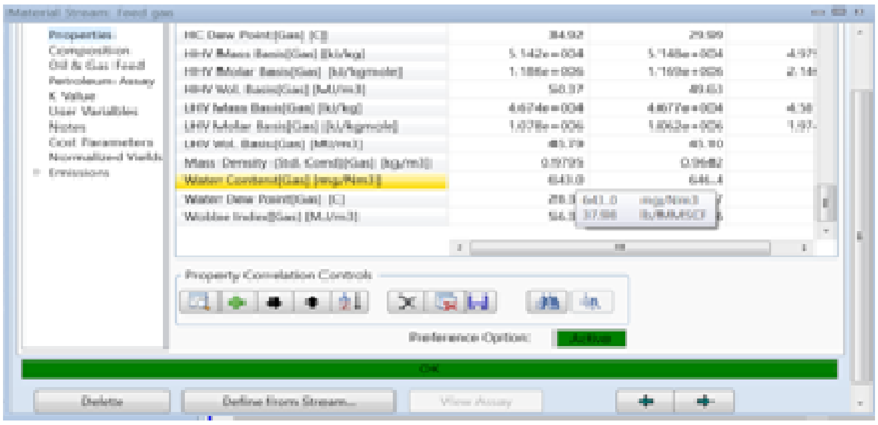

Fig2. *Feed Gas Material Stream*

10. Water Content Of Dry Gas

After passing through the contactor tower with a TEG temperature of 50 ºC and pressure of 6200 kPa, the water content of the gas reduced from 37.98 Ib/MMSCF to 2.493 Ib/MMSCF (42.207 mg/ Sm3) as shown in Figure 3. This is due to the fact that the TEG absorbed majority of the water vapour from the gas leaving an amount significantly below the pipeline water content specifications.

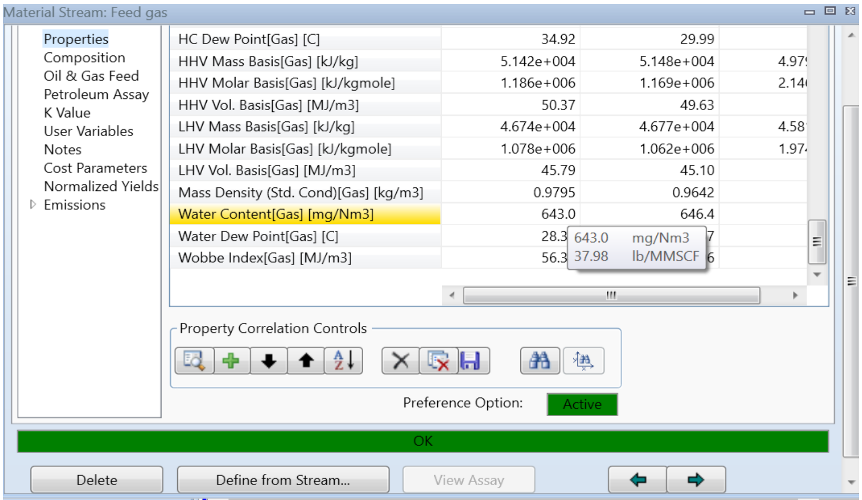

Fig3. *Dry Gas Material Stream*

11. Case Studies Results

The results from the various case studies are discussed in this section.

11.1. Temperature Case Study

The first case study conducted was a study of increasing the feed gas temperature and its effects on the water content of the dry gas. From Figure 4, it can be seen that as temperature increased, the water content of the gas also increased.

