



Natural Gas Processing

Related terms:

Crude Oil, Natural Gas, Hydrogen, Carbon Dioxide, Liquefied Natural Gas, Processing Plant, Propane, Raw Natural Gas

Introduction to Natural Gas Processing Plants

William A. Poe, Saeid Mokhatab, in Modeling, Control, and Optimization of Natural Gas Processing Plants, 2017

1.5.2 Process Control

Processing natural gas to profitably produce end products requires precision and is potentially hazardous. Small changes in a process can have a large impact on the end result. Conditions such as pressure, temperature, flow, composition, and many other factors must be controlled carefully and consistently within specified limits to ensure quality and safety. A well-designed, maintained, and leveraged control system will reduce start-up time, maintain maximum operating profit, avoid forced shutdowns, keep operating and maintenance costs as low as possible, assist in the management of environmental compliance, and support plant safety and security needs without adversely affecting construction costs.

An overview of the main control functionalities in the gas processing plant and their applications are described in subsequent chapters.

Read full chapter

URL: <https://www.sciencedirect.com/science/article/pii/B9780128029619000012>

Gas Sweetening

Maurice I. Stewart Jr. PhD, PE, in Surface Production Operations (Third Edition), Volume 2, 2014

9.1.2 Natural Gas Processing

Processing consists of separating all of the various hydrocarbons and impurities from the raw natural gas to produce what is termed “pipeline quality” dry natural gas. Pipeline companies impose restrictions on the makeup of natural gas allowed into the pipeline. Pipeline companies require the raw natural gas to be purified by removing “waste products” and associated hydrocarbons such as ethane, propane, butane, *i*-butane, and pentane plus (natural gasoline).

Associated hydrocarbons termed “natural gas liquids” (NGLs) can be a valuable byproduct of natural gas processing. They can be sold separately and have a variety of different uses, such as enhancing oil recovery in oil wells, providing raw materials for oil refineries and/or petrochemical plants, and as sources of energy.

Some of the needed processing can be accomplished at or near the wellhead (field processing). Complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. Extracted natural gas is transported to processing plants through a network of gathering pipelines. A complex gathering system may consist of thousands of miles of pipeline, interconnecting the processing plant to more than 100 wells.

In addition to the processing done at the wellhead and centralized processing plants, some final processing is also done at “extraction plants.” These plants are located on major pipeline systems and remove small quantities of NGLs that may still exist in pipeline-quality gas.

Natural gas processing to meet pipeline-quality gas standards involves the following four main steps to remove the various impurities:

- Oil and condensate removal
- Water removal
- Separation of NGLs
- Sulfur and carbon dioxide removal

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. Scrubbers remove sand and other large-particle impurities. Heaters ensure that the temperature of the gas does not drop below the hydrate formation temperature.

When the gas temperature drops there is a tendency for “hydrates” to form. Hydrates are solid or semi-solid compounds, resembling ice-like crystals. Should these hydrates accumulate, they can impede passage of natural gas through valves and gathering systems, plug process instrumentation, and reduce the capacity of processing vessels. To reduce the occurrence of hydrates, the following equipment may be used:

- Indirect-fired heater
- Hydrate inhibitors
- Dehydration
- Low-temperature units

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780123822079000093>

Process Control Fundamentals

Saeid Mokhatab, William A. Poe, in [Handbook of Natural Gas Transmission and Processing](#), 2012

14.1 Introduction

Processing natural gas to profitably produce end products requires precision and is potentially hazardous. Small changes in a process can have a large impact on the end result. Conditions such as pressure, temperature, flow, composition, and many other factors must be controlled carefully and consistently within specified limits to ensure quality and safety. Process control enables the safe and reliable production of natural gas and its derivatives while reducing manufacturing costs such as raw materials and energy.

This chapter introduces readers to a better understanding of the fundamental concepts in dynamics and process control, which include the ability to select a process control configuration for specific applications, decide on suitable instruments for process monitoring, develop input-output relationships,

understand the dynamic open-loop and closed-loop characteristics, and design and tune [feedback controllers](#).

