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(Refer to Appendix A)

Abstract

The goal of the oil producing companies are to extract hydrocarbon from the reservoir and make it available to customers. From an environmental perspective, it should be achieved with zero accidents, no harm to people, no impact on animal life cycle and no damage to the environment. The oil industry and environmental authorities are working closely together to achieve this by seeking practices and technologies that can support them reducing emissions, discharges and to be energy efficient.

Oil production from a reservoir general happens in three phases such as primary recovery, secondary recovery and tertiary recovery. In primary oil recovery, oil is produced to the surface by natural reservoir pressure. The oil production rate reduces when the reservoir pressure gradually decreases.

Secondary recovery (Increased Oil Recovery) usually involves large scale operational techniques such as Water Injection (WI) or Water and Gas (WAG) Injection. Injection of large volumes are introduced as an alternative to make up the pressure decline in an oil reservoir. Water and gas is injected into the reservoir to pressurise and sweep as much oil as possible to the production wells.

Tertiary oil recovery (Enhanced Oil Recovery) generally happens towards the end of field lifetime and is more field specific. Techniques can include Polymer Injection, CO₂ injection, Low salinity water injection, etc. and are not usually designed for at platform design stage. It should be mentioned that tertiary recovery method is not as a scope of this paper although some tertiary methods are dependent on good secondary recovery practices.

Secondary recovery / IOR / Waterflooding

For offshore oil production, injection of treated seawater into the reservoir from topside became one of the most common techniques for increased oil (secondary) recovery. For example, in the North Sea, injection of seawater from topside is already normally included for in the design phase of most oilfield production facilities. However, such platform based injection equipment can be expensive, heavy and occupy much space. It can also contain several technical and environmental problems relating to climate pollution (e.g. emission of CO₂ and NO_x) and discharge of injection chemicals into the sea and their impacts on human and animal's natural life cycle.

Secondary recovery uses large amounts of power and various kinds of injection chemicals, which creates concerns for both the environmental authorities and the oil industry that must be dealt with. They are therefore eagerly seeking development and implementation of new technologies that can assist them to improve or replace traditional methods.

The objective of this master thesis is to investigate the development of a new subsea water intake and treatment technology (SWIT) developed by Norwegian Company, Seabox AS. It is perceived that implementation of SWIT will enable some environmental benefits when compared to the already existing seawater injection technology used on topside facilities.

Following 10 years of development and testing, Seabox has developed and provided state of the art technology for treating seawater directly on the seabed. This is achieved by extracting water from the surrounding seabed area. On the seabed there are already inherent treatment advantages such as more space, lower stable temperatures, a lower

degree of bacteria concentration and seawater intake is well away from the variety of platform discharges.

The tests results gained for SWIT have shown that this method of treating seawater can be made to produce high quality treated water in the areas that are important for IOR with minimised environmental impacts.

In this thesis, SWIT treatment system is compared with a typical topside water injection treatment system, focusing on areas where SWIT could show environmental impact benefits. One such area is chemical usage where SWIT generates its own chemicals from electrolysis and therefore has reduced / no liquid chemical usage. This has effect on reduction in usage and potential discharge of injection chemicals (e.g. biocide, hypochlorite, oxygen scavenger, filter aids, scale inhibitors, corrosion inhibitors) that will normally be applied on a topside WI treatment system. Another positive environmental effect of SWIT is that it does not need to draw water up to a production platform and push it through a large treatment plant. Therefore, significantly less power is required to get the same amount of water to the same place in the reservoir – thus incurring less emission of harmful gases such as CO₂ and NO_x to the air.

In order to gain a detailed understanding about water flooding in general, this thesis has described:-

- The theory of waterflooding and the relevance of seawater quality to common reservoir issues
- A typical topside seawater injection system
- The operational details of the SWIT system
- The role of HSE importance in oil companies' framework
- A comparison between the SWIT technology and a topside treatment system

Comparison factors have been based on environmental aspects such as energy consumption (Power) and chemical usage, materials and offshore manning.

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This master thesis is performed in order to fulfil the requirements of Master Science degree in the Offshore Environmental Technology Master's degree program at University of Stavanger. The Thesis work was carried out at Seabox AS, Stavanger, Norway.

First of all I would like to use this opportunity to thank my supervisor, Mr. David Pinchin for giving me the chance of performing this thesis under his supervision. Without his efforts, this thesis would not have been possible. His creativity formulating thesis goals and always being available to sit down and give a true professional opinion is highly valued and appreciated.

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Deepest gratitude is also to my husband for his understanding, untiring effort in encouraging, supporting and loving. I could not finish my educations successful without his support in Norway.

Last but not least, I wishes to express my love and gratitude to my beloved father and mother for their unconditional and endless love. This master thesis is dedicated to them.

Anita Aghabalaei

20 June 2013

Abbreviations

BBD	Barrels Per Day
bbld	Billions barrels per day
CAPEX	Capital Expenditure
CFD	Computational Fluid Dynamics
CHARM	Chemical Hazard Assessment and Risk Management
DA	Deaerator
DP	Dynamic Positioning
DREAM	Dose Related Risk and Effect Assessment Model
EC	Electro Chlorinator
ECE	Environmental Chemical Engineering
EIA	Environmental Investigation Agency
EIF	Environmental Impact Factor
GA	Glutaraldehyde
GAB	General Aerobic Bacteria
HOCNF	Harmonized Offshore Chemicals Notification Format
HP	High Pressure
HPLC	High Performance Liquid Chromatography
HPU	Hydrolic Pump Unit
HRG	Hydroxyl Radicals Generator
HSE	Health, Safety and Environment
IOR	Increased Oil Recovery
IPC	Ionized Pair Chromatography
JIP	Joint Industry Project
KLIF	Norwegian Climate and Pollution Agency
MCS	Master Control Station
MIC	Microbial Induced Corrosion
MW	Mega Watt
Mw	Molecular Weight
NCS	Norwegian Continental Shelf
NCR	Natural Resource International
NIPER	National Institute Petroleum, Energy Research
NIVA	Norwegian Institute for Water Research
NPD	Norwegian Petroleum Directorate
NPSH	Net Positive Suction Head
O.e	Oil Emission
OLF	Oil Industries Landsforening
OPEX	Operational Expecditure
PAA	phosphonate polyacrilic acid
QCM	Quality Control Module
RSI	Raw Seawater Injection
SDI	Silt Density Index
SEM	Subsea Electerical Module
SRB	Sulphate Reducing Bacteria
SRM	Subsea Router Module
SW	Seawater
SWIT	Subsea Water Injection and Treatment

TRL	Technology Readiness Level
TSS	Total Suspended Solids
WAG	Water and Gas
WI	Water Injection

Nomenclature

μ	Micron
E_A	Areal Efficiency
E_V	Vertical Efficiency

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Searching for New Technologies That Can Give Environmental Benefits to the Oil Industry
Subsea Water Flooding

1. INTRODUCTION

1.1. Thesis Objectives

In an industry that has a poor environmental image, this thesis investigates how the implementation of new technology can improve oil companies' environmental profiles. In order to do this, the subject of offshore water injection is taken as an example and comparisons are made between the traditional methods of waterflooding from topsides verses new methods of waterflooding from the seabed.

It is perceived that changing from topsides to subsea waterflooding can have significant environmental benefits whilst also improving secondary recovery factors at the same time. New "technology enablers " like the Subsea Water Injection System (SWIT) are combined with more established technologies such as subsea pumping and subsea well technology to provide an overall subsea waterflooding capability. This thesis examines that perception in more detail and investigates how technologies like SWIT can help petroleum's industries to improve their environmental frameworks.

1.2. Background

Climate and Pollution Agency in Norway (KLIF) has in their 2012 annual report published that 29% of total NO_x and 25% of CO₂ emission to the air come from oil and gas activities in Norwegian Continental Shelf (NCS) [15]. From the early days, environmental and climate considerations have always been an integral part of the Norwegian petroleum activities and there has been high focus on technologies that covered all HSE regulations and avoided potential for serious damage to the environment from both operation and installation aspects. In order for operator companies to meet environmental regulations, they should select the best available oil recovery technologies that minimise the emission of the gases into the atmosphere and come closest to achieving zero discharge of hydrocarbon compounds or production chemicals into the sea.

Based on background above, this non-experimental thesis will introduce and examine subsea waterflooding which includes the SWIT method of water treatment and injection as one of the environmentally friendly alternatives to the current method of water injection, namely from topsides. The examination will include test results from SWIT treatment process particularly in relation to chemical injection and power consumption.

1.3. Waterflooding: Potential to Reduce Environmental Impact Factor

Injection of treated seawater into the reservoir from a fixed platform or floating production unit (FPSO) is a known increased oil recovery (IOR) method [4]. Some of the major issues regarding to topside treatment system are that they occupy big space, significant weight problems particularly for FPSO and incur high treatment costs. In addition to being large and heavy, the traditional solutions for cleaning of water on topside are very energy consuming. The treatment processes also require significant chemical usage; chemicals such as biocides, oxygen scavenger, filter aids, scale inhibitors, antifoam and in some cases corrosion inhibitors need to be added to the seawater to make the seawater suitable for injection. Some of these chemicals are not biodegradable and can eventually

make their way to the sea (either accidentally or via produced water discharges) where they are accumulated in the food chain and lead to long time/ toxic effect on environment.[1]

1.4. SWIT Technology

Seabox AS offers a new technology for seabed-based water treatment (SWIT). The SWIT technology achieves the same water quality as a topsides treatment plant in areas that are important for ‘sweeping’ the reservoir and gaining the maximum amount of oil out as possible. It provides both practical and financial benefits as well as much improved flexibility for the reservoir engineer to design the optimum water drive, which in turn increases the oil recovery factor from a reservoir even more. The quality of the injection water after treatment with SWIT has shown an acceptable level for solids reduction, bacterial removal/ disinfection and sterilization of seawater, which in turn encourage several HSE advantages. [2]

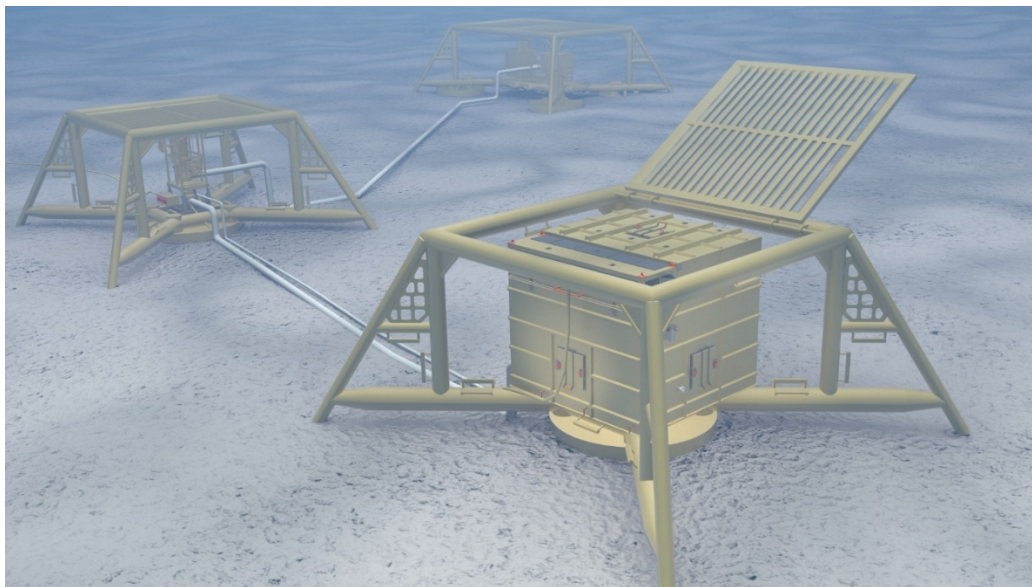


Figure 1.1: SWIT Injection System on the Seabed [Courtesy of Seabox]

A full scale SWIT system was installed for a pilot testing on the seabed in Oslo fjord for the first time in July 2009. The results from this pilot testing has shown a number of advantages for IOR with reference to:

- Facilities
- Wells
- Reservoir
- Environmental aspects

1.4.1. Perceived SWIT Benefits Related to Improvement of Oil Companies Environment Impact Factor

SWIT is a very simple treatment system that generates its own chemicals (Sodium Hypochlorite and Hydroxyl radicals) via electrolysis of naturally occurring elements in seawater. This electrolysis, plus the nature and location of the SWIT treatment process itself,

overcomes the need for many of the chemicals required for a typical topsides plant such as biocides, filter aids, oxygen scavengers, corrosion inhibitors and antifoaming agents.

This represents significant health and safety advantages for operational personnel that would otherwise have to transport, handle and injection these chemicals, plus the environmental benefits associated with reducing consumption and risk of spillage.

In addition, subsea seawater treatment results in significant power savings in not having to lift all injection water up to a platform, perform treatment, boost pressure and distribute via long deviated wells or subsea pipelines. Typical power savings for a subsea injection system are 15% (to get the same amount of treated water to the reservoir perforations). [7]


Further technical details about SWIT technology and other benefits will be found in Chapter 4 later in this thesis.

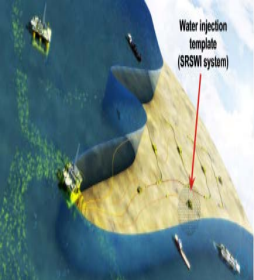
1.5. Historical development of Subsea waterflooding


Non treated ‘raw’ seawater has been injected into reservoirs, via subsea installations, on fields in Norway and other fields around the world. Table 1.1 below give an overview of proven RSWI technologies. It should be noted that, due to ‘raw’ water quality, subsea waterflooding is not considered viable for all reservoirs – only a selected few.

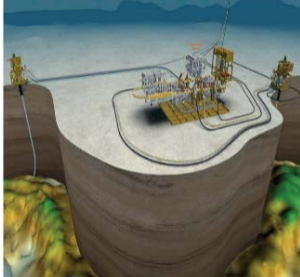
Subsea water treatment is therefore seen as a “technology enabler” for the field of subsea waterflooding and one, which will enable subsea waterflooding for most reservoirs - “SWIT can be introduced as the first subsea system in the world that has implemented control of sterilisation equipment and particle reduction as well as subsea chemical injection”. [8]

Table 1.1: Historical Raw Seawater Injection Technology

Field	Colombia terraces / E field [9]	
Water Injection System	Subsea Raw seawater injection (June 2007)	
History	The world’s first subsea raw seawater Injection system.	
Discovery (year)	1975	

Field	Tyrihans field [10][11] [53]	
Water Injection System	Subsea Raw seawater injection (2007)	
History	The first time Statoil has used this technology	
Discovery (year)	1983	
Estimated Injection Capacity	88000 bbl/d	

Field	Norne Field [12][13]	
Water Injection System	Subsea Raw seawater injection, From Topside (2004)	
History	Subsea WI was developed by Statoil	
Discovery (year)	1991	

Field	Petrobras Marlim filed Brazil [116]	
Water Injection System	Subsea separation and re-water injection treatment system	
History	Subsea WI and separation technology built by FMC technology/ the world's largest subsea development.	
Discovery (year)	1985	

Field	Barton Field [14]
Water Injection System	Raw seawater injection, From Topside
History	Subsea WI (Shell- Malaysia)
Discovery (year)	1982

1.6. Methodology - Summary of how the Objectives will be examined:

This thesis will be organised as follows:

- ❖ Theory
 1. Understanding of waterflooding.
 2. Water injection from topside
 3. Subsea based water injection (SWIT system)
- ❖ Comparison of topsides waterflooding with subsea waterflooding based on:
 - Water Quality and chemical usage
 - Energy Consumption (power)
 - Offshore manning
- ❖ Environmental Aspects of SWIT
 - CO₂/ NO_x Emission to the air
 - Discharge of Chemicals into the sea
 - Environmental effect of chemicals based on their toxicity
- ❖ Case study

2. UNDERSTANDING THE FUNCTION OF WATER INJECTION FOR INCREASED OIL RECOVERY IN OIL & GAS INDUSTRY

2.1. Oil Recovery Strategies

Hydrocarbon reservoirs are comprised of porous natural rock formations containing a mixture of oil, gas and water. Initially, oil and gas is produced from reservoir by naturally hydrostatic pressure of the ground water or by artificial lift through a single well bore. In oil and gas industry, this is called “Primary Recovery”. The natural pressure underground is slowly depleted when fluids are extracted continually from a reservoir. Eventually the decline in pressure will cause the oil recovery rate to become low and uneconomic. In order to overcome such an issue and maintain pressure, water will be injected into the reservoir. Historically, in offshore industry, these techniques have been called for “Secondary Recovery” because the fluid injection results in a second ‘crop’ of oil from the reservoir [16]. Figure 2.1 illustrates recovery methods in oil industry.

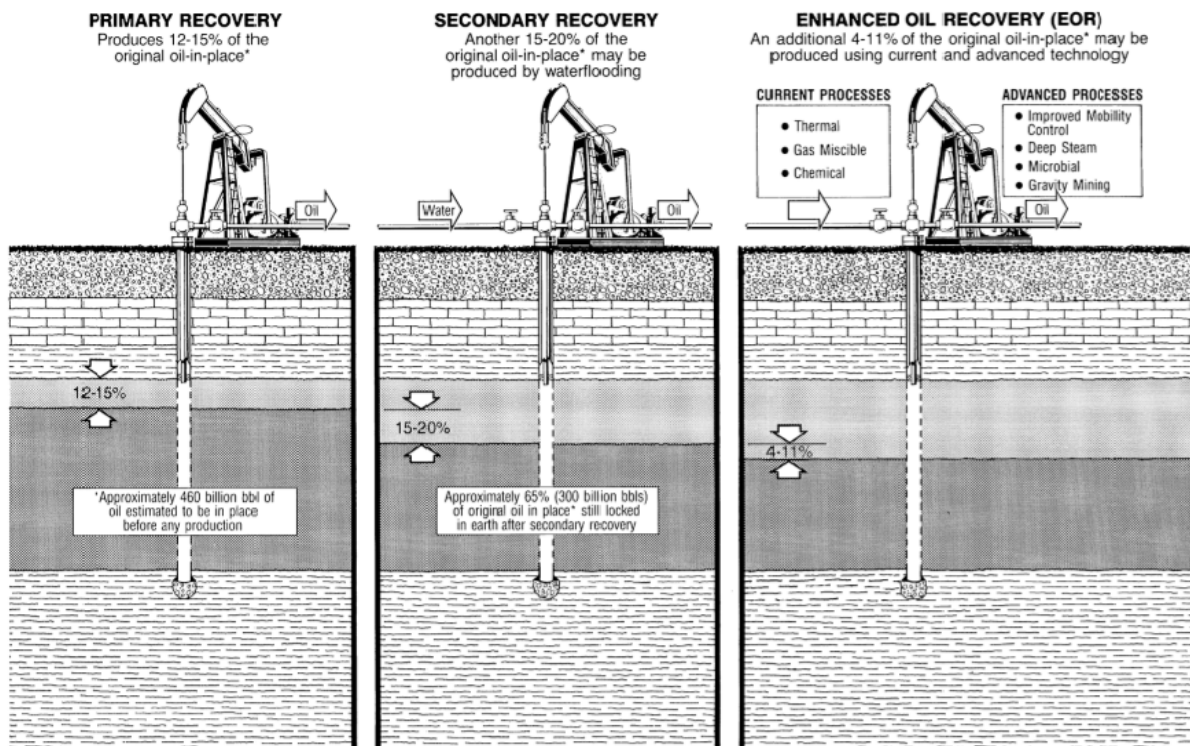


Figure 2.1: Three Oil Recovery Methods [Courtesy of NIPER]

2.2. WaterFlooding

Water injection is the most used worldwide method for displacing of oil and pushing it into the oil wells to improve recovery of hydrocarbons. Water is pumped into the productive stratum through pressure bore holes in a volume equal or more than the volume of oil produced. [103] [104]



Figure 2.2: The Concept of Waterflooding [Courtesy of Maveric Energy]

Three key factors listed below have the main responsibilities in the success of waterflooding technique and recovery of billions of barrels of oil per day in an economic fashion. [3]

- Source water
- The ability to inject required volume of water into the formation under the pressure gradient of the reservoir (treatment conditions)
- Reservoir properties

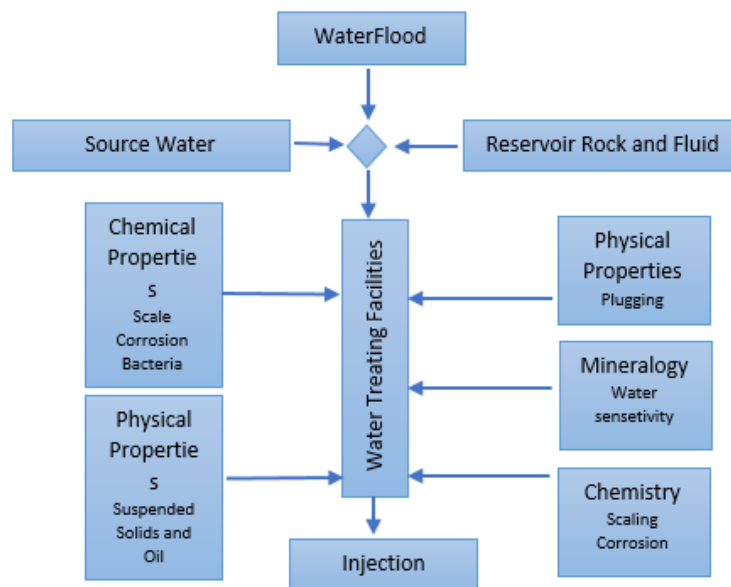


Figure 2.3: Three Key Factors in Waterflooding Management System [3]

Some of the simple questions that normally emerge in this context are:

1. Why is water used for commercial recovery process in oil industry?
2. Are reservoir engineers applying a specific waterflood pattern for injection?
3. How was waterflooding technique discovered for the first time?