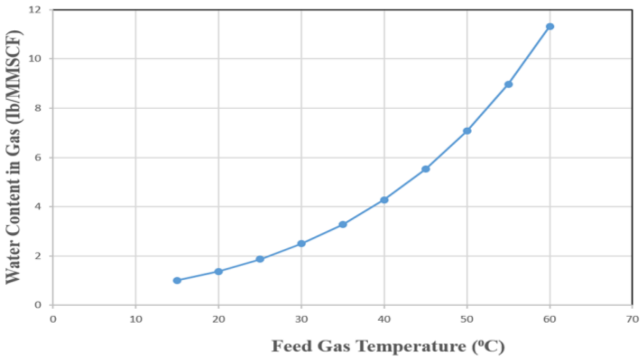

Fig4. *A Graph of Water Content in Gas Versus Feed Gas Temperature*

11.2. Interpretation

The maximum amount of water vapour that can be in the air depends on the air temperature. Warmer air can hold more water vapour within it than cooler air. But as the temperature goes down, the air can hold less vapour and some of it turns into liquid water through condensation. Because warmer air holds more moisture, its concentration of water vapour increases. Specifically, this happens because water vapour does not condense and precipitate out of the atmosphere as easily at higher temperatures. As the atmospheric temperature rises, more water is evaporated from ground storage like rivers, lakes, etc. and remains in the atmosphere.

A similar phenomenon applies to natural gas. Both natural gas and air are a mixture of other gases. Since free water is in the liquid phase, the liquid and gas phases separated by gravity. But as the temperature increased, more liquid water evaporated into water vapour. Both the water vapour and natural gas molecules now existed in the vapour phase together. The increased temperature caused the gas molecules to have more kinetic energy and they moved about creating space for more water vapour molecules to fill in the vapour space.

11.3. Pressure Case Study

The second case study conducted was a study of increasing the feed gas pressure and its effects on the water content of the dry gas. From Figure 5, it can be seen that as pressure increased, the water content of the gas decreased.

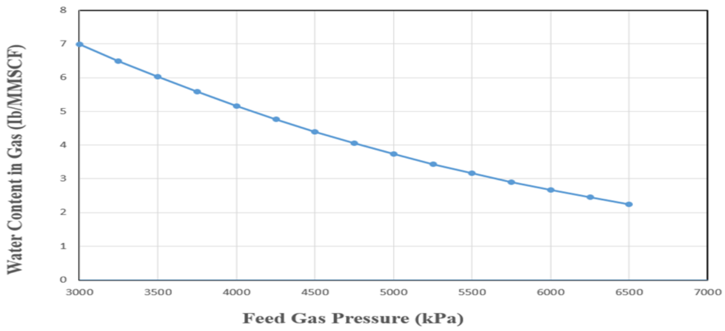

Fig5. *A Graph of Water Content in Gas Versus Feed Gas Pressure*

11.4. Interpretation

Air at lower pressures holds more water vapour than air at higher pressures (at the same temperature). Therefore, less water vapour condenses out of the air at the reduced pressures. As pressure increases, more water vapour condenses into liquid water and exists in the liquid phase rather than in the vapour phase. This is the opposite of increasing temperature.

Same applies to the gas. As the pressure was increased, the water vapour content of the gas condensed from the vapour phase to the liquid phase thus decreasing the water vapour content of the gas and increasing the free water content of the mixture as shown in Figure 6.

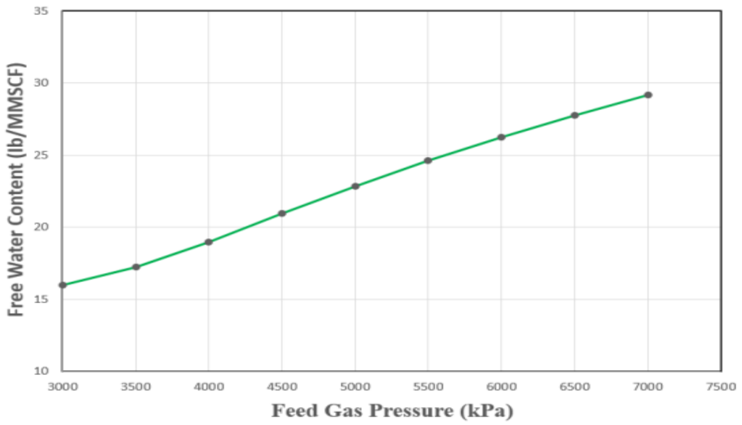

Fig6. *A Graph of Free Water Content in Gas Versus Feed Gas Pressure*

11.5. Flow Rate Case Study

Flowing the gas at 10 MMSCFD will not be the most economical or efficient. From figure 7, increasing the flowrate up to 170 MMSCFD maintained the water content at 6.22 Ib/MMSCF, which is still below 7 Ib/MMSCF therefore any flow rate between 10 MMSCFD and 170 MMSCFD will not affect the need to meet pipeline specifications.