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780123869142000145>

Environmental Aspects of the Natural Gas Supply Chain

Saeid Mokhatab, William A. Poe, in [Handbook of Natural Gas Transmission and Processing](#), 2012

19.10.6 Hazardous Materials

Natural gas processing facilities use and produce significant amounts of hazardous materials, including raw materials, intermediate/final products, and byproducts. The handling, storage, and transportation of these materials should be managed properly to avoid or minimize the environmental impacts from these hazardous materials. Hazardous waste should be determined according to the characteristics and source of the waste materials and applicable regulatory classification. In [gas-to-liquids](#) (GTL) facilities, hazardous wastes may include bio-sludge; spent catalysts; spent oil, solvents, and filters (e.g., activated carbon filters and oily sludge from oil–water separators); used containers and oily rags; mineral spirits; used sweetening; spent amines for CO₂ removal; and laboratory wastes.

Spent catalysts from GTL production are generated from scheduled replacements in natural gas [desulphurization](#) reactors, reforming reactors and furnaces, [Fischer–Tropsch synthesis reactors](#), and reactors for mild hydrocracking. Spent catalysts may contain zinc, nickel, iron, cobalt, platinum, [palladium](#), and copper, depending on the particular process. Recommended waste management strategies for spent catalysts include the following: (1) proper on-site management, including submerging pyrophoric spent catalysts in water during temporary storage and transport until they can reach the final point of treatment to avoid uncontrolled [exothermic reactions](#); (2) return to the manufacturer for regeneration; and (3) off-site management by specialized companies that can recover the heavy or precious metals through recovery and recycling processes whenever possible or that can otherwise manage spent catalysts or their nonrecoverable materials. Catalysts that contain platinum or palladium should be sent to a noble metal recovery facility.

Heavy ends from the purification section of the [methanol synthesis](#) unit are normally burned in a steam boiler by means of a dedicated burner.

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780123869142000194>

Computer Aided Property Estimation for Process and Product Design

Eric Hendriks, Henk Meijer, in [Computer Aided Chemical Engineering](#), 2004

11.3.1 Equilibrium Conditions

In natural gas production and processing, one wants to answer questions such as: do hydrates form at the given composition and conditions? At which conditions do hydrates form for the first time? Under adiabatic depressurization, will the hydrate disappear or not? How much water must be removed from the mixture to avoid hydrates? How much inhibitor is required to avoid hydrate? These questions may be answered by applying thermodynamics, by performing phase equilibrium calculations, for which the [Gibbs free energy](#) of the system is required

$$G = \sum_i \sum_{\alpha} \beta^{\alpha} x_i^{\alpha} \mu_i^{\alpha} (p, T, \mathbf{x}^{\alpha}) \quad (4)$$

Here β^{α} are the phase mole fractions and μ_i^{α} is the chemical potential of species i in phase α , which is a function of pressure, temperature and composition. For rigorous multiphase calculations, a model is required for all phases. Stability of a mixture at a given composition implies that the Gibbs energy must be at an absolute minimum, under the following constraints

- a) Phase fractions should be between zero and unity

$$0 \leq \beta^{\alpha} \leq 1 \quad (5)$$

- b) The condition of material balance, *i.e.* component amounts in the phases should add up to reproduce the overall amount z_i of the component i present

$$\sum_{\alpha} \beta^{\alpha} x_i^{\alpha} = z_i \quad (6)$$

- c) Normalization of phase fractions

$$\sum_{\alpha} \beta^{\alpha} = 1 \quad (7)$$

At the minimum, the familiar phase equilibrium equations hold

$$\mu_i^{\alpha} = \mu_i^{\alpha'} \quad (8)$$

for each pair of phases present. Note that the number of phases is not a priori given. It cannot, however, exceed the value $2 + N_c$, where N_c is the number of components (Gibbs phase rule).

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/S1570794604800130>

Assessment of corrosion in amine-based post-combustion capture of carbon dioxide systems

P. Pearson, A. Cousins, in [Absorption-Based Post-combustion Capture of Carbon Dioxide](#), 2016

18.5.8 Corrosion inhibitors

In [natural gas processing](#) plants, corrosion is commonly minimized by adding inhibitors. Inhibition allows the use of lower-cost carbon steels in construction, thereby reducing the cost of the plant. As mentioned in Section 18.3.3, care needs to be taken when selecting the correct [corrosion inhibitor](#), because incorrect choices can increase amine degradation and losses. Toxic heavy metals are traditionally used, but one study has shown equally effective inhibition using less toxic carboxylic acid-based inhibitors at 80°C, although the efficiency was halved at 40°C (Veawab et al., 2001).