2.2.1. Reason for Water injection

The main reasons to use water for waterflooding are: [4] [5]

- Water is normally readily available in nature
- Water injection process is relatively simple
- Water can flow/move through an oil formation and is therefore an efficient liquid for displacing oil
- Economic aspects are very favourable investment in comparison with other techniques – e.g. CO₂ injection and other so called tertiary recovery methods

2.3. Waterflood Pattern

Reservoirs are not uniform in the rock and fluid properties. These differences can be both in areal and vertical portion of the reservoir and put restriction on sweep efficiency in mentioned regions (E_A , E_V). Therefore, reservoir engineers depend on the geology of the reservoir and identify possible ways (e.g. implementing an efficient flooding pattern) to

Inject water into the reservoir and enhanced oil recovery. There are various types of waterflooding

patterns and most common of these are “Peripheral Flood” (Circle Flood), “Line Drive” and “Four/Five or Nine Spot”.

The size and kind of these patterns are depend on both rock formation and production well location. When water is injected from customised patterns and flows through formation rocks in a matrix fashion, the sweep efficiency of waterflood increases, thus much more oil is pushed forward (swept) to production wells. [105]

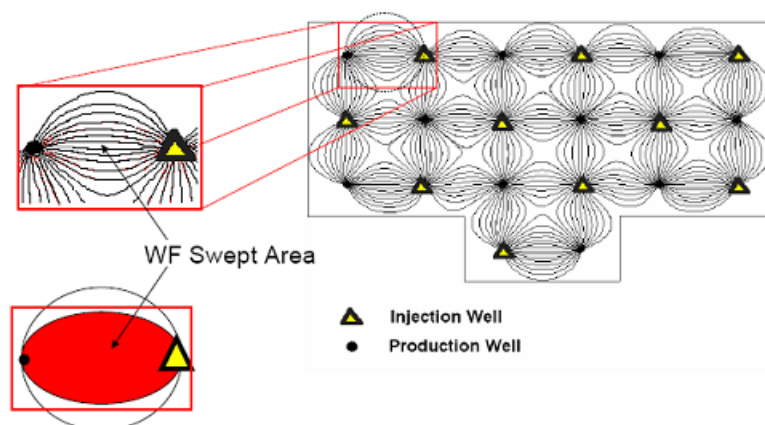


Figure 2.4: Reservoir Sweep Pattern [22]

2.3.1. Peripheral Flood

Peripheral flooding is one of the most favoured waterflood patterns where injectors are located around the periphery of the reservoir. Typically, when the outermost of the producing wells cease to become economic, they are converted over to water injection wells. Injection in a peripheral flood gives both pressure maintenance and water drive. [106]

2.3.2. Line Drive

Line drive is a pattern flooding that the injectors and producers are distributed on a direct line. Line drive is divided in two configurations either direct or staggered line drive.

2.3.3. Five Spot

Five or nine spots are similar to line drive and injectors are distributed among the produces in some repainting fashion. For instance in a five spot drive, four injectors are drilled at the corners and a producer in the centre. The selection of the type of the pattern will depend on circumstances in a given field.[108]

Figure 2.5 shows various types of the waterflooding patterns. It should be noted that reservoir engineers during the life of the waterflood process change the injector, producer pattern and well spacing in many cases with the objective of maximising oil recovery.

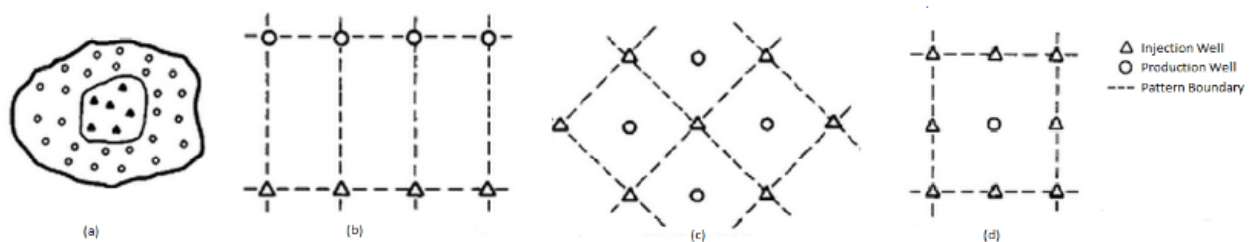


Figure 2.5: (a) Peripheral Flood, (b) Direct Line Drive pattern, (c) Five Spot pattern, (d) Nine Spot pattern [108]

2.4. History development of Waterflood

The adventure of Water flooding started for the first time in 19th century. Documents have shown the first waterflood occurred in Pennsylvania Bradford Field in 1905. The reason for the flooding was described as an accidental water injection in Pithole city. Accidental flooding had effect on increasing the production rate in the field during that time and the favourable results on increasing oil recovery has introduced waterflooding as a technique for maintain the pressure on mature field when the reservoir pressure has fallen below the bubble point pressure. Waterflooding was not legal until 1921 and operator company Carter Oil has extended waterflood activities for the first time outside of Pennsylvania in 1931. "Circle pattern flooding" was the first method that spread from Pennsylvania to Ontario and other states [6] [104]. Expansion for onshore waterflood projects was much more rapid after 1950s.

Offshore waterflooding was pioneered in the 1970's with field waterflood systems seen in the middle east and the UK sector of the North Sea. For the Norwegian sector of the North Sea, Ekofisk was the first field that has used waterflood technique to maintain reservoir

pressure in the 1980's. More information about waterflood development is addressed in reference [107].

Many issues, including well placement and geometry of reservoir in addition to poor water quality can affect the success of a potential injection process. Injection of water with poor quality can reduce an effective injection and created reservoir issues. The result of such problems will lead to economic failures and costly workovers. It is for these reasons that an analysis/monitoring of source water must be carried out in order to determine injection requirements. Based on these analysis the correct amount of treatment, either chemical or mechanical, can be identified. The following sections will review the common water sources and evaluating reservoir issues related to injection water with poor quality. Suggestion and possible solutions for improvement of water quality and reduce problems related to reservoirs will briefly be discussed. The flow chart below gives an overview on which areas will be affected due to unsuccessful secondary recovery.

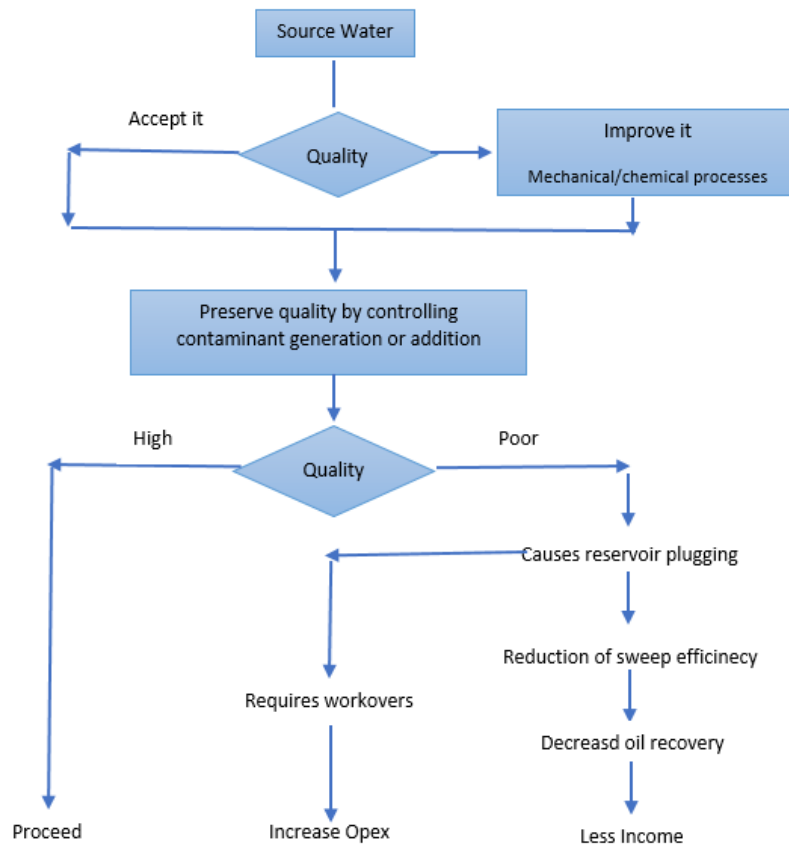


Figure 2.6: Poor Water Quality and Affected Area [3]

As can be seen water injection has continued to develop from the onshore field applications of the 1950's to the offshore systems of the 1970's. The most recent developments now include for water injection from the seabed.

2.5. Common Injection Water Sources

Water that is injected into porous formations for waterflood can be taken from various sources and locations. Water chemistry factors such as temperature, pH, pressure, compatibility and seasonal variations are common in all types of water sources regardless to location. However, factors such as chemical composition and salt concentrations of waters are different. Table 2.1 shows typical water chemistry factors. Common sources of water include produced formation water, surface water (e.g. lake, river, seawater and ocean), fresh water (shallow groundwater) and deep aquifer. Figure 2.7 illustrates the location for water sources.

Based on provided information in different references, lake and river water contain very small amounts of salt, low quantities of dissolved oxygen and suspended solids (e.g. clay, phytoplankton and zooplankton substances). Deep aquifer water that comes from layers close to the oil layer in reservoir can contain high levels of dissolved oxygen, corrosive gases (e.g. CO₂ and H₂S) and harmful bacteria (e.g. Sulphate Reducing Bacteria). These bacteria has a pioneer role in formation of biofilm and corrosion issues on equipment and within the reservoir. They will be discussed later.[16] [109]

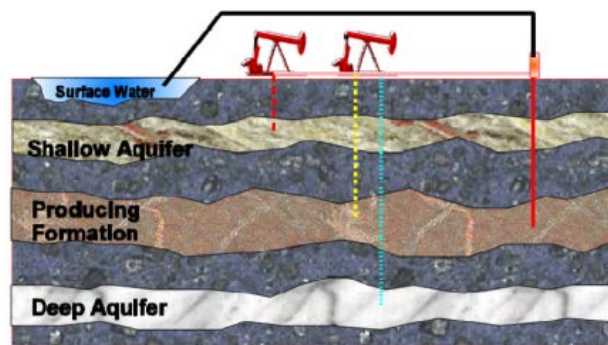


Figure 2.7: Injection Water Sources [109]

Table 2.1: Introduced the various compositions that may be found in the seawater for injection. [104]

Dissolved	Solid	Minerals	Anions (-)	(Cl ⁻), (Br ⁻), (F ⁻), (CO ₃ ²⁻), (SO ₄ ²⁻), (CO ₃ H ⁻)
			Cations (+)	(Na ⁺), (K ⁺), (Ca ²⁺), (Mg ²⁺), (Fe ²⁺), (Mn ²⁺)
		Organic	Plant and animals (Plankton)	
	Gases	(O ₂), (H ₂ S), (CO ₂)		
Suspension	Minerals	Fe(OH) ₃ , SiO ₂ , Clay and mud		
	Organic	Algae and Bacteria		

2.6. Water Quality and Reservoir conditions

Water quality is a key factor and can be identified as the sum total of all chemical, physical and microbiological properties required for a water to be suitable for specific application and it is depend on field's or reservoir conditions. Water quality is depend on

dissolved components, suspended components and a variety of other variables such as temperature, water depth, daily and seasonal variations.

With reference to the above information, it can be concluded that reservoir characteristics (e.g. “open” or “tight”¹ reservoir) are very important factors and play an important role on permeability, porosity levels of wells and will set water quality requirement for injection. Therefore, reservoir engineers should evaluate all aspects related to water quality in order to reduce damages associated with poor water quality injection [19]. This will help operator companies to carry out an environmentally safe and cost effective water injection and treatment process. Some of these aspects are discussed below.

2.6.1. Microbial effects

A wide range of indigenous aerobic and anaerobic bacteria is present in water and plays an important role, either directly or indirectly on the problems related to water injection operation. Given favourable conditions, bacteria may grow in surface equipment, pumps, tubing, downhole equipment as well as within the formation itself. Problems associated with bacterial activities in water injection system and injection wells are divided in three areas such as biofilm formation (plugging), microbiologically induced corrosion (MIC) and reservoir souring (H₂S production via Sulphate Reducing Bacteria).

2.6.1.1. Biofilm Formation

Bacteria need ideal environmental conditions such as temperature, nutrient, salt concentration, pressure to survive, grow and proliferation. When bacteria have received ideal conditions, a large amount extracellular polymer called biofilm will be formed. Build-up of biofilms contain various steps such as attached, grow, multiply, detached from the water surface and adhere/stick on surface of material as a glue. Fouling on the surface and plugging of porous media due to the build-up of biofilm lead to reduction in water injectivity into the wells, less water flow and loss of crude oil reserves. Biofilms most often consist of species such as fungi, algae, protozoa and corrosion products.[4] [103]

¹ Open reservoir: A reservoir with high permeability therefore, able to accept large particles in the injection water.

Tight reservoir: A reservoir with low permeability.

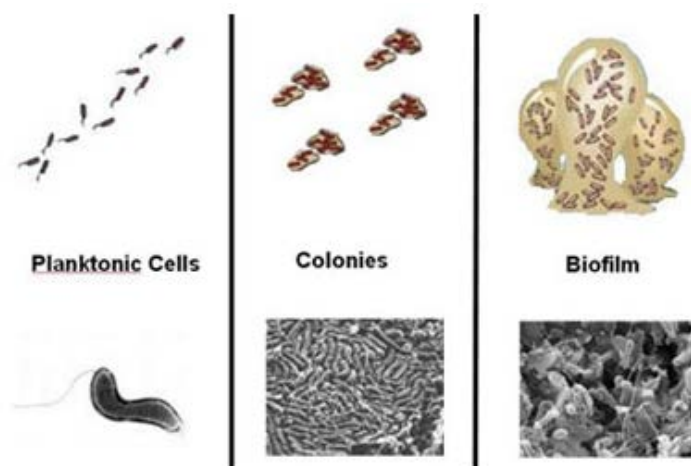


Figure 2.8: Development of Biofilm [Courtesy of Wikipedia]

2.6.1.2. Sulphate Reducing Bacteria

Amongst thousands of types of bacteria, sulphate reducing bacteria (SRB) are a significant problem found in many oil and gas field operations. From oil companies and environmental authorities' point of view, these bacteria are undesired and result in daily operational problems. Proliferation through the oil reservoir via injection water contaminates equipment due to their toxic and corrosive products. [38]

SRB need conditions such as suitable source of nutrient (e.g. C, H and P), sulphate, ideal environmental conditions (e.g. oxygen free, neutral pH, normal salinity and temperature) and pressure less than 400 atmosphere for replication, growth and harmful activities. [4] [41]

Anaerobic reaction between produced metabolised hydrogen with elemental sulphate presented below shows how toxic and corrosive H₂S will be produced.



Some of the serious issues due to the generation of H₂S gas include souring of the reservoir, environment, health and safety hazardous and risk conditions, costly biocorrosion problems (e.g. hydrogen embrittlement) and increased maintenance requirements for topside water injection system.

Reservoir Souring

The phenomenon of reservoir souring is also known as an undesired condition in the oil industry and if not properly addressed can occur during the water injection process. When SRB are introduced into the producing formation and other necessary conditions for growth are satisfied, SRB are capable of converting inorganic sulphate ions into H₂S using different

types of organic compounds as a reducing agent. In this case, a sweet oilfield become sour and it is called reservoir souring.

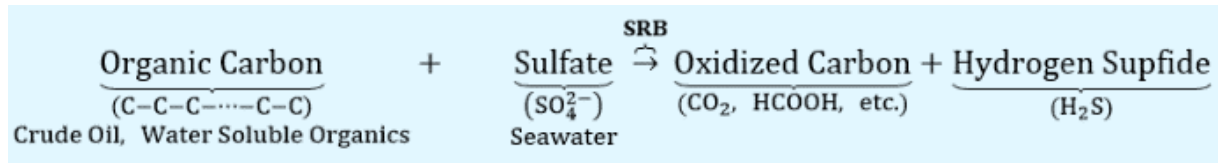


Figure 2.9: Anaerobic Biological Activities of SRB [22]

Field data from Gulfaks A, Snorre A and Norne on the NCS have reported that these fields become sour due to the SRB activities after water injection application. [42]

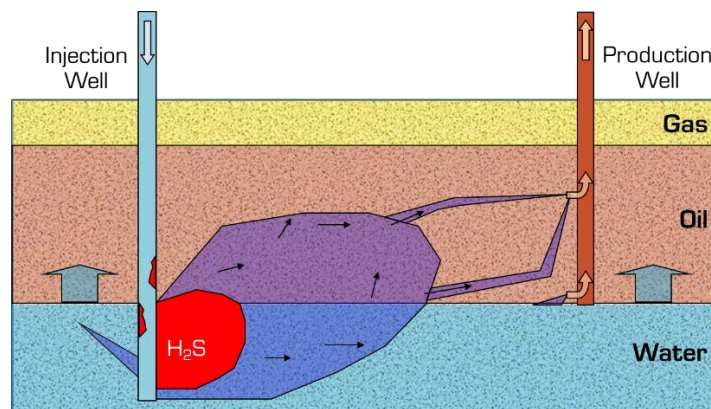


Figure 2.10: Sulphate Reducing Bacteria Activities and Resulting in Reservoir Souring [Courtesy of Seabox]

Since reservoir souring is undesirable, the ability to predict H_2S generation and modeling the reservoir souring are beneficial aids. For these reasons, several mathematical models have been developed, based on bacterial growth rate, nutrient amount, water mixing zones, transportation and adsorption of H_2S within the reservoir. [43] [68]

1. Biofilm Model

In earlier parts, it was addressed that H_2S gas was produced under biofilm formation in the well and near the well bore area. Sulphide is then transported to the producing well by the existing pressure gradient in the reservoir.

2. Mixing Zone Model

This model is based on production of H_2S in the mixing zone between formation water and injection water. In mixing zone model factors such as well geology and orientation are very important constraints. Therefore, the mechanism of H_2S generation by mixing zone model is more complicated than the biofilm model.

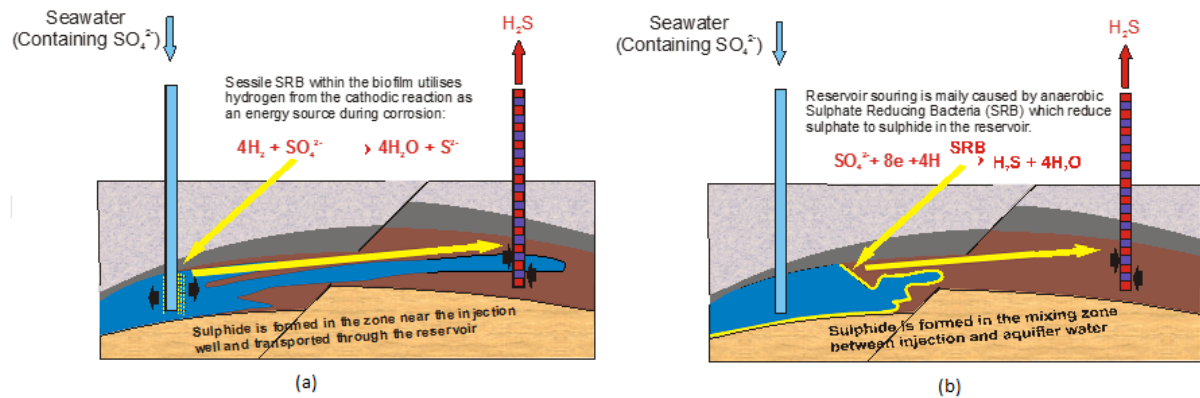


Figure 2.11: (a) Biofilm Model, (b) Mixing Zone Model [68]

The presence of suspended solids in the injection water is one of the major issue in water quality and has effect in water injectivity results. These solids will usually reduce the effective pore throat size in the reservoir rocks and causing restriction or barrier to flow. Once the solids injected into an injection well can cause formation of filter cakes on the formation face or can enter the rock pore space. The result of both scenario is the loss of effective permeability of the injection zone, which usually leads to increase in injection pressure. A reservoir specific coreflood analysis will usually be carried out to determine the potential injectivity loss caused by suspended solids in the injection water. Nevertheless, if no suitable material is available for core analysis, common “rule of thumb” data is available to estimate the size of suspended solids and the tendency of pore blocking.

Based on these rules, particles suspended in injection fluids that are larger than 33% (1/3) of the median pore throat diameter, will logjam together and build a bridge and form a ‘filter cake’. This increases the potential of permeability reduction.

The removal of internal filter cakes are very difficult. Pressure (hydraulic) fracturing or acid fracturing of the reservoir injection zones can be used to regain injectivity.