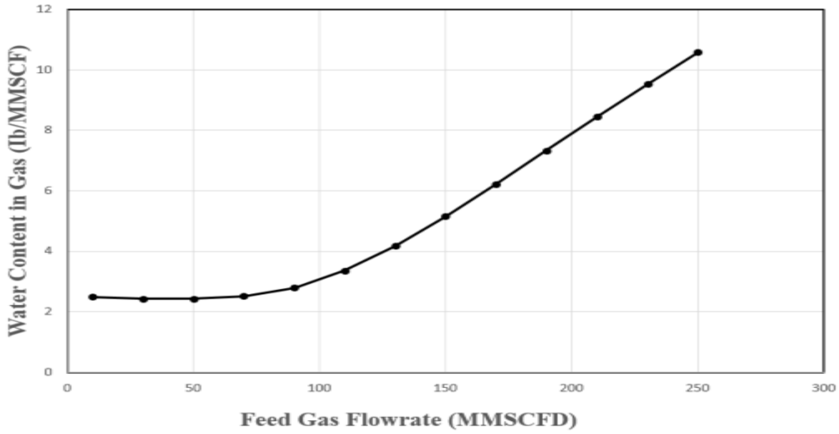

Fig7. *A Graph of Water Content in Gas Versus Feed Gas Flowrate*

12. Cost Analysis Results

Table 2 shows the individual costs to be incurred. Table 2 was generated by the Aspen Economic Analyser after the user input the material stream prices. From the table, it can be seen that it would take approximately 11 years out of the 20 years to recoup the initial capital investment of USD 7,509,220 and become minimally profitable. Note that these costs generated will not be the exact costs to be encountered in real time. These estimates are available to guide the engineer on how much the unit and its ancillaries might cost and not the exact values.

Table2. *Summary of Cost Analysis*

Cost	Value
Total Capital Cost [USD]	7,509,220
Total Operating Cost [USD/Year]	1,852,010
Total Raw Materials Cost [USD/Year]	416,347
Total Product Sales [USD/Year]	6,007,190
Total Utilities Cost [USD/Year]	109,806
Desired Rate of Return [Percent/'Year]	20
Pay out Period [Year]	11.1108
Equipment Cost [USD]	346,600
Total Installed Cost [USD]	1,205,400

13. Conclusion

This paper consists of the process simulation and cost estimates of natural gas dehydration using triethylene glycol and feed gas temperature, pressure and flowrate case studies. It can be established from the analysis of results obtained that:

1. he TEG dehydration unit was successfully simulated and able to reduce the water content in the gas from 37.98 Ib/MMSCF to 2.493 Ib/MMSCF which falls below the maximum sales gas water content specification of 7 Ib/MMSCF;
2. gradual increase in the temperature of the feed gas, increased the gas` ability to hold more water as seen in Figure 4, indicating that at higher temperatures, natural retains more liquids than necessary;

3. he higher the feed gas pressure, the lower the water holding capacity of the gas as shown in Figure 5 as most of the water condensed and separated through gravity from the gas in the inlet separator before entering the contactor tower;

4. n increase in feed gas flowrate increases the water content of the gas as a higher flowrate means reduced time of contact between the gas and TEG for absorption to take place as demonstrated in Figure 7; and

5. he economic analysis was just an estimate of the actual costs and an engineering firm that specializes in equipment sizing, mapping and evaluation is required for the most accurate and cost effective analysis.

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