Soosaiprakasam and Veawab (2009) found that corrosion inhibitor efficiency depends on several factors, such as inhibitor concentration (eg, at 500 ppm CuCO_3 , the efficiency was poorer than at 250 ppm). Inhibitor efficiency was >95% in tests with high [solution velocity](#), but varied depending on the type of HSS: 80% for bicine, but <50% for formate, oxalate, and [thiosulfate](#). These results indicate that inhibitor efficiency can be highly dependent on process conditions, and that one corrosion inhibitor may not solve all problems.

At the Castor pilot plant, in situ [corrosion coupons](#) were installed during two campaigns: one with and one without a corrosion inhibitor. The [corrosion rate](#) at

the stripper outlet was halved by the addition of the inhibitor, but the temperature in that campaign was also lower, by $\sim 10^{\circ}\text{C}$. The corrosion rates at other locations were generally low in both campaigns. However, when any differences were observed, the corrosion rate was lower in the campaign without the inhibitor (Kittel et al., 2009). These experimental results highlight the importance of carefully selecting both the type and concentration of inhibitor.

Idem et al. compared the amine degradation rates from two pilot plants. In the first pilot plant, which used a corrosion inhibitor and treated flue gas containing SO_2 from a coal-fired power plant, the amine degradation was significant. The second pilot plant, which treated flue gas from the combustion of natural gas (no SO_2) and did not use a corrosion inhibitor in the absorption liquid, had an insignificant rate of amine degradation. The authors suggested that the difference in degradation was due either to the presence of SO_2 or to the corrosion inhibitor acting as a catalyst and facilitating amine degradation (Idem et al., 2006). Unfortunately, the data were insufficient to determine which factor had the greatest impact.

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780081005149000184>

Remedial process optimization and sustainability benefits

Jim Leu, Deyi Hou, in Sustainable Remediation of Contaminated Soil and Groundwater, 2020

4.5 Petroleum hydrocarbons site, California, USA

The natural gas processing site is impacted with TPH and BTEX in both soil and groundwater. Maximum impact was detected in the smear zone. An SVE and an AS system were implemented to remove TPH in soil and groundwater, respectively (Fig. 11.6). After gasoline-range organics (GRO) and light-end diesel-range organics (DRO) were removed, the AS/SVE system reached its technology limit using volatilization mechanism. To expedite the removal of the remaining heavy-end DRO, the AS/SVE system was optimized to operate as a biosparging/bioventing system focusing on biodegradation mechanisms. Following system optimization, the site is nearing no-further-action status (Leu et al., 2015).



Figure 11.6. Soil vapor extraction and air sparging systems.

An SVE system was implemented to remove COCs in the vadose zone when the groundwater elevation declined, resulting in an exposed smear zone. The SVE system consisted of six SVE wells and three 2000-pound GAC vessels for vapor treatment. Two years later, an AS system was implemented to remove COCs in groundwater. The AS system consisted of two AS wells and four groundwater monitoring wells. Field observation indicated that the cumulative COC removed by SVE reached an asymptotic level. An early breakthrough of the GAC vessels was diagnosed as low-carbon-affinity polar compounds generated from DRO degradation. GRO was not detected in groundwater monitoring wells. These observations indicate that biodegradation mechanisms gradually dominated the COC removal. The AS/SVE system was optimized to a more sustainable biosparging/bioventing system by optimizing AS flow rate to sustain air required for biosparging in the saturated zone and shutting down low-concentration SVE wells to allow air migration through the vadose zone for bioventing. Optimization to biosparging/bioventing system from existing AS/SVE system reduces a significant SVE O&M cost, lowers energy requirements, and is more cost-effective in removing heavy parts of DRO through biodegradation mechanisms. After operating the SVE system for 2.5 years, the average VOC concentrations were reduced by approximately 75% in the vadose zone. After 9 months of AS operation, the groundwater DRO concentrations decreased by approximately 70%.

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780128179826000112>

Gas Dehydration and Purification by Adsorption

Arthur L. Kohl, Richard B. Nielsen, in Gas Purification (Fifth Edition), 1997

Removal of Sulfur Compounds

In natural-gas processing, the mercaptans are generally the most strongly adsorbed impurities (other than water), followed by H₂S with CO₂ being the most weakly adsorbed compound in this series. However, all mercaptans are not adsorbable by type 4A or 5A sieves because pore size limitations prevent adsorption of any but the lightest members of the family. As a consequence, 13X is the preferred adsorbent for complete sulfur removal from natural-gas streams. Existing commercial sulfur removal units treat natural-gas streams at flow rates ranging from 2 to over 200 MMscfd. Data on a large plant are given in Table 12-19. The presence of a trace of glycol, glycol degradation products, and absorber oil in the feed gas is noted as these heavy molecules affect both capacity (by coadsorption) and bed life (due to coke formation). It is claimed that a properly designed molecular sieve, sulfur removal system will perform for 3 to 5 years before new adsorbent is required (Conviser, 1965).