Particles having a median diameter less that 1/7 of the median pore throat size are very desirable, because they will pass easily through the porous medium. A variety of techniques will be used to combat these problems. For instance filtration methods. [4] [103] [104]

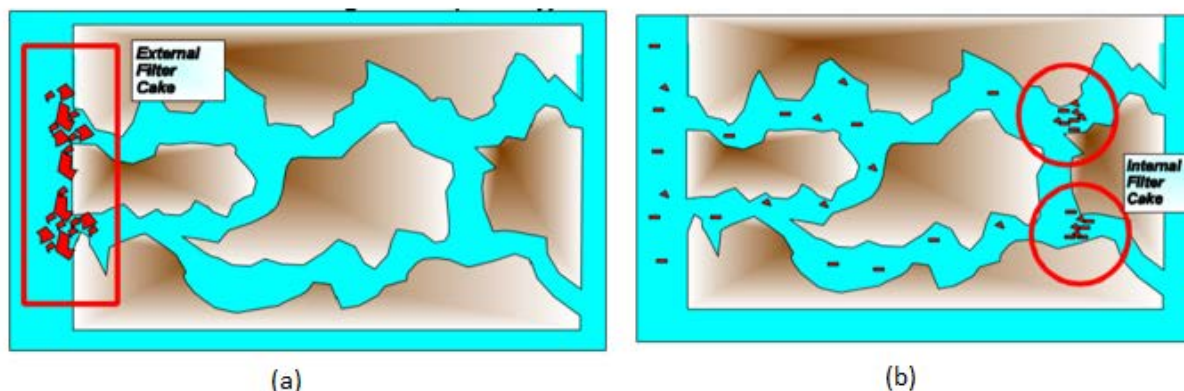


Figure 2.12: (a) Illustration of external Filter Cakes, (b) The Formation of Internal Filter Cakes [109]

2.6.2. Scale Formation

Precipitation will form when two incompatible waters (e.g. seawater and produced water) are mixed or a single water undergoes a series of chemical and physical changes (e.g. pH, Temperature or pressure) that lead to reduction in solubility of water components. In oil field industry, the mechanism of solid precipitation is called scaling. Two major types of scaling are commonly encountered in oil industry for water injection operation. Carbonate and sulphate based scale formation.

Carbonate scale (e.g. CaCO_3 scale) is formed when injected water passes from the surface into the formation. The most common reason for this formation is changes in pressure, temperature or pH of the injected water and loses of CO_2 .

Sulphate scale (e.g. BaSO_4 scale or CaSO_4) is mostly formed in the case of incompatibilities between two waters when they come in contact with each other in the producing wells or the surface production facilities. For instance seawater with high sulphate mixing with produced water that contains high level of barium resulting in BaSO_4 scale. [4] [114]

The next chapter will discuss the mechanical and chemical methods that will be applied by Operators Company in order to avoid the tendency of scaling in water injection systems.

2.6.3. Compatibility/ Injection Water Interaction and Formation Damages

There is always a significant difference in the composition and concentration of the injected water and produced water². This leads to a potential for detrimental interactions related to injection water and formation damages. Once the chemical compositions and concentrations are incompatible between injection water and formation water, a chemical reaction will occurred due to the permeability impairment from water and reservoir rocks interactions. This is called clay swelling. [110] [111]

Clay Swelling

Smectite or mixed layer clay is one type of reactive clay presents in many sandstone formations targeted for injection. The crystal structure of smectite consists of AlOH , FeOH , MgOH and SiO layers. Due to cation substitution, these crystals always hold negative charges

² Produced water is the formation water that has been in contact with reservoir rocks for a long time.

and can easily exchange the cations with water. Therefore, smectite clay is prone to clay swelling problem. Once this process occurs cations from the water molecules diffuse between the clay layers and the gap between these layers increases resulting in larger volume clays. Figure 2.13 shows the mechanism of clay swelling.

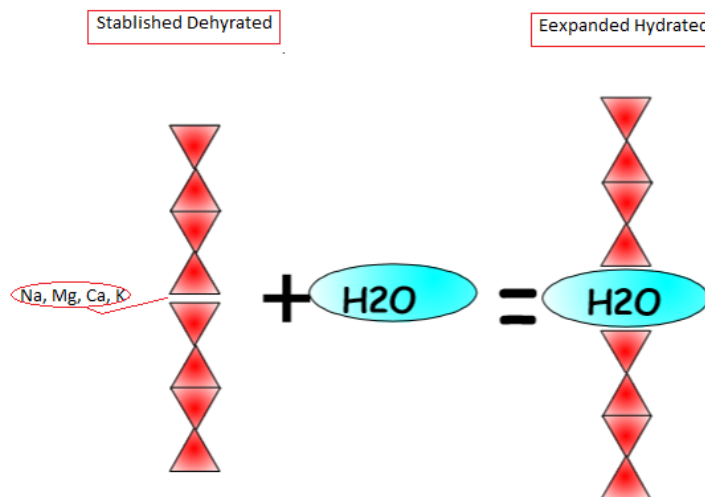


Figure 2.13: Typical Expansion of Clay Swelling[109]

The degree of clay swelling depends on the composition of the permeating water and nature of exchangeable cations. [3]

2.6.4. Corrosion Control

Generally, corrosion is defined as an electro chemical process. In waterflooding process, corrosion is a well known issue to limit the useful life time of the equipment and it is a very costly item. Therefore, a solution to avoid corrosion should be applied when an unstable metal is exposed to aqueous environment. Corrosion can be classified in two categories, general corrosion and localized corrosion. [4] [103]

General corrosion

General corrosion occurs over a large area and leads to large amount of corrosion product to the system. In general, corrosion, one of the major concern of water quality problem is the presence of dissolved iron (Fe). It should be note that dissolved iron in itself is not a problem,

except in steam floods system. The problem will be created when iron react with dissolved oxygen and sulphide in injection water (e.g. corrosion in water injection equipment and oil-water separation systems).

Localized corrosion

Localized corrosion is the other type of corrosion in which there is intense attack at localized sites on the surface of the component and the rest of the surface will be corroded at a lower rate. Because of formation of a protective oxide film or some environmental effect. The most famous type of localised corrosion is pitting [113]. Microbiologically Induced Corrosion (MIC) below is one such form of localised corrosion.

Microbiologically Induced Corrosion (MIC)

The chemical and physical activities of the microbial inhabitants within the biofilm is usually not homogeneous. Therefore, situation for formation of an effective anode and cathode (Corrosion mechanism) is present from localised bacterial activity. The corrosion mechanism will happen in the border site of the biofilm and surface of the metal and this form of corrosion or pitting is called MIC. Because both bacteria and biofilm are available [44] [109]. Figure 2.14 shows MIC mechanism.

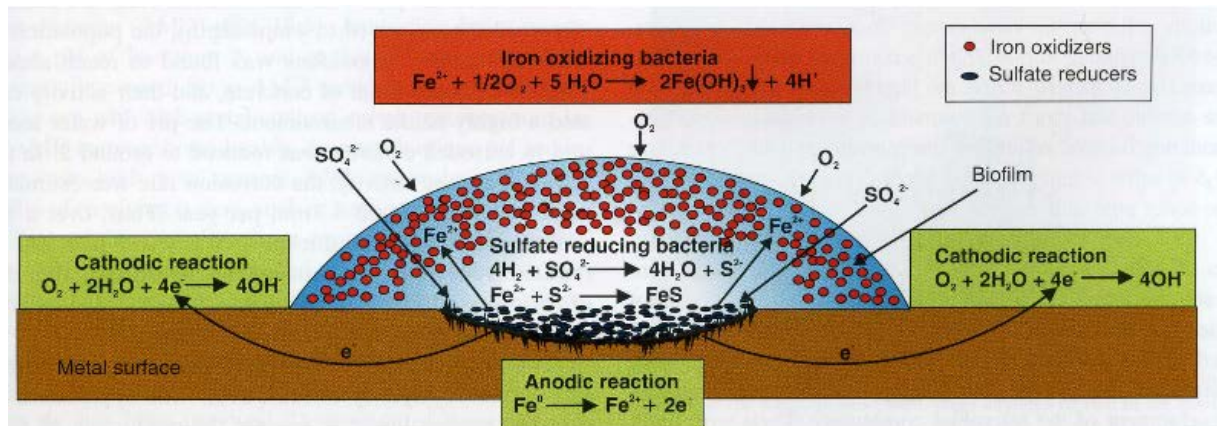


Figure 2.14: Mechanism of Microbiologically Induced Corrosion [Adapted from Environmental Microbiology Course Lecture, Uis]

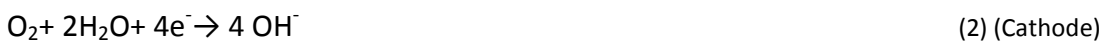
Dissolved gases

The water analysis results have shown that corrosive gases such as oxygen (O₂), carbon dioxide (CO₂) and hydrogen sulphide (H₂S) normally found in oil field waters. The acid gas content determines the dominate type of the corrosion and corrosion rate are directly depends on the amount of these gasses dissolved in water in combination with the dissolved chlorides. [19] [112]

Oxygen (O₂)

Surface water contain up to 14 mg/l of oxygen depending on temperature and salinity of the water. The solubility decreases with increasing the temperature and salinity but increase with pressure. Figure 2.10 shows at even parts per billion, seawater can be corrosive.

Equations below illustrate how oxygen corrosion occurs.



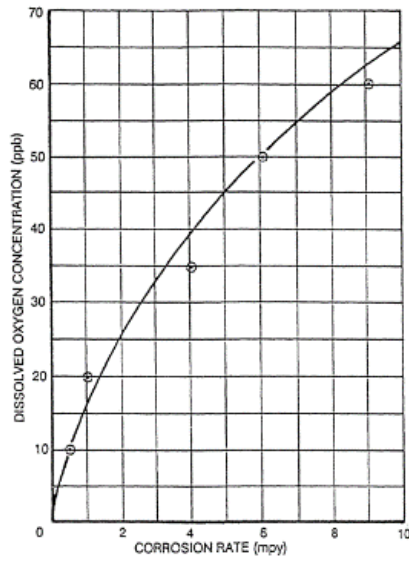
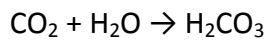


Figure 2.15: Effect of Oxygen Concentration on Corrosion of a Steel in Seawater [19]

Carbon Dioxide (CO₂)

Carbon dioxide form carbonic acid, when dissolved in water. CO₂ corrosion is directly related to its concentration and the system pressure. With increasing pressure, the CO₂ solubility increases, reducing the pH and making the water more corrosive (e.g. pitting).



(4) (Corrosive reaction)

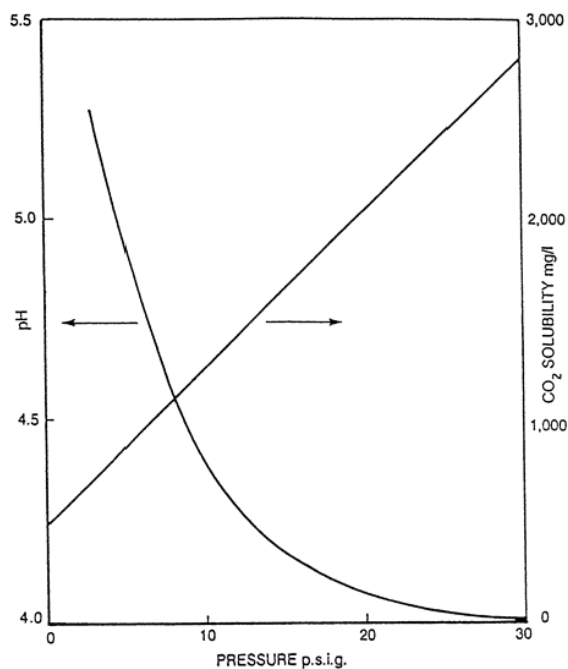
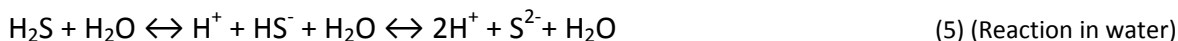


Figure 2.16: CO₂ solubility and pH versus pressure [19]

Hydrogen Sulphide (H₂S)

The third gas that causes corrosion in water is H₂S. This gas forms a very weak acid, when it is dissolved in water.



H₂S gas normally react with iron in water injection system, resulting in insoluble iron sulphide (FeS). This product usually adhere to the surface of pipe work as a scale form, which will then further encourage corrosion by forming anode and cathode areas on the surface. With reference to the equation below, it can be seen that H₂ is formed as a by-product of the corrosion reaction and leads to blistering and embrittlement through the steel.

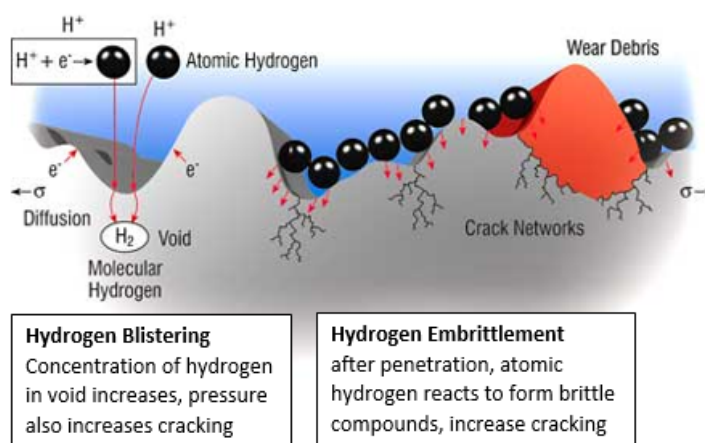


Figure 2.17: Hydrogen blistering and embrittlement [Adapted from Machinery Lubrication Journal]

Several techniques and programs based on water analysis are employed to control corrosion in water very early in the system by corrosion engineers. The next chapter gives an overview of these solutions.

2.7. The importance of Water Quality

The importance of water quality in maintaining long-term water injectivity in injection wells has been discussed in detail in this chapter. Based on discussed factors, it can be concluded that the ideal injection water for industry requirement and second recovery application would have:

- No suspended solids that could plug the injection wells or foul the surface of the equipment and pipes.
- Been disinfected with regard to bacteria – thus eliminating possibility for microbiological growth.
- No dissolved solids or gases that cause corrosion or scale formation.

Lab test analysis/ water quality monitoring is absolutely essential and must be conducted during the operation of a water injection system to ensure acceptable injection water quality

is present. In connection with this, a summary of the essential lab test protocols that are commonly used to related the reservoir and water quality data together for evaluation purposes are illustrated in Table 2.2.

Table 2.2: Description of various test protocols for water quality evaluation. Adapted from [109]

Parameter	Method Description	Comments about Required Quality
Basic Reservoir Quality Permeability Mineralogy Porosity	Pressure Transient Analysis Routine Core Analysis Drill Cuttings Analysis Petrographic Analysis (e.g. thin section, scanning electron microscopy, x-ray diffraction, image analysis)	-
Water Composition	Standard Analytical IPC Technique	Identify and separate environmental contamination from water
Total Suspended Solids (TSS)	Pressure Filtration	Also was practically possible sweep efficiency
Size Distribution of Suspended Solids	Laser Microtrac analysis	-
Composition of suspended Solids (e.g. Si, K, Mg, Ca)	Elemental Analysis X-ray Diffraction	-
Scale Analysis	Numerical Tomson Method Turbimetric Method	Sulfate (ppm) < 20-50 Scale prevention
Bacteria Analysis (SRB) (GAB)	Full Culture Analysis Serial Dilution Method	Also was practically possible Biofouling and reservoir souring prevention
Dissolved Oxygen Content	Dissolved Oxygen Meter	Oxygen (ppm) <5-7 Corrosion protection
Dissolved Gas Content (e.g. CO ₂ , H ₂ S)	High Temperature Solubility Test	Liberate Dissolved Gases
Critical Salinity Test	Special Core Analysis	Determine the minimum ionic and cationic composition and pH required to reduce or eliminate permeability reduction due to injected water, clay interaction, includes the simple salinity shock test (abrupt transition from formation to injection water). If the results of this

		test are unfavorable, so phisticated gradual staged salinity reduction tests and other tests to investigate the effect of presence of various cationic stabilizers on system permeability.
Critical Filtration Test	Special Core Analysis	Determine the maximum size of the permissible filtration allowed to retain particles large enough to cause plugging and permeability reduction in formation.
Bacteria Growth Test	Special Core Analysis	Investigate the plugged effect of bacteria that introduced into porous media and prevention of filter cakes

Many authors in different published articles about source water quality (based on common water quality monitoring tests) have concluded that an ideal injection water for injection purposes does not exist without treatment.

Therefore, a series of mechanical and chemical treatment methods should be used in order to approach the desired water quality. Next chapter deals with the necessary chemical and mechanical methods as aids to operator companies to treat seawater on topside prior to inject it into the reservoir to increase oil recovery.

3. TOPSIDE WATER INJECTION SYSTEM

This chapter describes typical water treatment techniques for injection of seawater into the reservoir from a topside treatment facility. Equipment used for topsides treatment systems, chemical dosage system, materials etc. differ from field to field. Factors such as quality of sourced water, location of the field, reservoir conditions and capacity on production facilities are key elements for selection of a specific treatment plant. In order to understand how a topside injection system related to a specific field works, different parts of treatment plant such as mechanical and chemical treatment packages, typical injection chemicals and their dosage system, power generation suppliers and materials will be described in following sections.



Figure 3.1: Water Injection Unit on Offshore Process Platform [Courtesy of ABB]

3.1. How Waterflooding is performed from a Topside Facilities

As previously stated, in order to increase oil recovery and production of oil, seawater is injected into the reservoir to maintain the reservoir pressure and push (sweep) the remaining oil toward the production wells.

Injected seawater must therefore have a quality that is compatible with both the reservoir and materials used in the well to prevent reservoir plugging, bacterial growth and corrosion issues.

In order to achieve satisfactory injection, water treatment plants on production platforms are equipped with combinations of lift pumps, filtration units, deaeration units, booster

pumps, chemical injection skids, sulphate removal packages and high water pressure injection pumps. [18]

It should be noted that beside mechanical/ physical treatment, various types of chemicals are dosed to the system in order to improve the function of each unit (e.g. suspended solids removal, reduction of dissolved oxygen and biological active substances of the seawater).

Treated seawater is then pumped via flow lines into the reservoir through platform based injection wells. In some cases, treated water can be transported out to the satellite fields and subsea injection wells by long flow lines [2]. Figure 3.2 illustrates traditional seawater injection.

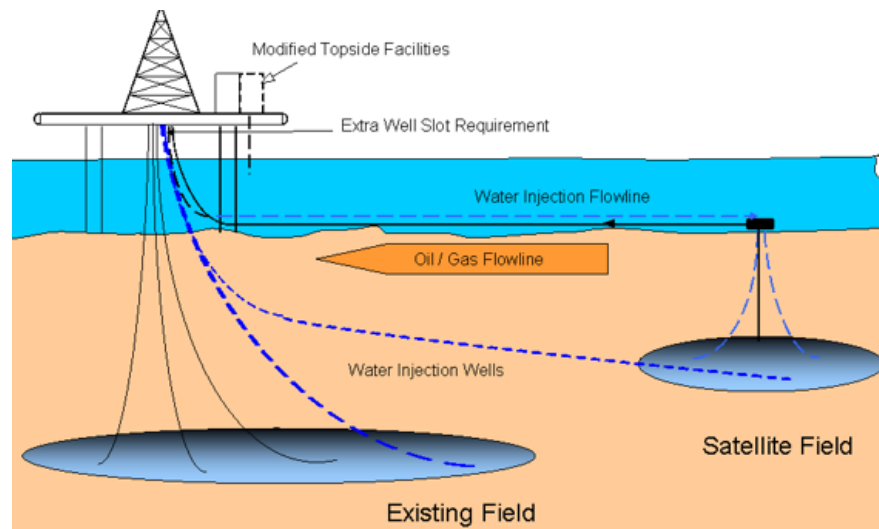


Figure 3.2: Traditional seawater injection [2]

3.2. Treatment of Seawater prior Injection

A typical water treatment plant may contain all or some of the following major equipment.[19]

- Seawater lift pumps
- Coarse Filtration/ Strainers
- Electro Chlorinator
- Fine filtration
 - Media filters
 - Cartridge filters
 - Ultrafiltration/ Microfiltration
- Oxygen Removal/ Deaerator
- Sulphate Removal Unit
- Water injection Pumps/ Booster Pumps
- Chemical Injection Units (up to 7 different types of chemicals)

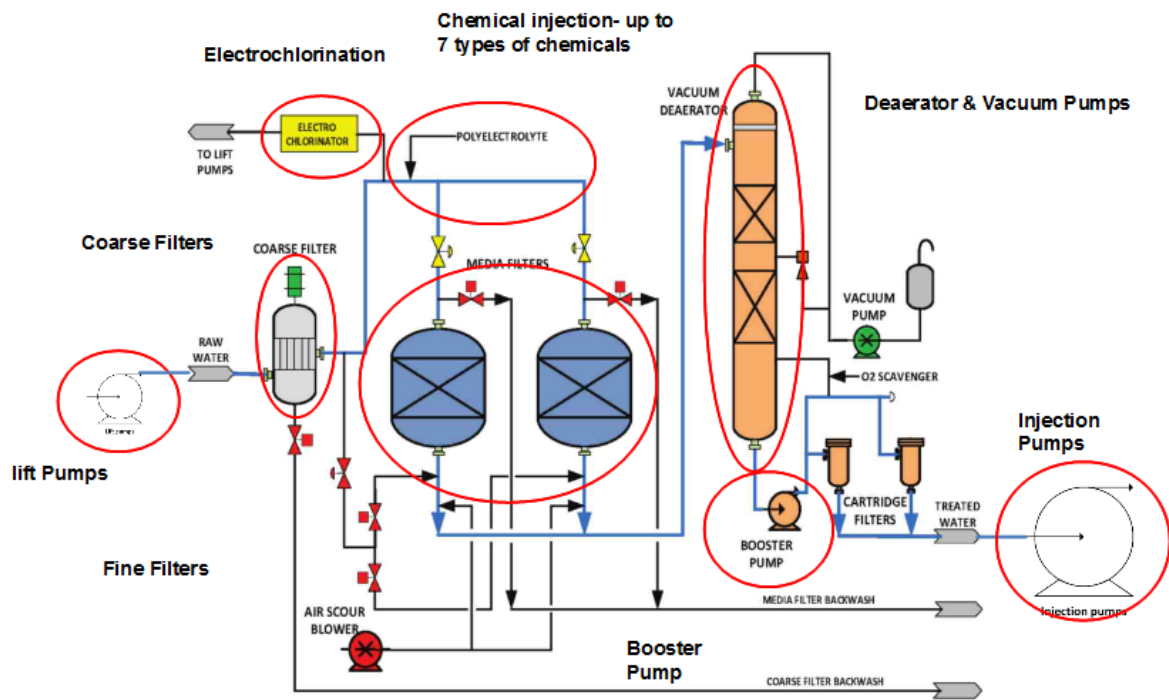


Figure 3.3: Typical Topside Water Injection System [Courtesy of Prosepe]

3.3. Process Equipment and Materials

3.3.1. Seawater Lift pumps

In seawater application, raw seawater is lifted up on platform (e.g. fixed or floating production unit) from a certain depth, above the seabed and below the water surface typically by various seawater lift pumps. Figure 3.4, shows the pumps on both types of platforms. These pumps provided the requirement pressure for water to flow through filters and to the top of the deaerator.

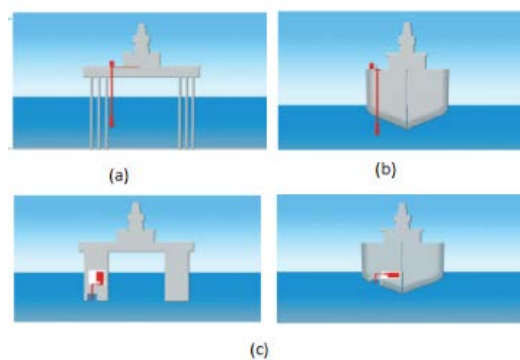


Figure 3.4: (a) Line Shaft pump on fix platform, (b) Electrical Submersible pump on FPSO, (c) Hydraulic Submersible pump [Adapted from Wikipedia]

3.3.2. Coarse Filtration

Filters are located on various locations in the water injection treatment plant to remove contaminants from the seawater. The first filtration unit that water flows through it is known as coarse filter. Coarse filters remove particles and contaminants such as silica sand, large

organic material, mussel shell etc. down to a size of 80 µm- these solids, which can be observed easily by the naked eye. The filter is cleaned automatically with rotational backwash equipment when cleaning process is required. [19] [20]

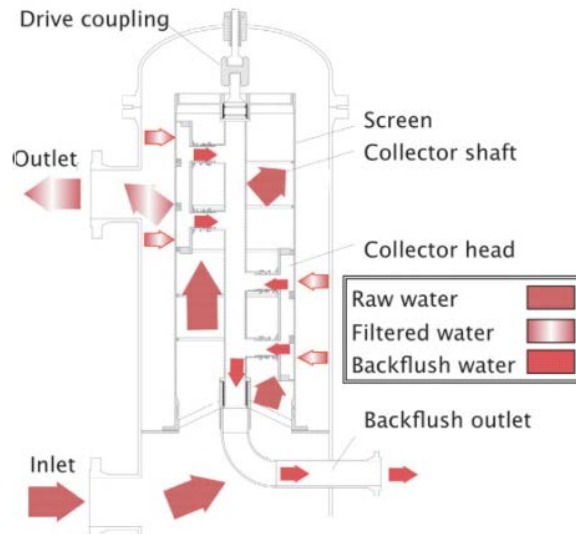


Figure 3.5: Coarse Filtration [24]

3.3.3. Chlorination

Seawater should be disinfected to prevent biological growth before injection into the wells. Chlorine is a universal water disinfectant chemical and has the effect of minimising or killing bacteria. In addition, it can control formation of marine fouling by preventing the growth and reproduction of fauna³ and infauna⁴. From an environmental and safety point of view, chlorine is known as very toxic (poisonous) chemical and must be handled with care. Therefore, due to safety reasons, electrolysis has been prioritised for generation of chlorine in offshore WI treatment facilities instead of using liquid chlorine. [16]

Electro Chlorinator

An electro chlorinator in a seawater treatment system contains two electrodes - an anode and a cathode. D.C. current passes through the seawater from anode to cathode. This results in converting the H⁺ ions to H₂ gas at the cathode side and a solution of sodium hypochlorite (NaOCl) being generated at the anode side [4] [21]. Equations below show a typical electro chlorination reaction and Figure 3.6 illustrates sodium hypochlorite generation cells.



³ Fauna: typical collection of small animals growing on the sediment.

⁴ Infauna: Typical collection of small animals growing within the sediment.

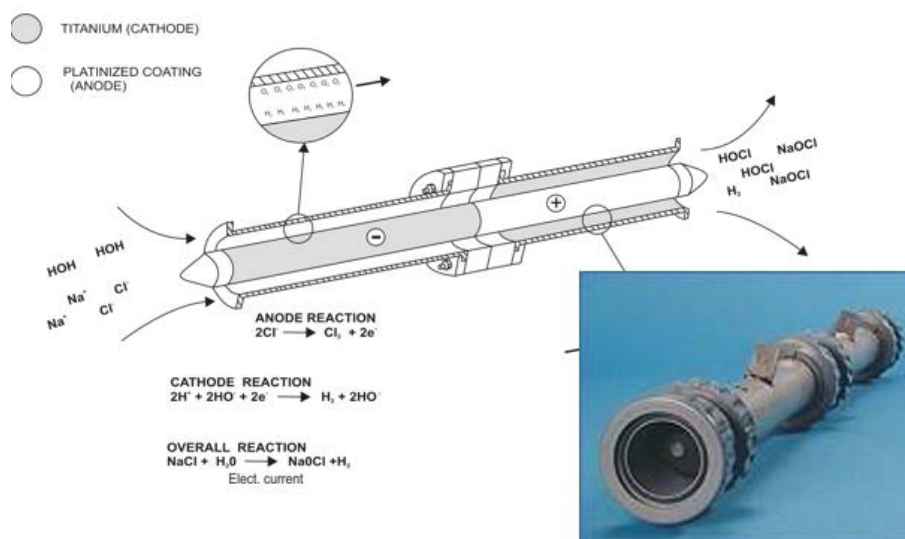


Figure 3.6: Sodium Hypochlorite generator [19]

The amount of produced NaOCl is directly proportional to the D.C. current that have been applied. Diluted hypochlorite solution (OCI) will be transferred to a storage tank. This tank serves three purpose.

1. Removal of H₂ gas. Because produced H₂ gas during electrolysis process is a byproduct. The sodium hypochlorite solution and H₂ gas are passed through a gas water separator to separate the H₂ gas. Finally, for safety reasons and to reduce the explosion hazard, hydrogen gas will be diluted (lower than flammability point) and then vented to a safe location using air blowers.
2. The storage of NaOCl provides a reservoir that can help in running the process for a period, in the case of power cut.
3. Magnesium hydroxide (MgOH) removal. The other by-product of electro chlorination process is precipitation of MgOH from seawater. This is happened when the sodium hypochlorite is generated at high enough concentration. In this case, the pH of the water will rise sufficiently and MgOH precipitated. Precipitation of MgOH should be removed before injection into the pumps, otherwise blockage may occur. It should be note that the storage tank is designed large enough and allows the MgOH settles at the bottom of the tank and then will be removed via suction lines. [19]

Hypochlorite from the storage tank will be dosed into the process system to enable disinfection to take place Figure 3.7

The cleaning process for the electro chlorination unit can contain an automatic and on line backwash system via a rotating backwash arm. This backwash system can remove the solids build up from the system.

In addition to hypochlorite, other, liquid, chemical biocides will be dosed into the system in order to provide a better control of bacterial growth.

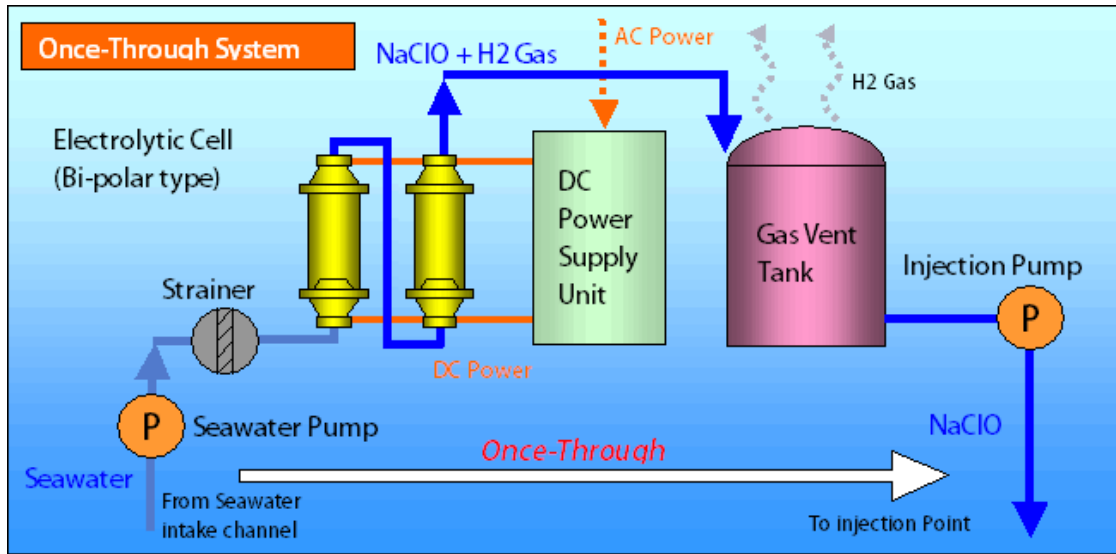


Figure 3.7: Sodium Hypochlorite Generation Process [Courtesy of Mitsubishi ECE]

3.3.4. Fine Filtration

Seawater contains various types of particles with different sizes. Most part of particles should be removed from seawater in order to increase the permeability of the water into the formation. Therefore, in addition to coarse filters other filter packages such as four fine filters (dual media filters) should be installed for removal of smaller particles. The fine filters are usually designed to remove 80-90% of the particles with a diameter of 2-5 μm . the fine filters are the main point of filtration and are fully automatic in operation. When the fine filters are in operation, the coarse filtrated seawater enters to the filters and evenly distributed to each filters media via an internal distribution system. Control system for sharing the water to the filters media is based on gravity force and grain size in a down flow patter. The four different composition of filter media are listed Table 3.1.

Table 3.1: shows four different layers of filter media based on their depth, density and particle size [24].

Filters	Depth (m)	Density (kg/m^3)	Particle size (mm)
Anthracite ⁵	0.38	817	0.6-0.8
Fine Garnet ⁶	0.38	2085	0.37
Coarse Garnet	0.23	2240	1.6

Media filters are usually 'downflow' and contain several layers of filter media. Anthracite and fine garnet layers do the majority of the solids removal (with externally dosed filter aid chemicals) while coarse garnet (and sometimes pea gravel) is used to ensure even flow distribution through the filter bed area. A collector system consists a series of spirally wound wedge wire tubes and is connected to a single outlet line.[19]

⁵ Anthracite: A type of coal

⁶ Garnet: A hard Crystal sand

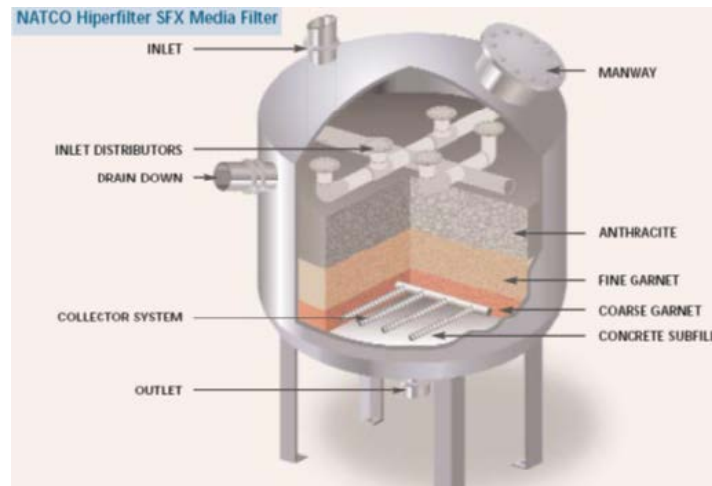


Figure 3.8: Fine Filter [19]

In order to enhance the performance of the filters, various chemicals are dosed to the water as filter aids. Polyelectrolyte and coagulation chemicals are two chemical aids that are typically dosed immediately after seawater intake upstream of the filters. These chemicals have high adsorption properties and absorb to the surface of fine suspended particles, coagulating them into large ones so that they can be easily removed. [22]

After a period of operation, the amount of particles collected in the filters and cause the differential pressure to increase. Filter cleaning is therefore required. In the cleaning process (backwashing) reverse flow and air scrubbing using an air blower is utilised. Each filter must be taken out of the service and put in cleaning mode for a period. During this time, the other filters must be capable to maintain the required injection rate during backwash sequence and the backwash flow required by the filter to be cleaned. Air blowers are used to agitate the media and help to remove particle from the filters in reverse flow mode. [19] [23]

Media filters are well known as an inexpensive filtration method, but have relatively high operating costs due to chemical dosing, media loss and failures accordance to backwashing process (e.g. valve failure). Therefore, the industry is gradually moving away from media filtration towards alternative membrane type technology.[24]

3.3.5. Deaeration

To enable the use of cheaper materials in water injection manifolds, long HP seawater injection pipelines and injection wells it is common to use a deaerator tower to remove the dissolved oxygen from the seawater. The reason for removal of dissolved oxygen is purely related to one of corrosion prevention and not a requirement within the reservoir for increased recovery.

In previous chapter, it was described that seawater contains dissolved oxygen (e.g. 9 ppm) and it should be removed (typically down to 10 ppb levels) from the seawater before entering a carbon steel pipework system which transports it to the reservoir. Vacuum deaeration and gas stripping are the two main standard methods, which are applied by operator companies to remove dissolved oxygen from seawater and thus overcome the corrosion issues. [20] [25]

Gas stripping Tower

In gas stripping tower, the water flows into to the tower from the top and the free oxygen in seawater is removed by injecting a stripping gas from the bottom. The counterflow of gas used inside the tower, is usually a fuel gas (although nitrogen is an alternative which requires regeneration of the nitrogen). In the case of fuel gas, the stripping gas will be flared and CO₂ will be emitted into the air [19] [24]. The emission of CO₂ is not desirable from environmental authorities, due to the air pollution and long-term toxic effect in human's body and animals (e.g. polar bears). Therefore, many debates about impacts and emission of CO₂ (e.g. global warming) have been conducted in Norway and other regions around the world.

Vacuum Tower

In vacuum tower, the partial pressure of oxygen reduces by creating a vacuum inside the tower via 2 or 3 stages of powerful vacuum pumping. The pressure is reduced until the water 'boils' inside the tower [19] Figure 3.9

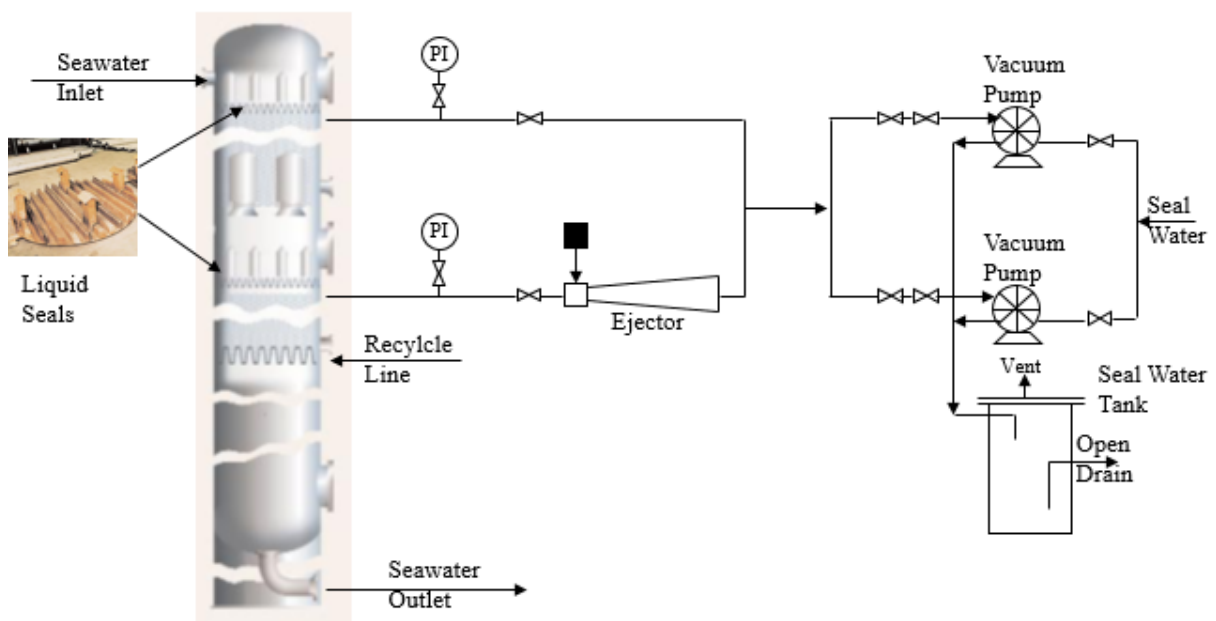


Figure 3.9: Vacuum Tower [19]

The experience and results have shown that the vacuum tower alone can reduce the concentration of dissolved oxygen in seawater to approximately 50 ppb. Therefore, to reduce oxygen to the required injection dosage levels of 10 ppb, chemicals such as oxygen scavenger (chemical stripping) are required. To ensure an effective deaeration system, other chemicals that are injected into a typical vacuum deaerator are antifoam (to enable different stages of vacuum to be maintained) and biocides (to remove build-up of biofilms).

Experience shows that conventional technologies such as gas stripping/ vacuum deaeration in combination with the required chemical injection, occupies lots of space on production platforms and installation of such a heavy and large systems are difficult. Therefore, various suppliers have been developed newer and more compact technologies

(e.g. Seaject and Minox Deaeration systems) that offered less weight and more space on topside. [19]



Figure 3.10: Minox™ Deoxygenation [19]

Table 3.2 summarized various deaeration technologies that are used by operators companies for oxygen removal reason.

Table 3.2: Oxygen removal technologies [24]

Technology	Advantages	Disadvantages
Gas stripping Tower	Well proven and reliable	<ol style="list-style-type: none"> 1. Very heavy 2. Fuel gas consumption 3. CO₂ discharge 4. Fouling by suspended 5. solids and biological growth 6. Requires chemical injection
Vacuum Tower	Wellproven and reliable	<ol style="list-style-type: none"> 1. Very high 2. Very heavy 3. Significant power consumption (Vacuum Pump) 4. Fouling by suspended 5. solids and biological growth 6. Requires chemical injection
Minox ⁷	<ol style="list-style-type: none"> 1. Compact Significant saving on space and weight. 2. Produces < 5 ppb without oxygen scavenger 	<ol style="list-style-type: none"> 1. Nitrogen stripping gas requires regeneration 2. Could increase reservoir souring due to carry over of methanol 3. More complex than stripping towers 4. Requires chemical injection (antifoam) 5. Poor operational history

⁷ Minox : Originally developed by Norsk Hydro and installed at Snorre A and Statfjord C.

Seaject⁸	<ol style="list-style-type: none"> 1.Compact Significant saving on space and weight. 2.No oxygen scavenger 3.Reduces O₂ < 10 ppb 	<ol style="list-style-type: none"> 1.Hydrogen stripping gas requires regeneration 2.Expensive palladium catalyst required 3.Complex technology 4.No significant operational history
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3.3.6. Cartridge Filter

Cartridge filters are design to remove any residual particles from treated seawater before injection into the wells and typically used for two following purposes:-

- As a backup filter (Guard filter) - in case of failure of the upstream fine filters.
- As a polishing duty – to remove particles of a smaller size than is possible by using fine filters.