Table 12-19. Design and Operating Data for Large Mercaptan Removal Plant

Natural gas feed rate, MMscf/day	200
Feed gas pressure, psig	750
Adsorber description	(two horizontal vessels)
Diameter, ft	6

Length, ft	36
Bed depth, ft	3
Adsorbent charge, (per vessel) lb	25,000 (Type 13X)
Inlet gas composition	
Mercaptan and heavy sulfur, grains/100 scf as H ₂ S	2
Water, lb/Mscf	<7
Glycols, glycol degradation products, and absorber oil	trace
H ₂ S and CO ₂	nil
C ₄ hydrocarbons, % vol.	0.03
C ₁ , C ₂ , C ₃ , and N ₂	balance
Product gas, total sulfur, grains/100 scf as H ₂ S	<0.06

Operating Cycle:

Step	Flow Direction	Time
1. Purify	Down	12 hours
2. Hot purge (600°F)	Up	8 hours
3. Cool purge	Down	4 hours

Conviser, 1965

Copyright © 1965

Molecular sieves are very effective for H₂S removal and can produce gas containing extremely low levels of this impurity. Since H₂S is adsorbed more strongly than CO₂, the molecular sieves also offer the capability for selectively removing H₂S from gas streams that contain both impurities. However, the process has not gained general acceptance because of the problem of disposing of the sulfur-rich regeneration gas. The problem has been bypassed in one process scheme that is applicable to cases where it is desired to leave part of the CO₂ in the gas stream while removing essentially all of the H₂S and water. This flow arrangement is shown diagrammatically in Figure 12-31 for a typical case. The gas feed to the dry bed and liquid absorption units is ratioed in such a manner that the final mixed product meets pipeline CO₂ specifications. The increased gas volume that results from leaving 3% CO₂ in the product gas provides a credit for gas sold on a volume basis. Use of the dry-bed adsorption process on a portion of the gas has the further advantage of permitting the liquid absorber system to operate closer to maximum capacity, as a product gas which is slightly off specification with regard to H₂S, and water can be tolerated for dilution with the very pure adsorber product.

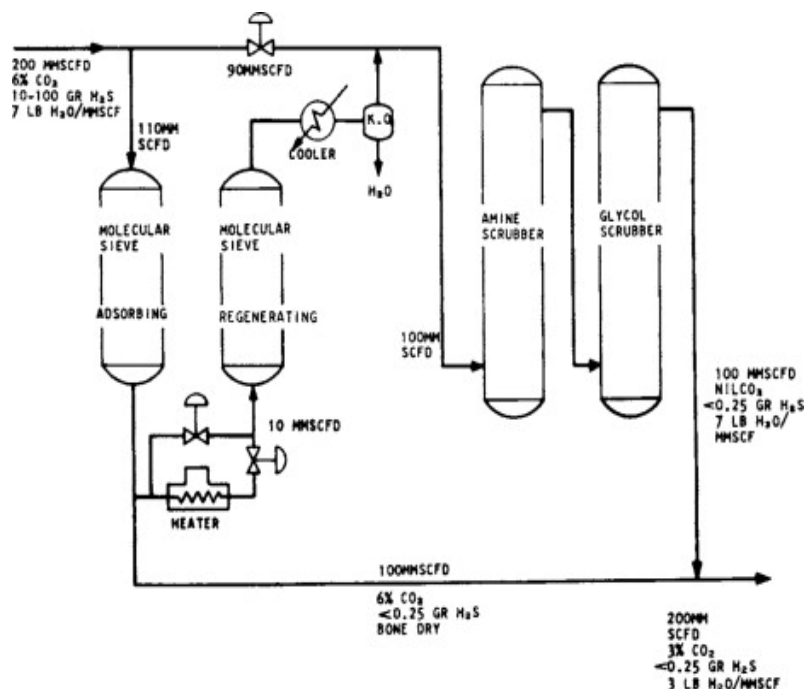


Figure 12-31. Combination molecular sieve-liquid absorbent process scheme for purifying carbon dioxide-rich natural gas.