Disposable cartridge filters or regenerable cartridge filters are commonly used for these purposes in offshore platforms. Cartridge filters should be changed when they become contaminated; operating cost for this filter is high. For example, a typical sign for replacement of the filter is increase in pressure drop across the filters and possible reduction of permeate flow. Disposal of used cartridge elements can also lead to environmental issues – particularly if the elements are to be burnt

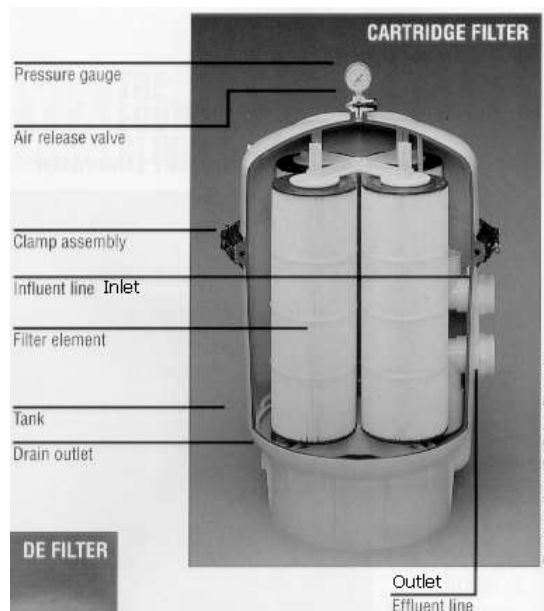


Figure 3.11: Cartridge Filter [Courtesy Wikipedia]

⁸ Seject^R: is a patented process, tested by Shell in Gulf of Mexico

3.3.7. Booster Pump

Negative pressure deaerated seawater from deaeration system requires boosting by booster pumps to enable it to be fed to the high pressure Water Injection Pumps. The booster pumps are either horizontal or vertical form and will be specified based on field requirement. The typical discharge pressure from a booster pump is 14 barg. [19]

3.3.8. High Pressure Water Injection Pumps

Once the booster pumps have provided sufficient pressure (NPSH), High Pressure Seawater Injection Pumps raise the seawater pressure to that required by the highest pressure water injection well. The level of the pressure to the remaining wells is adjusted downwards over individual choke valves according to the well and reservoir conditions for that particular injector. High Pressure Seawater Injection Pumps (HPI) consume a lot of power and can either be electrically driven or driven by gas turbines. [26]

3.4. Chemicals Injection

In addition to mechanical / physical treatment equipment listed above, the assistance of chemicals to assist the overall treatment process are required.

Chemical treatment packages, their responsibilities and their importance in achieving required water quality and protecting the reservoir from issues associated to microbiological activities are the themes that will be discussed in the coming sections.

Common types of chemicals used on topside seawater injection system are listed below:-

- Sodium hypochlorite
- Antifoam
- Filter Aids
- Oxygen Scavenger
- Biocides
- Nitrate
- Corrosion Inhibitor
- Scale Inhibitor

Each of these chemicals are transported from the chemical manufacturer to the operators supply base in chemical tote tanks (e.g. 3m³ storage tanks). The tote tanks are then transferred to supply boats and shipped to the offshore installation. The Tote tanks are then offloaded to the platform and stored in a suitable location. When required, the chemicals themselves are transferred from the tote tank to a local storage tank on a chemical injection and pump skid. The local storage tanks are used as a supply source for dosing pumps and then chemicals are dosed at a required dosage rate by injection pumps. Depending on the dose rate or the lifetime of the particular chemical, the frequency of the tote tank replacement (weekly / monthly) is organised. [28]

Table 3.3 illustrates a typical injection rates for various injection chemicals. Dosage rate are based on water treatment system by “Nalco Water Treatment system and Service Company”.

Table 3.3: Chemical dosage rate system

Process	Chemical	Use	Typical Injection Rate
Seawater Injection	Sodium Hypochlorite	Bactericide	As required to give residual of 0.5-0.8 ppm
	Coagulants	Filter Aid	2-10 ppm when is required as a dilute solution
	Silicones Antifoam	Antifoam	2-10 ppm when is required as a dilute solution
	Glutaraldehyde/ Quarternary Blend	Biocide	Batch dosage of 400 -4000 ppm biocide for 3 hours twice per week
	Phosphate Salt	Scale Inhibitor	5-30 ppm continuous dosed, when is required
	Imidozaline	Corrosion inhibitor	5-30 ppm continuous dosage, when is required
	Sodium Bisulphate	Oxygen Scavenger	As required to give < 5 ppb O ₂ , 15-30 ppm continuous dosed

3.4.1. Bactericide

Seawater provides an excellent environment for growing all types of bacteria and should be disinfected in order to avoid growth of bacteria. The main reasons for seawater disinfection is to prevent reproduction of aerobic bacteria (e.g. GAB) and anaerobic bacteria (e.g. SRB). These bacteria form either slime or foul and cause reservoir damages or produce H₂S, which in turn causes corrosion of carbon steels and other equipment.

Chlorine is used globally for disinfection for water. The oil and gas industry uses this chemical as a primary method to control growth of bacteria. Chlorination is available in liquid, powder or granules forms and sodium hypochlorite solution in the market. Since, chlorine in liquid form is very toxic, care must be taken in all level form transportation, storage to handling and dosage. In order to reduce the hazardous and risks, many offshore seawater treating facilities are using sodium hypochlorite solution by installation of on-board hypochlorite generators and generates sodium hypochlorite directly from seawater.[29]

On-site hypochlorite generators will be operated by piping seawater from vessel through generation cells and a D.C. current is passes through the water.

Dosage system

Dosage requirement for sodium hypochlorite injection into the system are adjusted based on the water flow rate into the system by a pump. There are always 2 two positive displacement pumps in the system for continuous dosing of NaOCl, but only one has responsible for hypochlorite dosage and the other one is used as backup in the case of failures. Chlorine takes time for a thorough disinfection reaction to take place. However,

there is only a limited amount of time available for the chlorines oxidation reaction to take place - i.e. from the injection point at the lift pump caisson to the deaerator where chlorine is removed by the reaction with oxygen scavenger. Therefore a typical injection policy for hypochlorite is to overdose in order to give between 0, 5 – 0, 8 ppm of residual chlorine⁹. [27]

In seawater treatment system for chlorination of water by sodium hypochlorite in addition to residual chlorine, some other terminology such as chlorine demand¹⁰ and chlorine requirement¹¹ also will be used.

3.4.1.1. DC Power for sodium hypochlorite generation

In order to convert power to D.C, different types of rectifier units used in sodium hypochlorite generation on topside. Rectifiers contain sufficient capacity to drive the conversion reaction. Figure 3.12 illustrates three types of rectifier units.

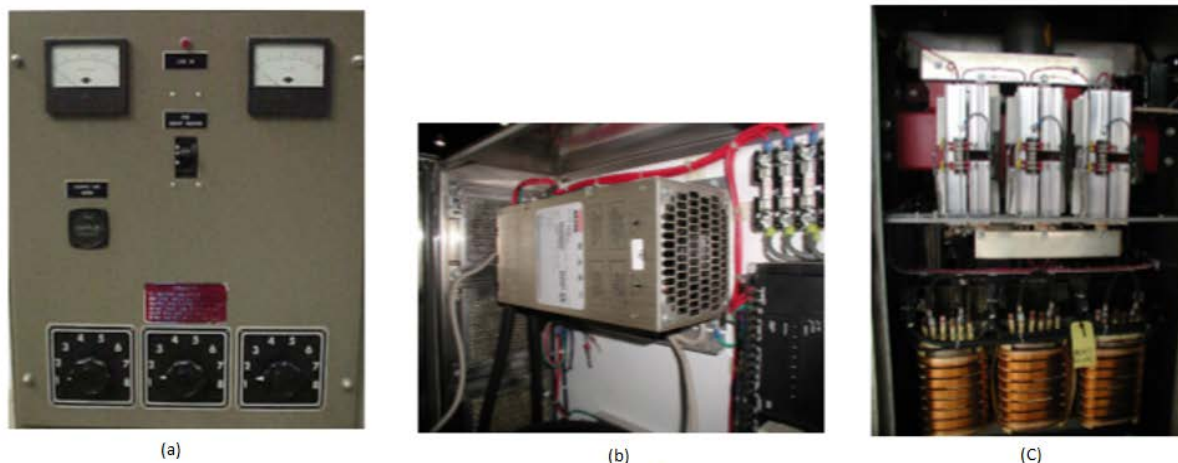


Figure 3.12: (a) Tap Switch Voltage Control, (b) Switching Power Rectifier, (c) Thyristor Rectifier [27]

Regular cleaning and maintenance are essential for every electrochlorinator unit. The reason is that calcarous material in water results in scaling deposits (e.g. calcium carbonate (CaCO_3) and magnesium carbonate (MgCH_2O_3)). Experience has shown that acids can solve easily these deposits. Therefore, most electrolysis systems are equipped with an acid cleaning unit.[27]

⁹ Residual Chlorine: Residual chlorine means the amount of chlorine available in the plant at any given time through the total process.

¹⁰ Chlorine demand: the reaction of chlorine with materials and chemicals in a water injection system.

¹¹ Chlorine requirement: the amount of chlorine, which is required to kill bacteria and to achieve residual chlorine levels in the plant. [20]

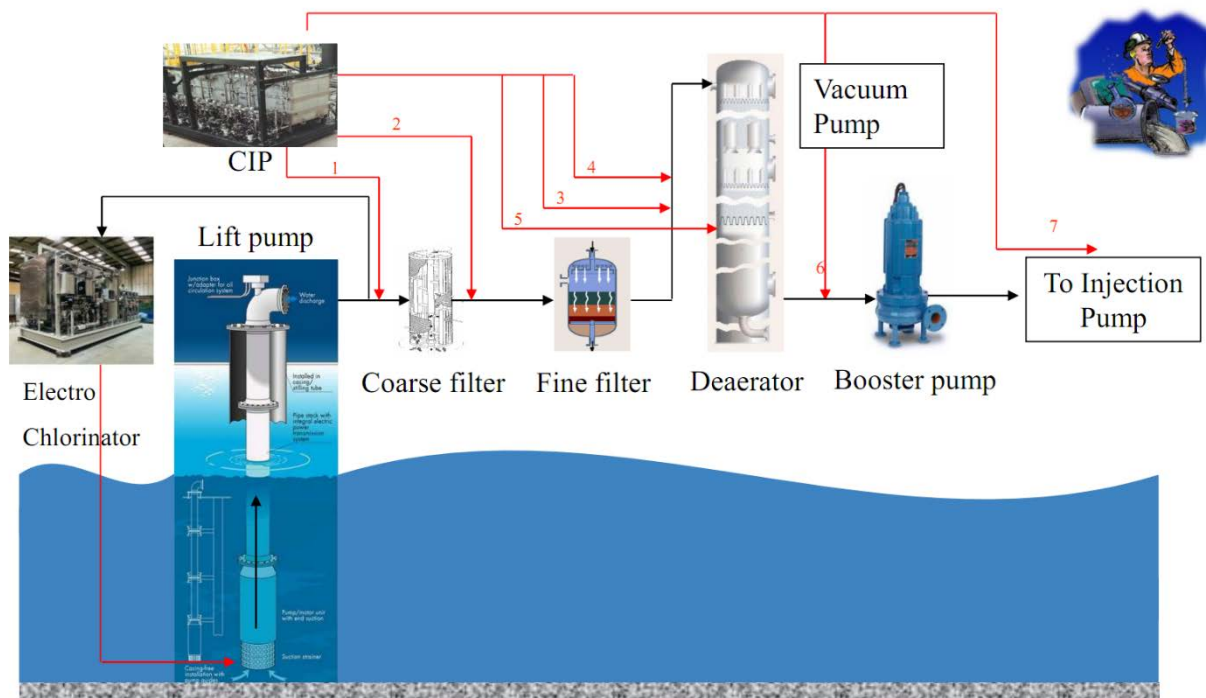


Figure 3.13: Chemical Dosage Points [19]

3.4.2. Filter Aids

Following the chlorination process, seawater enters to filtration units for particle removal. In order to achieve the desired performance of filtration, chemical aids are required. Two chemical types such as coagulant and polyelectrolytes (Filter aids) will be dosed into the main supply line upstream of media filters. Dosage will be made at a point which chemicals and water are mixed prior sharing in various filter lines [30]. Figure 3.13, lines (1 & 2).

Coagulant

Once coagulant is added to water, free particles in water will change their surface charges and stick together to form a larger one (floc). This mechanism is known as coagulation process. Coagulant chemicals are either metallic salts or polymers. Large particles become trapped on the filter bed and removed from the system during coagulation process. Table 3.4 shows typical coagulant that will be used on topside WI treatment system.

Table 3.4: Various types of coagulant.[30]

Chemical	Chemical Formula	Comment
Ferric Chloride	$\text{FeCl}_3 \cdot 7 \text{H}_2\text{O}$	-
Ferric Sulphate	$\text{Fe}_2(\text{SO}_4)_3 \cdot 7 \text{H}_2\text{O}$	-
Aluminium Sulphate	$\text{Al}_2(\text{SO}_4)_3 \cdot 14 \text{H}_2\text{O}$	One of the earliest and most extensively used chemicals

Dosage System

Metallic Coagulants should be injected neat into the system at a typical dosage rate from 2-10 ppm when it is required. The point for dosage with high injection pumps should be selected as far upstream as possible to maximize the contact and mixing time.

Polyelectrolyte

Polymers are made of long chain small organic carbon compounds and can be either cationic, anionic or non-ionic. Polyelectrolyte is a cationic (positive charge) flocculant aid and are added following coagulants dosing to increase the size of the flocs in water and neutralize the charge on suspended particles. [31]

Polyelectrolyte, which is assisting the filtration process are typically made of polyamide with different MW (molecular weight). Typical dosage is from 0.5- 2 ppm as a dilute form solution. Figure 3.14 illustrates a schematic of cationic polyelectrolyte mechanism.

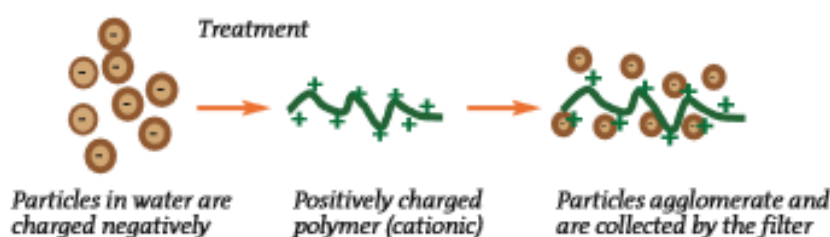


Figure 3.14: Filter Aid Mechanism [Adapted from MI-SWACO Production Chemical Handbook]

3.4.3. Antifoam

In the operation of petroleum processes, foaming has been recognized as an undesirable feature. Because it creates serious problems it should be controlled. There are several solutions in order to control foam and the core of all methods is to prevent or disrupt foam stabilization.

Vacuum towers in seawater injection systems have a high tendency to foam. Factors like mechanical processes, pressure gradient drop and turbulent motions have effects on foam formation. In addition to all factors above, contaminations in seawater can increase foam problems. Chemical dosage upstream of deaeration tower can be expected to prevent foaming. [32]

Dosage System

Prior to the foam forming, a dilute water- soluble antifoam (hydrophilic antifoam) will dosed continually into the deaeration tower with a dosage rate from 2-10 ppm. Figure 3.13, line 4.

Polydimethyl siloxanes (C_2H_6OSi)_n and fluorosilicones are two typical types of antifoams. Silicon is backbone for antifoam structures, because chemical structure of silicone's are such that they have low surface and interfacial tension. This property enables antifoam moves easily over the foam film, covers and finally collapses it. [33]

3.4.4. Oxygen Scavenger

A Vacuum tower alone can only reduce oxygen content of seawater down to 50 ppb. Therefore, in addition to the mechanical process, chemical injection is needed in order to scavenge remaining oxygen down to below 10 ppm level.

Oxygen scavenging chemicals consists of sodium sulphites or ammonium bisulphites. In some cases, cobalt salt can be used as catalyst to increase the rate of the reaction. Cobalt salt always will be added directly to sodium bisulphite as the part of the product. However, Ammonium bisulphate is not compatible with catalyst salts and catalyst salt must be added separately in order to reduce the risk of system failures.[35]

Equations (1) and (2) illustrate the scavenging reaction of ammonium bisulphite and sodium bisulphite.



Temperature, pH, catalysts (e.g. cobalt or nickel metal ions) and time, are factors that have effect on reactions.

Dosage System

Based on dissolved oxygen measurement, chemicals will continuously be dosed into deaeration tower in ranges between 15-30 ppm. [34], Figure 3.13, line 5.

The bottom of the deaeration tower contains a residence section. Seawater and oxygen scavenger chemicals are held in this section for approximately 3 minutes, in order to provide the required time for reduction of dissolved oxygen in water. Resistance section in vacuum tower also provides a volume of water, which is used for running down time on booster and injection pumps. [19]

3.4.5. Biocide

In previous sections, microbial control was mentioned as a necessary process in order to avoid bacterial growth and multiplies them on equipment (e.g. pipeline) or within the reservoir. Common problems such as biofouling, MIC and reservoir souring were most undesired and demands for effective solutions are very high from oil and gas industry.

Since seawater contains all necessary conditions for living, reproduction, growing and activities (e.g. plenty of bacterial nutrient (food), high sulphate content and relatively high temperature) is an excellent medium for bacterial activities [36]. In seawater treatment system, chlorination was the first step for killing undesired bacteria (primary biocide treatment). This is not enough to control biological activities all the way down to the reservoir. Because, chlorine (residual chlorine) in the system will gradually be removed mechanically in deaerator tower or chemically by oxygen scavenger chemicals. This leads to poor microbial control and resulting lost production time, poor crude oil quality and pipeline

failures. Biocide is a very strong disinfectant chemical and will be used as secondary sterilization method in seawater treatment to fight with bacteria.[39]

Types of biocide

Three types of biocide are available in the market and they will be used in water treatment based on their action with other components find in water.[37]

1. Electrophilic Biocide

Electrophilic biocides (electron friendly) react with electron groups of chemicals and causing cell death. Glutaraldehyde (GA) is the most common types of aldehyde based biocide and using in water injection system. GA able to control anaerobic sulphate reducing bacteria in oil wells.

2. Lytic Biocide/ Membrane active

The biological activity of bacteria reduces by exposure to lytic biocides. Quaternary ammonium and quaternary phosphonium based biocides are two broad groups of membrane active biocides. Once these biocides dosed to the system, due to the amphiphilic structure reacts with bacteria's cell and disrupter cells membrane.

It should be note that ammonium biocides have a surfactant or foam formation property on process equipment and react with anionic additives in an undesired way under dosage. Therefore, this biocide should be dosed when injection is stopped for a short period or under closely controlled operational circumstances.

Quaternary phosphonium biocide in comparison with ammonium biocide has less surfactant property, react faster against microorganism and highly effective for removal of biofouls. [38]

3. Blends of Biocides

In order to obtain more action against bacteria and algae, mix biocides have tried in oil and gas industries. The result related to combination of biocides were very successful to kill more bacteria. Formaldehyde/ Glutaraldehyde mixture and Aldehyde/ quaternary amines mixtures are two common types of blends biocides.

Dosage System

Biocides are usually dosed, either in, or downstream of the deaeration tower in order to eliminate the problem caused by the new found anaerobic conditions (oxygen free environment) which give the remaining sulphate reducing bacteria a suitable environment to reproduce. Figure 3.13, line 3, 5 & 6 are all places where biocide is normally injected- (depending on operator and their chosen dosing philosophy). Usually biocide will be shock dosed to the system. This means that for instance, GA will typically be shock dosed at 400 – 4000 ppm dosage rate for 30 mins- 3 hours at regular intervals (e.g. daily - twice per week).

3.4.6. Scale Inhibitors

Injection of scale inhibitor is a logistical and successful solution for scale prevention that the offshore industry has been using for many years. Scale inhibitors are usually injected at

the well head just before injection water flows into the reservoir [19] [45]. Figure 3.13, line 7.



Figure 3.15: Scale Formation [Courtesy of Wikipedia]

Dosage System

Based on scale formation (e.g. calcium carbonate, barium sulphate or calcium carbonate), the selected scale inhibitor will be continually dosed with rate between 5-30 (ppm) in order to create a buffer zone of inhibited water in the formation away from the wellbore.

3.4.6.1. Classification and the type of scale inhibitors

Scale inhibitors are classified as organic and inorganic. Quality of water and type of the scale have key roles in selection of specific scale inhibitor. For example, southern region of North Sea contains high level of sulphate (SO_4^{2-}) and salinity of water is high, but central part of the North Sea contains less Barium (Ba^+) and pH 4,4. Therefore, different parts of North Sea require different scale inhibitors, in order to manage scale formation. [46] [48]

Phosphate, such as poly metaphosphate or phosphate salts are known as inorganic inhibitors. These are very effective inhibitors against both carbonate and sulphate scale in low temperatures [46].

Organic scale inhibitors contains phosphonate and will be dosed as phosphonate polyacrylic acid (PAA), phosphinocarboxylic acid, sulphonate polymer and phosphonate. Phosphonate ester is a typical organic scale inhibitor that is commonly used in water treatment system. Scale inhibitors with phosphonate structure are more temperature tolerant than phosphates and can be very effective against carbonate and sulphate scale in high temperatures. [47]

The other types of scale inhibitors that have been shown to be particularly useful against scale are polymeric compounds. Poly acrylic acid and polycarboxylate are two types of copolymer inhibitors that are very effective in seawater. [19]

3.4.7. Corrosion Inhibitor

The main objective of preventing corrosion is to prolong equipment lifetime and avoid unplanned downtime for equipment and pipework repair. From a safety perspective, it is also important to prevent unexpected equipment failure, which could prove to be hazardous to personnel and other system equipment. For water injection applications it is also essential

to avoid corrosion products plugging the injection wells, which requires very expensive work-overs.

While the material selection of water injection equipment is usually made on the basis of preventing corrosion, materials more prone to corrosion (e.g. carbon steel) are sometimes used for economic reasons – particularly where pressures are elevated and increased material thicknesses are required, (e.g. HP pipework downstream of injection pumps).

The potential of corrosion occurring has been eliminated as far as possible by removing the dissolved oxygen in the seawater. However the potential still remains, mainly from microbiological activity and therefore, corrosion inhibitor dosing is usually provided upstream of where the carbon steel pipework begins e.g. Figure 3.13, line 6.

Classification of Corrosion Inhibitor

Corrosion inhibitors are divided in many groups as organic and inorganic inhibitor, filming and non-filming inhibitors, cathodic and anodic inhibitors.

The majority of corrosion inhibitor in water treatment industry consists of organic amine (Imidozoline). These chemicals can adhere at the surface of the metal as film (Composite) and protects metal from direct contact with oxygen that is dissolved in water. [19] [38]

Dosage System

In order to provide the best protection ability, corrosion inhibitor dosage is very important item. Because, incorrect dosage rate resulting in one of the scenarios below.[38]

- When the corrosion inhibitor will be dosed less than the required level the protection film will not formed correctly and the metal surface will be corroded. (Under dosed)
- Dosage of inhibitor more than required level may cause the film to break away from the surface. This phenomena is like peeling of paint from surface, therefore, exposed areas become corrode very fast. (Overdosed)
- The worst scenario occurs when surface is naked and corrosion reaction will take place in a very short time. (No dosage)

Therefore, corrosion inhibitor initially will be dosed at high rate between 50-100 ppm to form the film on the metal surface and dosage rate will be reduced to 5-30 ppm on a continuous basis.[19]

Table 3.5: Summarized different chemicals, products and their effects in seawater treatment system.[49] [50]

Nalco Product Name	Generic Type	Purpose	Application	Types of Chemicals
NaOCl	Sodium Hypochloride	Control/Prevent the growth of marine organisms and bacteria	Typically is dosed upstream of SW lift pumps	Sodium Hypochloride
Biotreat	Biocide	Control/Prevent the growth of marine organisms and bacteria	Typically is dosed upstream of SW lift pumps	Gluteraldehyd Formaldehyde Phouphourous
Foamtreat	Antifoam	Control/prevent the formation of foam in deaeration tower. Aid in the release of the dissolved oxygen from the water	Typically is injected upstream of the vacuum tower	Poly dimethylsiloxanes Fluorosillicones
Scaletreat	Scale Inhibitor	Control/prevent scale formation	Typically injected into the water	Polymers Phosphonate Phosphonate Ester
Corrtreat	Corrosion Inhibitor	Control and avoid of corrosion products Plugging the injection wells Prevent equipment failure in the system	Typically injected downstream of the DA or booster pumps	Organic Amines Imidazolines Imines
Scavtreat	O₂ Scavenger	Remove trace amount of O ₂ and prevent the corrosion following vacuum tower	Typically is injected into the DA tower	Ammonium Bisulphite Sodium Bisulphite
Floctreat	Filter Aid	aid filtration in the form of Coagulant and Polyelectrolytes Filter aids are	Typically is injected upstream of the fine filters	Coagulant Ferric chloride Ferric sulphate Aluminium sulphate Polyelectrolytes Polyamines

3.5. Sulphate Removal

The presence of sulphate ions in seawater is undesired and puts restrictions on operation facilities. In the Chapter 2, it was mentioned that seawater containing SO_4 (2,800 mg/l) and mixing of seawater with formation water within the well caused formation of an insoluble barium or strontium sulphate scale. In order to prevent formation of hard structure and insoluble sulphate scale and avoid enormous operational problems scale inhibitor treatment (e.g. Squeeze treatment) is sometimes required. [24]

Conventional “squeeze” treatment may provide a workable solution but the technique does have some drawbacks:

- Squeeze treatment needs repetition
- High operating costs
- Sometimes squeeze is ineffective in removal of the crystals formation on surfaces of metals and deep in reservoir, therefore it could not always be reliable.
- From HSE point of view, using of high amount of chemicals and handling of them need a far reaching safety program and follow up.

Removal of sulphate ion (SO_4^{2-}) from seawater for injection purpose using “Sulphate Removal Technology” (SRP) was investigated by oil companies and has reached more effective results in comparison with chemical squeeze treatment. Marathon oil was the first company that installed a sulphate removal package at Brae platform in North Sea in 1988. Agip followed with sulphate removal package installation on Tiffany and Toni fields. [24]

Currently, there are many other platforms and ships in North Sea and other offshore locations around the world, that use SRP to reduce the level of sulphate ions in water for both scale control inside the equipment and more control over souring of reservoir. Although this technology is very efficient from different aspects, it has its challenges such as size, operation cost, and high-energy demand. In addition, CO_2 emissions into the air are increased due to the trans-membrane pressures required. [52]

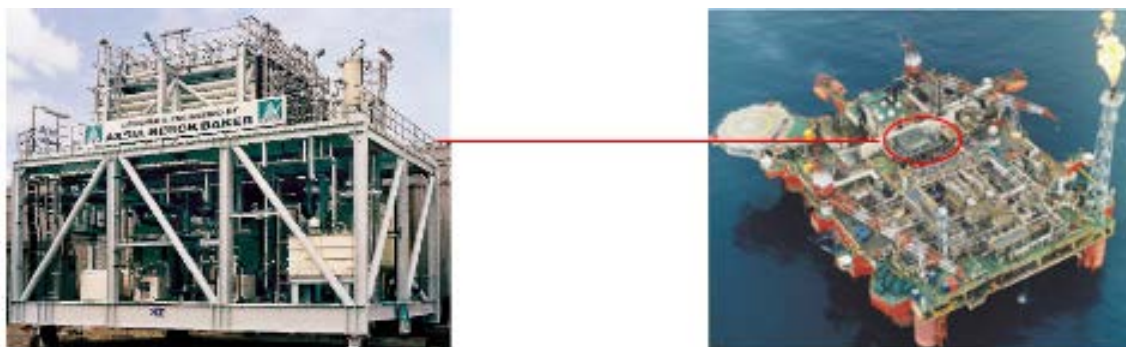


Figure 3.16: Sulphate Removal Plant on Platform [19]

3.5.1. Sulphate Removal Package (SRP) Concept

Sulphate removal can be conducted either upstream or downstream of a deaerator and there are pros and cons to both locations. However it is more normal for an SRP to be placed upstream of a deaerator.

SRP plants are equipped with nanofiltration membranes, which consists of two stages of nanofiltration vessels. With this arrangement, the seawater feed is introduced to the first array of membrane and approximately 50% of the feed passes through the membrane material with the sulphate being reject on the surface of the membrane. The 50% reject water is fed to the second array of membrane and more 50% is converted to product with a lower sulphate content. The two flows of low sulphate water are mixed to give a recovery of 75%. The remaining of 25% of increased sulphate reject being discharge to the sea with consideration to the environmental regulations and water with low sulphate content will transferred for other required treatments, Figure 3.17. [19] [51]

Pretreatment, cleaning and backwashing of membranes are necessary in order to avoid fouling, clogging and reduction of membrane lifetime. A cleaning program system is normally used to clean one bank of membrane vessels at a time.

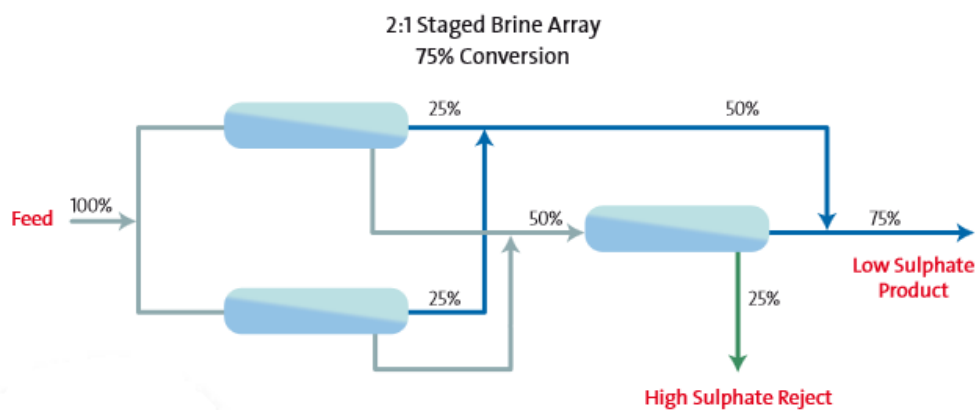


Figure 3.17: Sulphate Removal Flow Diagram [Courtesy of Veolia Water Solution and Technology]

3.6. Power Supply for Topsides

In the offshore oil and gas industry, most process equipment needs electrical power in one form or another. Therefore, in order to produce the required power, a strong energy producer such as a gas turbine is normally used. Gas turbines generate electrical power by burning fuel gas to produce rotational energy and using it to drive electrical generators. The most common types of aero derivative gas turbines generate ca. 24 MW of power. [72]

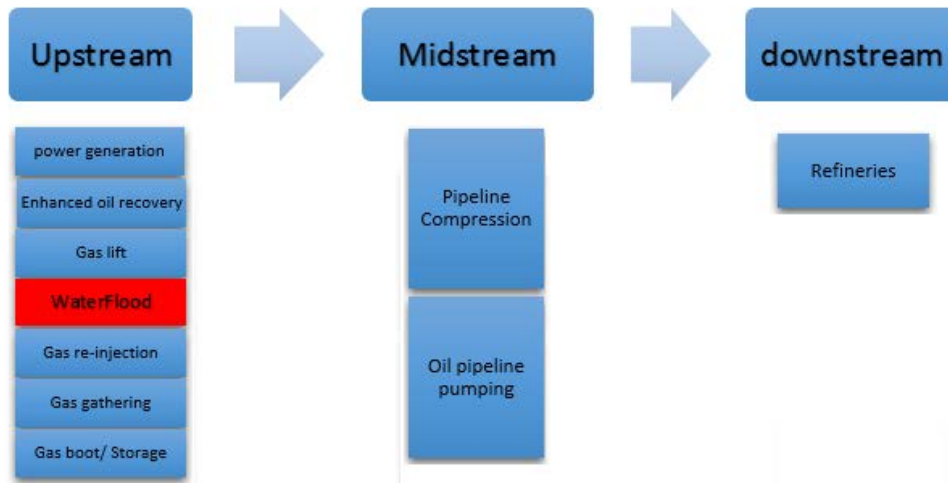


Figure 3.18: Offshore Application of Gas Turbine in Oil and Gas Industry

For waterflooding applications on a platform, the required power depends on WI duties. Various types of turbine in combination with gearboxes are used. The Power generation for waterflooding will vary depending on the water injection rate the treatment process and the injection pressure, but 15 MW systems are not uncommon. [71]

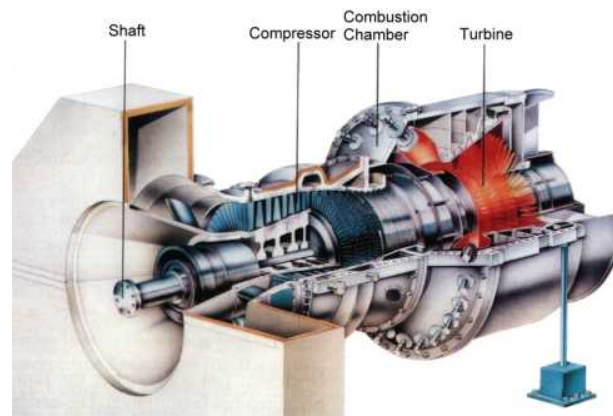


Figure 3.19: Gas Turbine [Courtesy of Wikipedia]

4. SUBSEA SEAWATER INTAKE AND TREATMENT SYSTEM

The demand in development and implementation of cost effective water treatment technologies that offers less impact on environment and increases support to get the oil out of the ground are becoming increasingly more sought after in the oil industry. Therefore, the need and ideas for a subsea seawater treatment system evolved from the restrictions encountered with a typical topsides treatment system and the process advantages that are found naturally on the seabed.

Raw Seawater Injection (RSI)

Injection of 'raw' seawater into the reservoir from the seabed by subsea installations have already been implemented by several companies including:-

Canadian Natural Resource (CNR) in UK continental shelf on Columba E field.

Statoil in the Norwegian Continental shelf on the Tyrihans field (also RSI from topsides pumps on the Norne Field)

Petrobras in the Brazilian continental shelf on the Marlim field.

However, the above field applications reflect fields that have 'special circumstances' where normal seawater treatment is not required. An example of this is the Tyrihans field where the injected water drives an aquifer that in turn drives the oil – i.e. the injected water does not meet the oil and give way to reservoir souring. These fields are therefore considered the exception rather than the norm. [9] [12] [13]

Seawater Intake and Treatment System (SWIT)

This chapter describes a new subsea seawater intake and treatment system which, following several years of development, is seen as an alternative to traditional topside seawater injection in all aspects of water treatment considered necessary for normal secondary recovery purposes. Figure 4.1 shows development phases of SWIT.

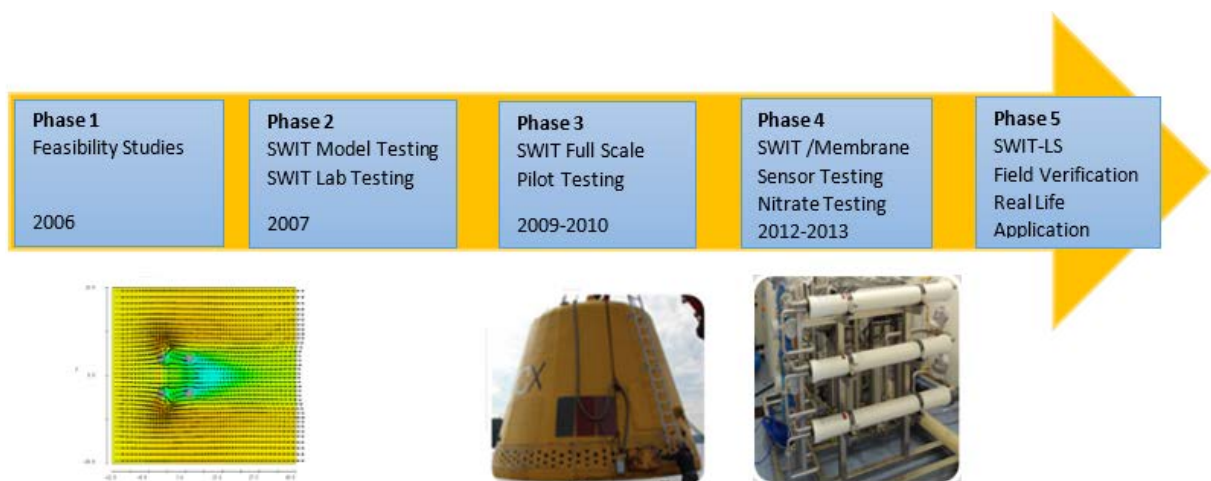


Figure 4.1: SWIT History Development

4.1. How the Subsea Water Intake and Treatment (SWIT) Process Works

As already discussed, water treatment is required to maximise reservoir sweep efficiency and protect the reservoir against unwanted biological activity that may cause it to go sour.

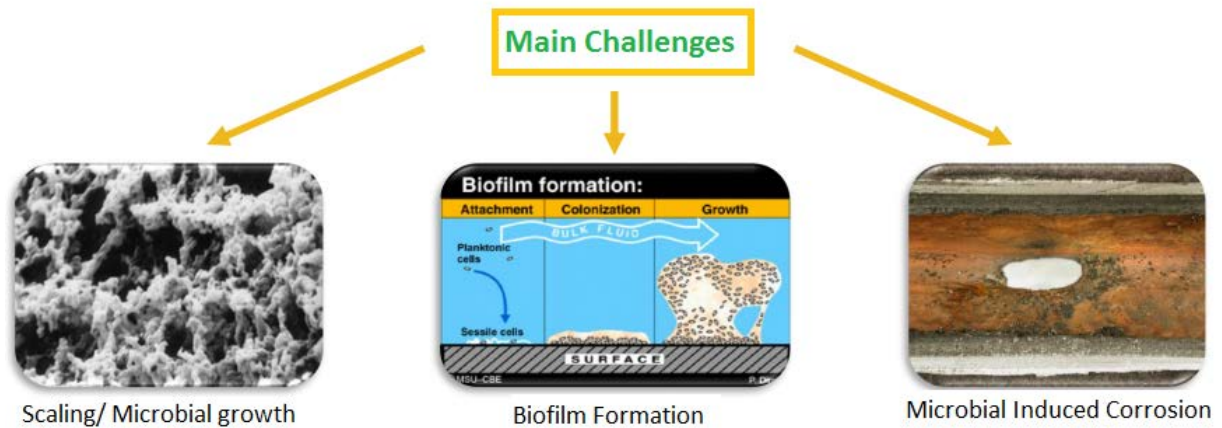


Figure 4.2: Main Operational Challenges of Seawater Injection [Courtesy of Seabox]

SWIT utilises seabed conditions and provides a simple and effective method of performing water treatment and feed seawater to one or more injection pumps. Under normal operation, there are no moving parts and water is simply sucked through a 'Still Room' on its way to the suction of an injection pump. On its path through the Still Room, the main treatment aspects of the SWIT system are: [58]

- Solid removal/ settlement
- Seawater disinfection (to avoid reservoir souring)
- Biocide shock dosing (optional) for injection 'system' sterilisation

4.1.1. Solids Removal

Normally raw seawater contains two types of solids - organic (e.g. plankton and plant life) and inorganic solids (e.g. sand, clay and silt) that are desirable to remove from injection water before entering into the reservoir. Filtration processes are mainly used for removal of solid particles on a topside treatment plant. However, filtration is often problematic due to the variation of the solids and solid loading in various times of the year. Therefore, having water treatment located on the seabed has several advantages over traditional methods. On the seabed – particularly at significant depths, the motion of water (current and waves) are typically lower for most times of the year. Seawater at depth will most likely have less organic and inorganic particles than seawater extracted from topside.

The key element for removal process by SWIT is a patented "Still Room". The function of "Still Room" is to provide a long residence time (ca. 1 hour) for the solid particles. Seawater enters SWIT through a screen into a Treatment Cartridge in higher portion of "Still Room". During the residence time, the solid particles that are denser than the water will drop out onto

tilted plates and be collected in solids collection basins at the base (Sand particles as small as 15 μ would be expected to be removed in this way).

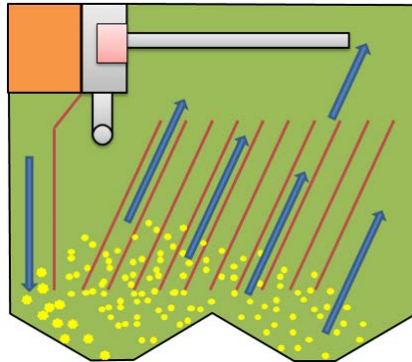
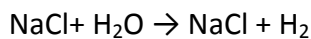


Figure 4.3: Solids Removal Process [Courtesy of Seabox]

4.1.2. Seawater Disinfection Process – Electrochlorination

Disinfection of seawater in SWIT is achieved via a two-stage electrolysis process designed to kill naturally occurring bacteria and organic matter.

The first stage comprises of electrochlorination of seawater (EC) includes for a long exposure time within the “Still Room”. The seawater passes through large electrochlorinator grids and accurate quantities of chlorine (OCl^-) are generated from the salt (NaCl) present in the seawater. The chlorine dosing and long residence time provides an effective kill rate of bacteria and larger organic matter. Larger ‘dead’ organic particles are also seen to drop out through the gravity settling process (Primary settling).



(1) (Electrochlorination)

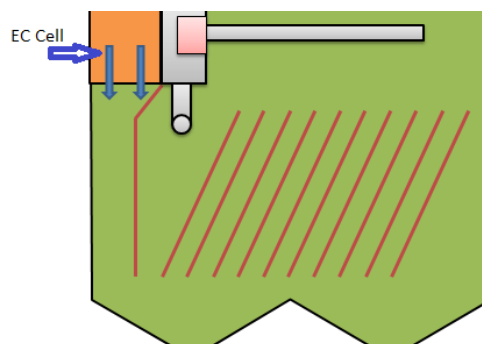
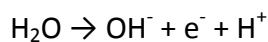


Figure 4.4: Electrochlorination Unit

4.1.3. Seawater Sterilization - Hydroxyl Radical Generation

At the exit of the system, seawater progresses through a Hydroxyl Radical Generator (HRG). HRG is a new and patented technique, which is the second and final oxidation process for disinfection and organic material mineralisation before leaving the SWIT unit. Seawater is then sucked from the system to the water injection pump.



(2) (Hydroxyl radical generation)

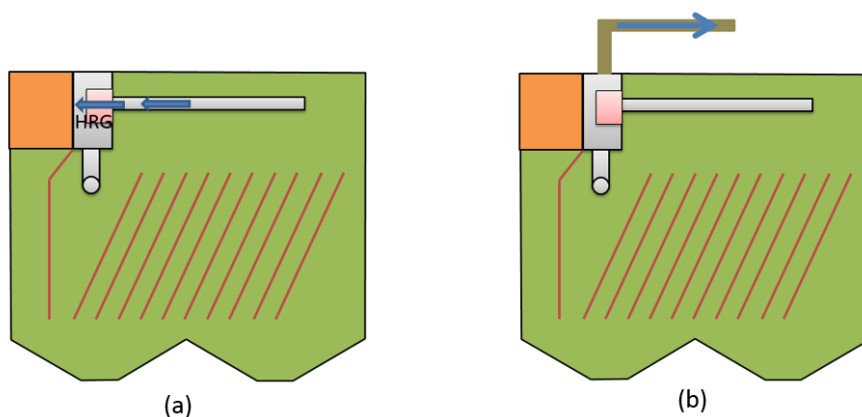


Figure 4.5: (a) Hydroxyl Radical Generation Unit, (b) Injection Process

The H^+ gas produced from HRG is a by-product and shall be vented from a roof of the “Still Room”.