Data of Thomas and Clark (1967) Copyright © 1967

Molecular sieves have also found application for desulfurization of natural-gas feed to ammonia plants. Removal of all types of sulfur compounds ahead of these plants is desirable because sulfur acts as a temporary poison to steam-hydrocarbon reforming catalysts and a permanent poison to expensive low-temperature shift conversion catalysts. An installation employing a standard dual bed adsorption system has been described by Lee and Collins (1968). The authors also describe comparative tests of a molecular sieve and a commercial grade of impregnated activated carbon in a dual-bed mobile pilot unit. The test results indicated that the molecular sieve could treat 2 to 4 times as much gas per unit volume of adsorbent as the carbon. The commercial plant consistently provided gas to the primary reformer containing less than 0.3 ppm (vol) peak total sulfur from a feed gas averaging about 0.6 ppm H_2S , 0.7 ppm mercaptans, 1.6 ppm sulfides, and 1.2 ppm residual sulfides. In this application, the high-sulfur purge gas can be fed into the plant fuel system so that the sulfur is finally vented to the atmosphere as dilute sulfur dioxide. Although this disposal method is preferable to venting the original sulfur compounds, it is not broadly acceptable and constitutes a significant drawback to the process.

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780884152200500124>

Energy Management

Humera Rafique, in *Comprehensive Energy Systems*, 2018

5.15.2.4.5 Examples of programmable logic controller programming languages

Example 4

A **natural gas processing** plant implements an intricate industrial process to get “pipeline quality dry natural gas” by separating several impurities and non-

methanic hydrocarbons and liquids from the raw natural gas. The other products, for example, natural gas liquids (gasoline and liquid petroleum gas) and some other chemicals like sulphur can also be extracted by the same plant [60]. For this processing, there are standards set by pipeline transmission and distribution companies, and follow a few main principle points including [61]:

1. Particular caloric value (BTU/ft³)
2. Hydrocarbon view point temperature (below which liquid slugs in pipelines can damage the pipeline)
3. Free of water vapors, erosive and corrosive particles

And many more.

A natural gas proceeding plant subunit is responsible to monitor the hydrocarbon view point temperature, and a backup unit is responsible to countercheck the pipeline pressure. A green visual indicator will light up if the gas pump is running and reading from pressure sensor shows the satisfactory level of the pipeline pressure. The system subunit has two inputs (pump and pressure), and if one of the inputs to the monitoring system (PLC) fails the indicator will switch OFF and a diagnostic test will start to troubleshoot the problem.

Fig. 59 shows the LD, and logic circuit diagrams to implement the above logic. Fig. 60 shows the functional block diagram implementation for the same example (Fig. 61).

Example 5

This example demonstrates the IL program code for the above example [51]:

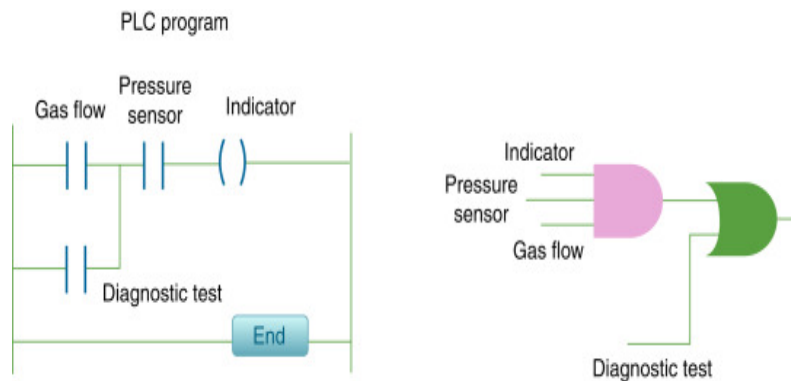


Fig. 59. Pipeline pressure and flow monitoring unit example, programmable logic controller (PLC) programming and logic circuit.

Reproduced from Bolton W. Programmable logic controllers. 5th ed. Dunfermline: Elsevier Ltd.; 2009.

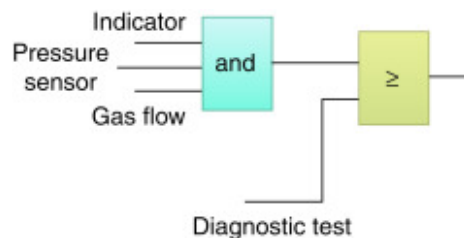


Fig. 60. Function block program for the pipeline pressure and flow monitoring unit example.