Hydroxyl radical generation is a new technique in oil industry and has developed in a recent years as an environmentally friendly solution for sterilisation of ballast water discharges into the sea. The technique can protect against the proliferation of aquatic invasive species and it does not have any downstream toxicity. [26] [56]

In a previous section, it was mentioned that there is no need of biocide periodic shock dosing in SWIT treatment system in comparison with topside seawater treatment. The reason

was described presence of chlorine all the way to the reservoir. However, the facility for dosing of biocide can be designed into the system as a precaution.

4.1.4. System Disinfection - Biocide Injection

Chlorine dosing and soaking alone will ensure a significantly reduced rate of biofilm build up compared to a topside system. However, over a period, it is a possibility that biofilm may start to form in the system.

Periodic shock dosing of biocide can be used to destroy any biofilm that can build up in the well tubulars on the way to the perforations and in the near well bore area. However, the test results from full scale SWIT testing have shown that the required biocide shock dosing with the SWIT system will be a lot less frequent than with a topside system due to presence of chlorine and oxygen all the way to the reservoir. It should be noted that the facilities for dosing of several other types of chemicals (e.g. surfactant) could also be included in the design depending on the specific requirement for the injection well.

Biocide Injection

The biocide injection system basically consists of an accumulator and an automated valve. A topside chemical injection pump is used to transfer a single shock dose of biocide via the power umbilical to a subsea accumulator. This operation will be done on an ‘as required’ basis (e.g. once /month). When the accumulator contains the required amount of biocide, the accumulator charging from topside is stopped. A valve is then activated which opens and discharges biocide into the treated water discharge line between the SWIT and injection

pump at a much larger shock dose rate (e.g. 1000 ppm for 30 min). This periodic charging regime therefore avoids storage of significant quantities biocide on the seabed whilst allowing a significant shock dose to be achieved.

4.2. Advantages of Subsea Waterflooding

The treatment processes of water will take place at seabed and then feed directly into injection pumps at the subsea wellhead and then onto the injection wells. The treatment system utilises new technologies combined with existing ones to treat seawater and gives the operators flexibility and significant benefits in many aspects. [54]

- Less weight and area capacity required on topside
- No long reach platform water injector required
- Increased recovery of oil from the reservoir and protect the reservoir against unwanted biological activity
- Less energy is required per barrel water injection (lower emission of CO₂)
- Very low chemical usage, if its required (from HSE views that means less impact of chemicals to environment and lower risk related to offshore personnel)

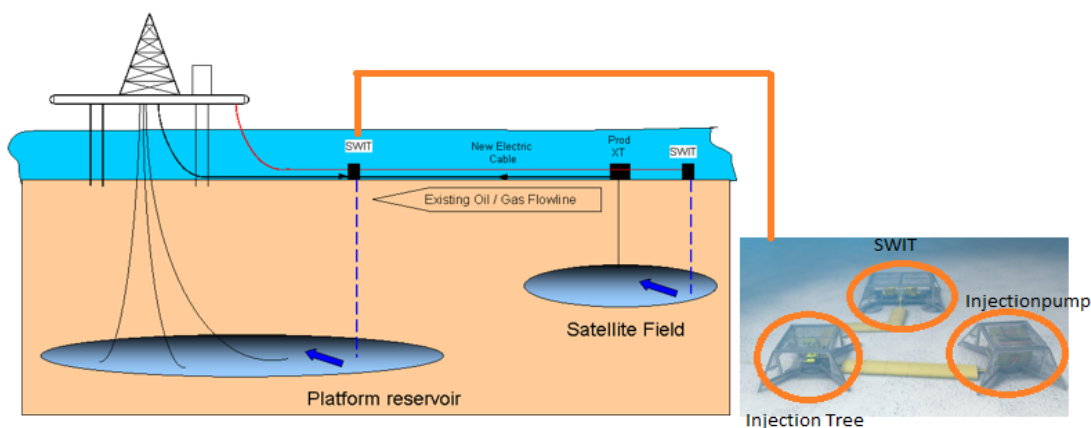


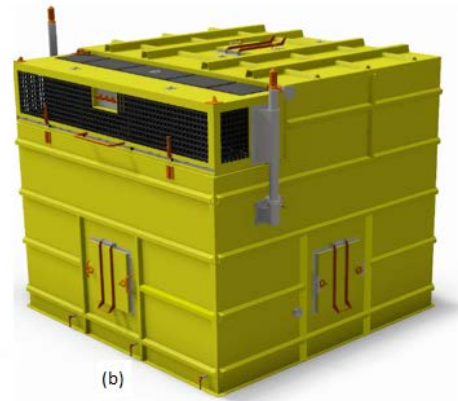
Figure 4.6: Subsea Seawater Intake and Treatment system [Courtesy of Seabox]

Based on SWIT development history illustrated in Figure 4.1, a cone shaped still room was designed and installed on the seabed of Oslo fjord for pilot testing in 2009 (phase 3). The results from full scale pilot testing have shown significant results in achieved level of sediment settling and disinfection of the water. [58]

However, Based on feedback from clients and requirements for larger treatment capacity, Seabox AS found that the pilot test design should be developed further into an industry version in order to fulfil all relevant industry standards and requirements. Therefore, a new design of “Still room” for industrialization project was created. This “Still Room” is designed for permanent subsea installation with design life of 20 years minimum. Treatment Unit (part of the still room) is to be retrieved every 4-5 years for operation and maintenance.



(a)

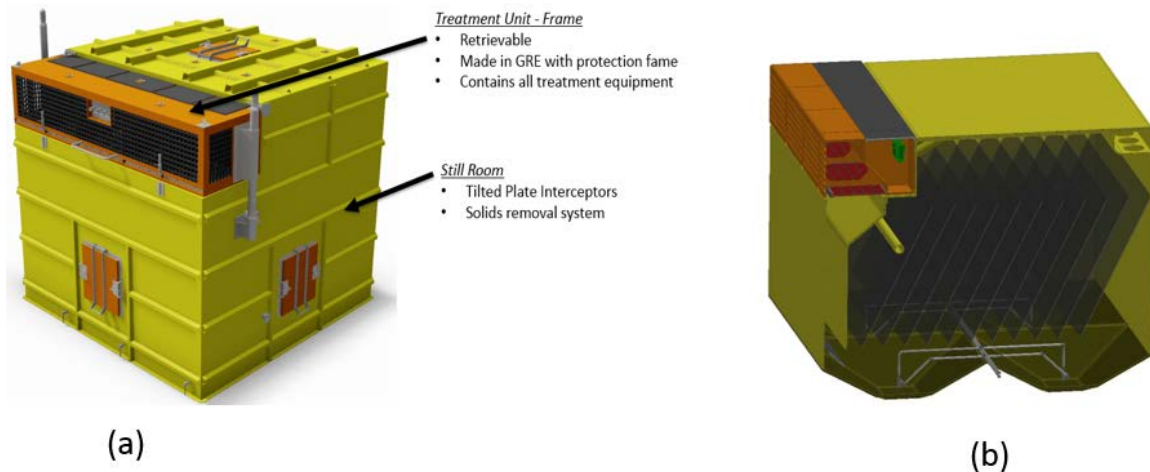


(b)

Figure 4.7: (a) SWIT Pilot Testing Design (b) SWIT Industrialization Design [Courtesy of Seabox]

4.3. Still Room

A SWIT treatment unit is designed to disinfect and to remove inorganic particles from the raw seawater using a “still room” technique. Solid settling within the still room and provision of residence time to allow total chlorine reaction to take place are key to the SWIT treatment process. “Still room” is also used for protection of the internal devices from the external environment (e.g. current, tidal in the sea). Figure 4.8 illustrates Still Room design of SWIT. The treated seawater will be pumped into the reservoir via injection pump(s) and well(s).



(a)

(b)

Figure 4.8: (a) Still Room, (b) SWIT From Inside [Courtesy of Seabox]

4.4. SWIT Power and Control System

SWIT operation is designed to be all electric in operation. One of the areas where the SWIT water treatment system contains significant levels of innovation is the SWIT’s power system. There is no moving parts for SWIT and the connection between SWIT and topside will be provided via electrical cables. This cable provides required power for electrolysis processes in the EC and HRG cells. In the pilot test project (phase 3) the system was designed

to be controlled by one electronic unit (Umbilical¹²). However, it should be noted that in the new design of SWIT (Industrialization project) due to the higher power requirement and customers' requirements, several control canisters are designed in comparison with the old design.

4.4.1. SWIT Control System

SWIT control system consists of 4 major modules:

- Topside Master Control Station (MCS)
- Subsea Router Module (SRM)
- Subsea Electrical Module (SEM)/ treatment control canister (TCC)
- Subsea Quality Control Module (QCM)

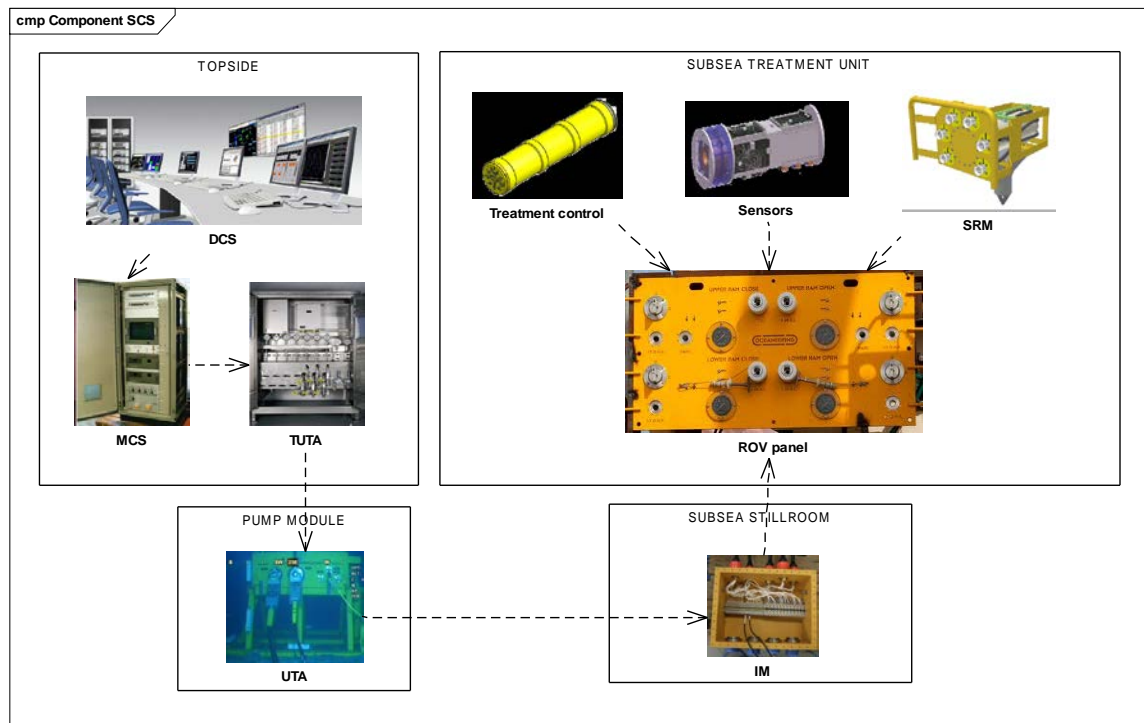


Figure 4.9: Subsea Control System [Courtesy of Seabox]

4.4.2. SWITs Power Supply

The power for SWIT can be supplied from field host platform, the independents platforms with sufficient power supply capabilities or land/wind and tidal power.

The result from pilot testing project has shown that the platform power supply was sufficient for the SWIT components.

In the industrialization project (SWIT new design) the power supplies can either be operated in auto mode (internal controlled) or in manual mode (externally controlled). The

¹² Umbilical: is a system on the seabed to supply necessary control, energy and chemicals to subsea oil wells and all types of subsea system requiring remote control.

power supply consists of two converters, a boost converter and DC/DC converter. The power supply is used for both EC and HRG cells. There is a controller board in the treatment control unit (subsea electrical module) which handles the communication between the power supplies and topside. [117]

4.5. SWIT Pilot Plant

A full scale pilot plant was constructed and installed on the seabed of Oslo fjord at a depth of 65 meters. It was intended to operate for a full years seasonal cycle, in the end it ran from from July 2009- October 2010 (15 months). The project was a part of a joint industry project

(JIP) with Shell, TOTAL, Conocophilips and GDF Suez, the Norwegian Research Council and Seabox [59]. The main objective of this JIP and pilot testing was to establish confidence in the proposed technology of subsea water intake and treatment to a status where an operator can 100% be sure to choose this new technology on a specific field application.

During the seabed pilot testing at the seabed, in order for SWIT to be considered as an alternative to topside water treatment, issues such as, water quality capabilities, ability to perform remote operation control of the treatment system and system reliability were studied.

The formulation and procedure for full scale testing on the seabed in cooperation with the oil companies was based on test results and investigation on previous development work and standards from DNV (for evaluation of qualification procedure for new technology (DNV-RP-A203)).[58]

4.6. SWIT Operating Conditions during Full Scale Pilot Testing

For the type of the duration testing required for SWIT pilot plant, it was necessary to run at steady state conditions or near the steady state as possible in order to be able to observe the effects on parameters that take a long time to be observed (e.g. build up of biofilm and bacteria activities). The other effect of running as near to steady state conditions would enable any effects of seasonal variations to be observed. [58]

Table 4.1 shows the parameters that were chosen at precommissioning for the pilot test.

Table 4.1: Operation parametes.[58]

Parameters	Comments
Flow Rate	50 m ³ /h (7,500 bbl/d)
Electro chlorinator	20A- 1 Cell (of 3)
Hydroxyl Radical Generator	3A- 2 Cells (of 6)
Biocide Shock Dose	Reduced from 50 liters of concentrated gluteraldehyde injected within 15 min [initially once every two weeks then dosage to 25 liter once every 4 weeks for 9 month]

4.7. SWIT Water Quality

Water quality monitoring has been conducted in Oslo fjord by NIVA¹³ at their Marine Research Centre (MFS). The results of this testing program were compared with water quality from topside water treatment into an oil reservoir for secondary recovery purpose. Therefore, analysis have been conducted on the key areas such as effect of reservoir sweep efficiency to avoid blocking the reservoir with solids (particle size) and biofilm formation. All quality test were in accordance with the international standards NS-EN ISO/IEC 17025. Table 4.2 shows an overview of water quality testing program.

A range of samples were analysed for SWIT treated water and compared against non treated seawater. A submerged lift pump was used to induce flow through the subsea treatment unit up to a control container at NIVA centre. The control seawater was extracted from the same depth (65 m) as the SWIT “Still Room” was located.

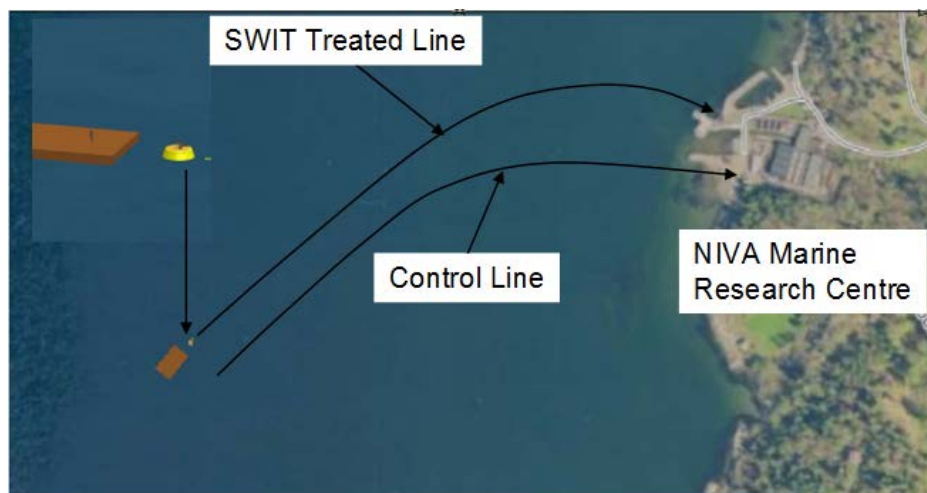


Figure 4.10: Routing of SWIT Treated Line and Control (Non treated) Line [58]

At NIVA, the SWIT water lines was separated in into two. One was periodically exposed to a biocide shock dose and one that was never exposed to the biocide shock dose. The third control sample point was to establish a base line against the treated seawater. Figure 4.12, shows simplified sample point locations.

¹³ NIVA: “is Norway leading multidisciplinary research institute in the field of use and protection of water bodies and water quality, in fresh and marine waters”. [64]

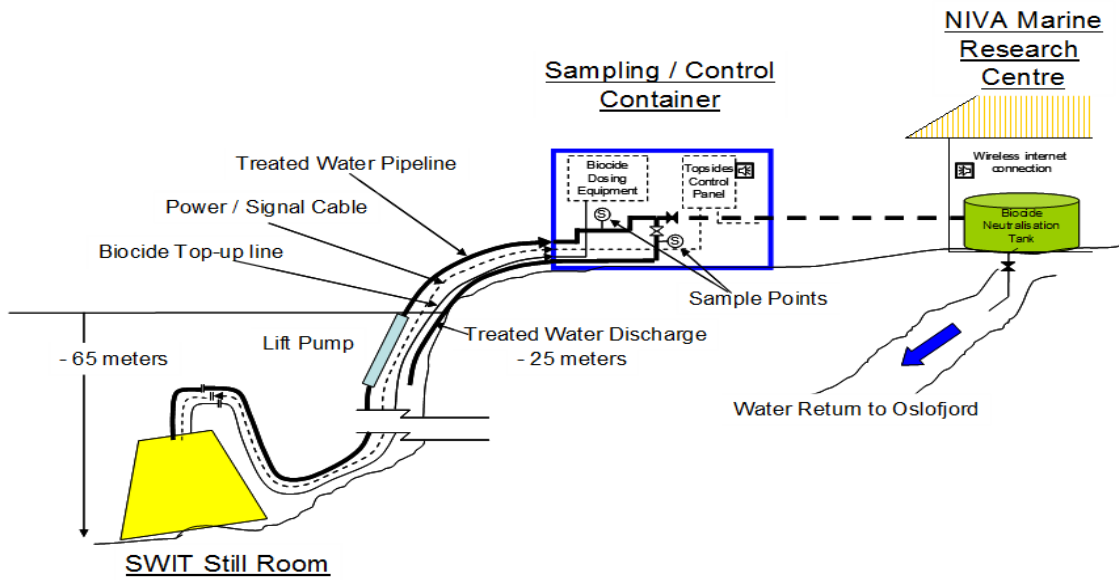


Figure 4.11: SWIT Sample Point Location [Courtesy of Seabox]

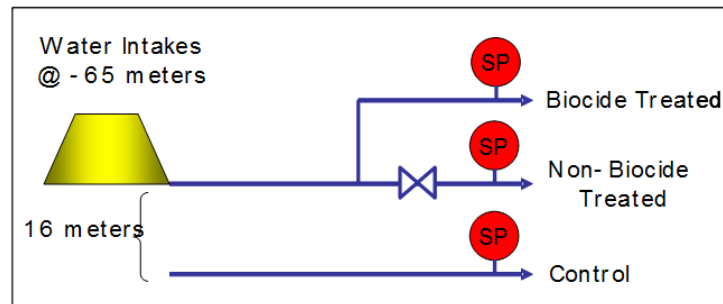


Figure 4.12: Simplified Sample Point Locations Schematic [Courtesy of Seabox]

Table 4.2: Overview of water quality testing program of SWIT. [58]

Monitoring and sampling	Method	Reading/ Sampling Location	Sampling Frequency	Values	
				Non Treated Seawater	SWIT
Chemical Water Quality Measurements					
Temperature (°C)	Continuous logging of quality of water from 60 m depth	Data logging program at the MFS research station	Continuously	-	6-10
Salinity (ppm)	Continuous logging of quality of water from 60 m depth	Data logging program at the MFS research station	Continuously	-	34700
pH	Continuous logging of quality of water from 60 m depth	Data logging program at the MFS research station	Continuously	-	8.02-8.25
Dissolved Oxygen (mg/l)	Continuous logging of quality of water from 60 m depth	Data logging program at the MFS research station	Continuously	-	9.5
Operational Performance of Treatment Units					
Water flow	Reading flow on main flow meter in container, and flow meter on each BETR tube	Flow meter in container and from control sampling point inside the MFS station	Daily		
Total residual oxidants (TRO) (mg/l)	DPD method	Treated water sampled from sampling point in the container. Untreated water from control sampling point inside the MFS station	Once a week	-	0.2±0.08
Redox potential (mv)	Laboratory Orion prob and online Walchem	Treated water sampled from sampling point in the container. Untreated water	Once a week	314±56	507±130

	instrument	from control sampling point inside the MFS station		
Efficiency of Treatment System				
Planktonic Bacteria Water Analysis				
General aerobic bacteria sulphate reducing bacteria (Planktonic)	-Serial dilution method [61] -Most Probable Number (MPN) [62]	Both biocide and non-biocide treated water samples from sampling points in the container. Untreated water sample from sampling point inside the MFS station	Four times during the test period for GAB and SRB	
Biofilm Analysis for Sessile bacteria				
(GAB) and SRB analysis of biofilm from studs in treated water and untreated water (Sessile)	Serial dilution method Most Probable Number (MPN)	Studs from BETR tubes transferring biocide treated and non- biocide treated water in the container and control sampling point inside the MFS station	15 times during the test period	
Chemical Water Analysis				
Total organic carbon (TOC) Dissolved organic carbon (DOC)	NS-ISO 8245 (Standard)	Non-biocide treated water from sampling point in the container. Untreated water from control sampling point inside the MFS station	Once a month	
Total suspended solid (TSS)	TMO 173 (Standard)		Once a week	
Turbidity	HACH turbidity prob		Once a week	

4.8. Pilot Testing Results

4.8.1. Solid particles removal

The sample results were based on visual inspection of solid settled out in the “Still Room”, total suspended solids (TSS), silt density index (SDI), turbidity, microscopic inspection, Millipore filters and Computational Fluid Dynamics (CFD) analysis. The results have shown that more than 99% removal of inorganic solids greater than 15 μ can be expected. Figure 4.13 shows some of the results achieved by the particle size analysis.