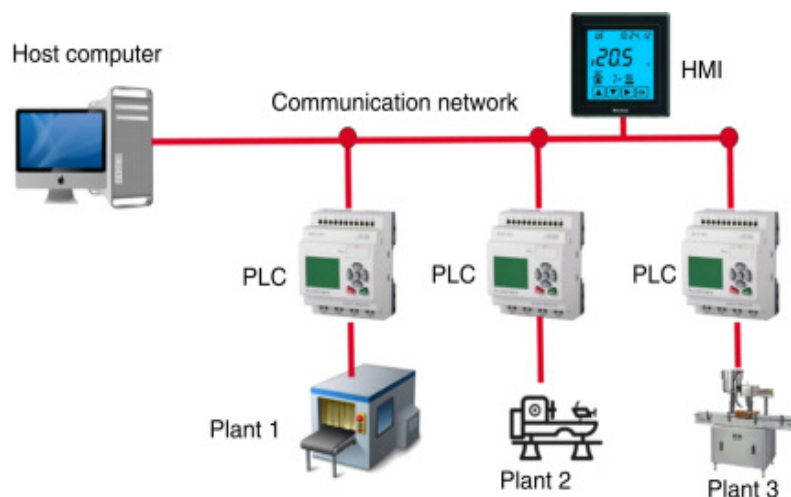


Fig. 61. Programmable logic controller (PLC) in distributed control system (DCS). HMI, human machine interface.

Reproduced from Icon images. Available from: <http://www.keyword-suggestions.com/>, incolors.club, ebay.com, radhemachines.com. and Petruzella FD. Programmable logic controllers. 4th ed. New York, NY: McGraw-Hill; 2011.

A 10.0

A 10.1

A 10.2

O

= Q2.0

[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9780128095973005319>

Transportation, Processing, and Refining Operations

M. Ibrahim Khan, M.R. Islam, in [The Petroleum Engineering Handbook: Sustainable Operations](#), 2007

8.3.5.2 Amines

Amines are used in **natural gas processing** to remove H_2S and CO_2 . **Monoethanolamine**, diethanolamine, and triethanolamine are alkanolamine compounds. These are synthetic chemicals, the toxicity of which has been discussed above. Monoethanolamine is found in hemp oil that is extracted from the seeds of hemp (*Cannabis sativa*) plant. One hundred grams of hemp oil contain 0.55 mg of monoethanolamine. Moreover, an experimental study showed that olive oil and waste vegetable oil can absorb **sulfur dioxide**. Figure 8-24 indicates the decrease in pH of de-ionized water with time. This could be a good model to remove sulfur compounds from natural gas streams.

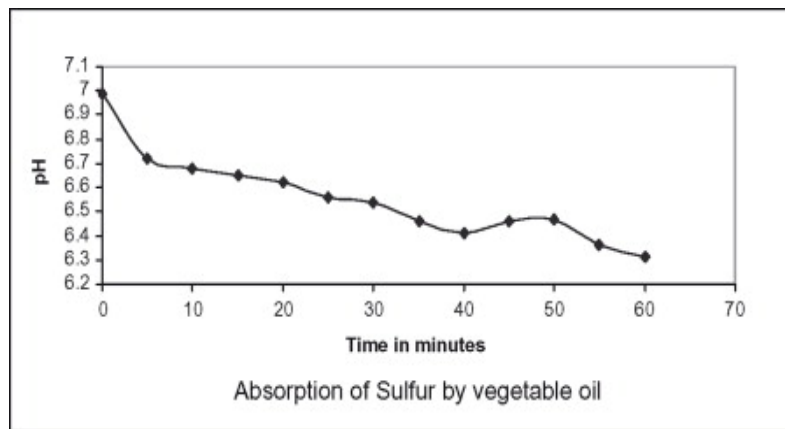


Figure 8-24. Decrease of pH with time, due to sulfur absorption in de-ionized water.

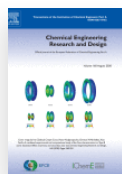
[Read full chapter](#)

URL: <https://www.sciencedirect.com/science/article/pii/B9781933762128500155>

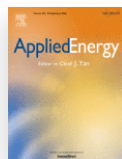
Recommended publications



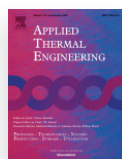
International Journal of Greenhouse Gas Control
Journal



Chemical Engineering Research and Design
Journal



Applied Energy
Journal



Applied Thermal Engineering
Journal



Copyright © 2021 Elsevier B.V. or its licensors or contributors.
ScienceDirect® is a registered trademark of Elsevier B.V.