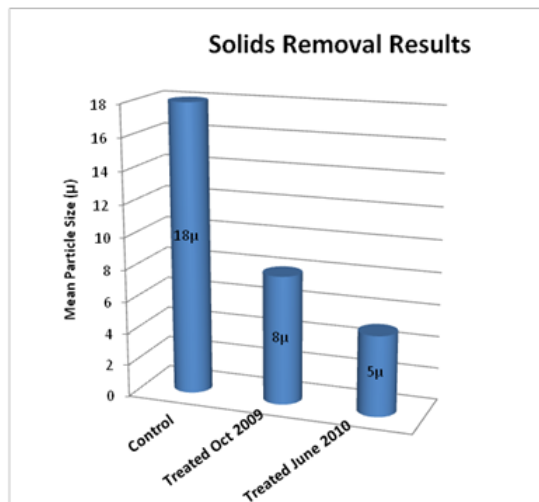


Figure 4.13: Solid Removal Results [Courtesy of Seabox]

It should be noted that non treated control solids conditions were outside the control of solid removal test and were dependent on factors like: tidal movement, ongoing storm conditions and run off water into the Oslo fjord. It can therefore be expected that control conditions will vary up and down but it is reasonable to assume that the treated water will remain fairly constant due to the resident time afforded within the system. [58]

4.8.2. Biofilm

The test set-ups for examining the formation of biofilm from treated seawater with biocide in comparison with non-treated seawater showed little or no sign of biofilm build-up for the duration of testing on test equipment. Figure 4.14 shows the effect of biocide and biofilm formation for the duration of the testing.



Figure 4.14: Pipe Wall Samples, Biofilm build-up over test period [Courtesy of Seabox]

After retrieval of the SWIT unit from the seabed after 15 month of operation, only the roof of the inlet chamber of the unit, which had not been treated by chlorination or hydroxyl

radicals, was covered with a layer of biofilm formation. It was another evidence of no biofilm build up would be expected from SWIT treated seawater injection.

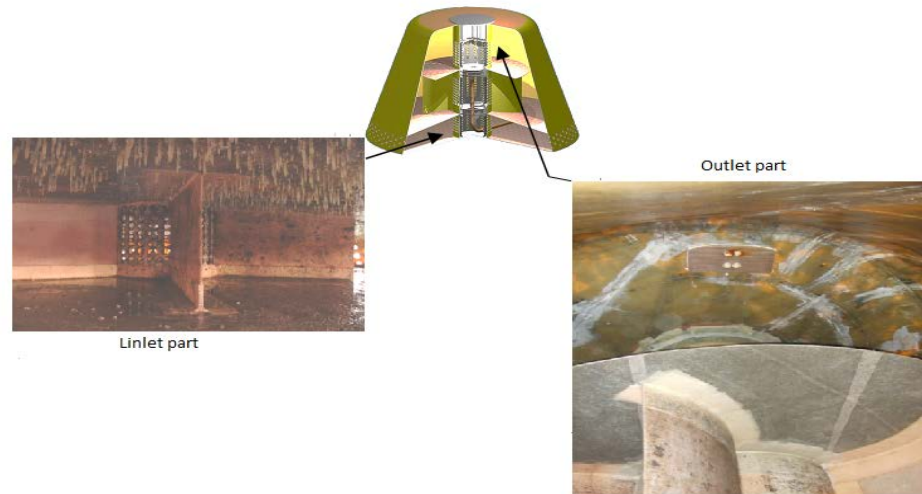


Figure 4.15: Comparison between Inlet and Outlet Chamber of the Still Room [59]

4.8.3. General Aerobic and Sulphate Reducing Bacteria (GAB) and (SRB)

The two different types of bacteria were monitored using standard oil industry techniques. Information about various tests and methods can be found in Table 4.2.

Positive results for both GAB and SRB were found in all samples from non treated control line. By comparison, no bacterial activity results were detected in the SWIT subsea treated water for the duration of the test (15 months).

4.9. SWIT System Reliability

As can be seen from Table 4.3 the project demonstrated a robust and reliable method for treating seawater. From the data, it was concluded that the system had a 99.8% uptime¹⁴ compared with a topside water treatment plant norm of 85-95%.

¹⁴ Uptime: is a measure time of a machine that has been working and available.

Table 4.3: Operational data on availability of the SWIT pilot testing (July 2009- August 2010). Adapted from [58]

Period	Running Hours Available	Down Time (Hours)	Description	% Uptime
July (4 days)	108	2	Program Debugging	98,15%
August	744	7	Program Debugging	95,16%
		29	Power Cut	
September	720	0		100%
October	744	5	Reliability	96,91%
		11	Improvement Experimentation	
		7	Pressure Switch Trip	
November	720	0		100%
December	744	5,5	Power Cuts	99,26%
January	744	3	EC Grid # 1 Failure	99,60%
February	672	0		100%
March	744	0		100%
April	720	0		100%
May	744	0		100%
June	720	0		100%
July	744	0		100%
Agust (23rd)	552	0		100%
Total	9420	69,5		99,80%

For safety and environmental reasons, the operational aspects of start/ stop of the seawater lift pump and biocide shock dosing were required to be performed locally at site in that time remote monitoring was possible via the internet.

Overall, the test results from SWIT were very encouraging for bacterial and biofilm control, settling of solids, with minimum usage of biocide chemicals.

The following part summarized the next stage of SWITs development.

4.10. SWITs Development Project

In Chapter 2, it was described that for secondary recovery, reaction of seawater with formation water is an issue requiring a lot of consideration. Because, seawater contains 2,800 mg/l of sulphate ions and formation water in the reservoir will contain a large amount of constituents (e.g. Barium). This barium can react with injected seawater sulphate ions causing barium sulphate scale. On a topside seawater treatment plant, sulphate content will be removed from water by using "Sulphate Removal Technology".

The removal of sulphate from seawater by membrane technology prior injection can therefore help oil companies to prevent sulphate scaling and potentially allow mixing formation water and seawater for injection. [115]

4.10.1. SWIT Combined with Membrane

In previous testing, full scale SWIT pilot test results have revealed a number of advantages regarding water quality achievable with, little /no liquid chemical usage and low energy consumption.

A Joint Industry project was conducted to examine the potential benefits of using the new SWIT technology in combination with membranes. The testing was carried out for 9-month in Oslo Fjord at the Norwegian Institute for Water Research (NIVA) (August 2012-May 2013).

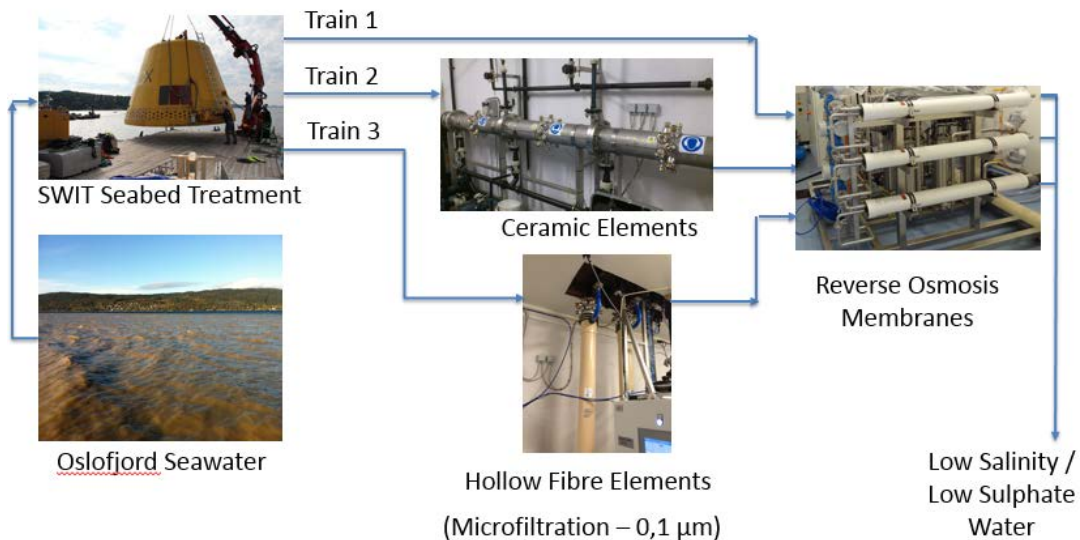


Figure 4.16: SWIT Combined with Membrane Test Set-up [Courtesy of Seabox]

As can be seen from the test set-up, experimentation was made possible with various equipment combinations and different ways of operating and regenerating that equipment. Testing showed that each item of treatment equipment had its own job to do when it came to enabling long operation lifetime of sulphate removal/ salinity reduction membranes.

- SWIT treated and disinfected the seawater.
- Micro Filters consistently remove all suspended particles.
- Reverse Osmosis membranes removed dissolved solid from seawater.

The results obtained during the operation have shown:

- More than 99% Reliability.
- Using a combination of SWIT and Hollow Fiber Microfilters, the same RO membranes were able to operate for the duration of testing without cleaning and could have lasted a lot longer.
- Micro Filter units have worked very well without air scour backwash or chemical clean with SDI<1.

The ultimate goal of the testing is to be able to produce low salinity / low sulphate water on the seabed. This testing has revealed the best equipment selection and best methods of operating that equipment that will give the best chance for achieving a feasible subsea membrane treatment system.

The above combination process can open up the possibility to produce “tailor made” water and even fresh water much more effective than with current topside sulphate removal technology or desalination process.

5. COMPARISON BETWEEN SWIT AND TOPSIDE SEAWATER TREATMENT SYSTEM

Sweep efficiency, reservoir souring and corrosion are three criteria's that are acknowledged as being the principal factors of water quality [65]. Failures due to the mentioned issues can have huge consequences for; offshore drilling activities, lost production potential, reduced value of hydrocarbons and limited export options [115]. In Chapter 3, it was mentioned that operator companies, in order to maximise oil recovery and reduce the failures due to the poor water quality, must treat seawater before injection it into the reservoir Table 5.1 summarises the necessary topside treatment of seawater prior to injection in the reservoir.

From an HSE prospective, in dosage of chemicals and high power consumption for treatment of seawater on the Topside, represent impacts on health, safety and environment.

Chapter 4 introduced SWIT as a new technology for treatment of seawater on the seabed, which feeds directly into the injection wells. Table 5.2. Summarises the necessary subsea treatment of seawater prior to injection in the reservoir.

SWIT in order to be accepted as a viable water treatment process, the system has been tested on the seabed with the help and funding of several large Oil Companies such as ExxonMobile, Shell, Statoil, Conocophilips, Wintershall, Lundin, TOTAL and GDF SUEZ. During the full scale pilot testing (Phase 3) the Oil Companies implemented their own assessment of the SWIT treatment technology. The basis for this was a work process that assessed "Technology readiness level" (TRL). Each company has a different method for assessing TRL but most are based on .the DNV- RP-A203-2001¹⁵ procedure.

The results from the test have shown that the new subsea treatment system has produced some very good water quality that compares favourably with water quality achievable from topside seawater treatment systems. Quality of seawater is the same / if not better in enabling sweep efficiency, preventing reservoir souring with less chemical usage and less energy consumption.

The following part compares SWIT with topside treatment system from various angles such as chemical usage, power requirement, equipment's and materials.

¹⁵ DNV RP-A203-2001: is a tool for identification of risks and technology gaps that could exist between existing technology (e.g. Topside water treatment system) and a new technology (e.g. SWIT treatment unit).

Topside Water Treatment System

Table 5.1: Summary of topside seawater treatment requirement.

Equipment	Chemical Treatment	Duty	Treatment Dosage
Seawater Lift Pump		Seawater lift from sea to platform	Pressure rise to ca 14 Barg
Electrochlorinator	Chlorination	Disinfection	0,5-1,0 mg/l (dosage)
Chemical Injection Package		Injection of liquid based chemicals	
Coarse Filters		Removal of large particles	Removal of all particles >80 microm
	Filter Aid (Flocculant)	Removal of fine particles in fine filters	2-10 mg/l (dosage)
	FilterAid (Coagulation)	Removal of fine particles in fine filters	2-10 mg/l (dosage)
Fine Filters		Removal of fine particles	Particle Removal down to 2-5 micron range
	Antifoam	Prevention of foaming in Deaerator Tower	2-10 mg/l (dosage)
	Biocide	System disinfection	Site dependant
Deaerator Tower		Removal of Dissolved Oxygen	
	Oxygen Scavenger	Removal of residual dissolved oxygen	15-30 mg/l (dosage)
	Corrosion inhibitor	Corrosion prevention	5-30 mg/l (dosage)
Cartidge Filter		Polishing filter (if required)	Particle removal down to 2 micron range
Booster Pumps		Pressure raising- NPSH for Injection Pumps	Pressure rise to ca 14 barg
	Scale Inhibitor	Scale prevention	5-30 mg/l (dosage)
	Biocide	System disinfection	400-4000 mg/l Shock dose (Site Dependent)

Subsea Seawater Intake and Treatment System (SWIT)

The table below illustrates a summary of subsea seawater treatment technology.

Table 5.2: Subsea seawater treatment system

Equipment	Chemical Treatment	Duty	Treatment/ Dosage
Still Room		Solids sedimentation / residence time	Removal of all particles >15 microm
Seawater lift pump		Seawater lift from sea to platform	Pressure rise to ca 14 Bar
Electrochlorinator	Chlorination	Disinfection	0,3- 0,5 mg/l (Dosage)
Chemical Injection Package		Injection of liquid based chemicals	
Coarse filters		Removal of large particles	Removal of all particles >80 microm
	Filter Aid (Flocculant)	Removal of fine particles in fine filters	2-10 mg/l (dosage)
	Filter Aid (Coagulation)	Removal of fine particles in fine filters	2-10 mg/l (dosage)
Fine filters		Removal of fine particles	Particle removal down to 2 - 5 micron range
	Antifoam	Prevention of foaming in Deaerator tower	2- 10 mg/l
	Biocide	System disinfection	Site dependant
Deaerator tower		Removal of Dissolved Oxygen	
	Oxygen scavenger	Removal of Dissolved Oxygen	15-30 mg/l (dosage)
	Corrosion inhibitor	Corrosion prevention	5-30 mg/l (dosage)
Cartridge filter		Polishing filters	Particle removal

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		(if required)	down to 2 micron range
Booster Pumps		Pressure raising NPSH for Injection Pumps	Pressure rise to ca 14 Bar
	Scale inhibitor	Scale prevention	5-30 mg/l (dosage)
	Biocide	System disinfection	400 - 4000 mg/l - Shock dose (site dependant)
Hydroxyl Radical generator		System disinfection	No residual
	Biocide (if required)	System disinfection	1000 mg/l once / month (site dependant)

5.1. Issues Effecting Sweep Efficiency

Sweep efficiency in the reservoir is compared from three aspects below and look at the principle differences between performing water treatment on a topside and water treatment at subsea location (SWIT).

- Reservoir blocking (e.g. due to the particles)
- Reservoir blocking in the “Near Well bore Area” (e.g. due to biomass)
- Scaling

5.1.1. Reservoir Blocking

SWIT Treatment

Results show that all the methods used for solid analysis indicate a reduction of solids level between untreated seawater in the control line and water sample from SWIT treated line. The average particle size results show a water quality with particle size below 10 μ , typical solid concentration of 0,5 ppm and SDI measurement of 5. These results indicate that the solid in water quality is within the normal range associated with seawater injection. The SWIT solid settling effectiveness has been further confirmed when the SWIT was removed from the seabed for examination after completion of the test. [59]

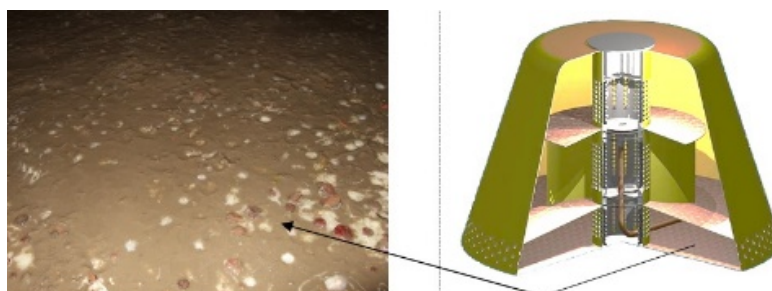


Figure 5.1: Solid remaining in the "Still Room" after retrieval [Courtesy of Seabox]

To understand the significance of SWITs results, it is necessary to compare them with topsides water injection treatment system.

Topside Water Treatment Plant

Topside water treatment plant will require a series of filtration units (e.g. fine filtration) to get the same level of solid removal as the SWIT has achieved within the “Still Room”. Topside filtration units are prone to a number of contamination sources such as drilling fluid discharge, produced water, sewage and seasonal organic variation. Therefore, a range of chemicals (e.g. filter aids, coagulant and flocculants) must be dosed (2-10 ppm) into the filtration units to remove the solid particles down to a level of 2-5 μ . A common problem observed with topside treatment that can be mentioned is pick up of solids again (e.g. biofouling and corrosion products) downstream of the filtration system on the way to the injection zone in the reservoir.

Although most of the chemicals used on the Norwegian Continental Shelf (NCS), have low environmental impact the danger of long-term effects and damage to operational personnel cannot be eliminated. [66]

Therefore, it can be concluded that the SWIT provide adequate solids removal with no extra chemical dosing. SWIT water quality is simpler to achieve than via topside filtration and less prone to platform discharges in comparison with topside solid removal. Further fine filtration would be required if operators strive for matrix flooding but a lot of operator companies consider topsides fine filters to be unnecessary treatment and only include for coarse filtration with solid removal down to 80 μ level. [58]

5.1.2. Reservoir Blocking in the “Near Well Bore Area”

Various factors such as; temperature, microbial quality of intake water, concentration of nutrient (e.g. carbon and nitrogen sources) surface material, hydraulic shear force, and concentration of disinfectant residual, play an important role in the formation of biomass.

Water taken from the seabed will therefore be expected to contain low concentration of factors that promote bacterial growth. The potential for contamination from other possible sources such as, drilling fluids; produced water and sewage are lower on the seabed in comparison with water taken from higher in the water column.[67] [58]. Therefore, when comparing SWIT to a topside treatment system, there are some inherent subsea treatment benefits for free.

SWIT Treatment

In Chapter 4, it was mentioned that after 15 months of SWIT pilot testing, the results have shown no sign of development or formation of biofilm on the two sample lines compared to untreated seawater (raw water) in the control line. Figure 4.14

Electrochlorination (combined with a long reaction time) and HRG were efficient in delaying the onset of biofilms. In addition to that, a shock dosing of biocide (a duration of 15 - 30 min) also helped to reduce any sign of biofilm build up. However, the remarkable results of no biofilm growth after 15 months of testing indicates how well the system had worked and indicate there is no need for biocide shock dosing.

From an environmental point of view, there is a good ground to assume that SWIT will enable a cleaner environment in the reservoir and near the well bore with no biocide injection in comparison with topside biocide treatments.

Further, from other aspects a benefit with a cleaner environment in the well bore may also be enable future “tertiary recovery” techniques such as Low Salinity Water or CO₂ injection. [58]

Topside Treatment

Despite the extensive amount of chemical and physical treatment on topside, it is estimated that 70% of water injection wells are sour in the near wellbore area. This can be attributed to failure to control biofouling and bacteria (SRB). [9]

In Chapter 3, it was described that oxygen is removed from the treated water primarily for corrosion control of equipment downstream of the deaerator tower. However, there are

also process consequences for injecting deaerated seawater. Since SRB can only grow in a deaerated environment, the conditions are made available for proliferation of the bacteria that remain after limited reaction time with the chlorine in all equipment from resistance section of the deaerator down to the reservoir.

Therefore, most topside systems chose to have deaeration unit and invest on a biocide shock dose program (400 – 4000 ppm weekly for 3-4 hours) that performs system disinfection to prevent the formation of biomass. In a deaeration tower, various oxygen scavenger (15-30 ppm) and antifoam (2-10 ppm dosage) chemicals must be dosed to the system to remove the oxygen and avoid foaming.

In summary the results from SWIT water quality testing indicate that there is no need for deaeration (oxygen removal) and injection of chemicals (oxygen scavenger and antifoam) because corrosion resistant materials are used for the (much less) equipment between the SWIT and the injection well.

Avoiding use of oxygen scavenger and corrosion inhibitor chemicals (which are harmful for marine species) will have a beneficial environmental effect.

More information about use and discharge of chemicals will be discussed in Chapter 6

5.1.3. Scaling

Scale formation in water treatment system was known as a problem when seawater is exposed to produce water or other non-compatible water. Therefore, dosage of scale inhibitors (5-10 ppm) to reduce the chance for scale formation are always normally required for topside treatment.

In a case of scaling, it is possible to inject chemicals (scale inhibitor) to the SWIT treatment unit via the subsea umbilical or doing squeeze treatment at time of well completion. [58]

There is therefore no significant difference between SWIT and a topsides scale inhibitor dosing system

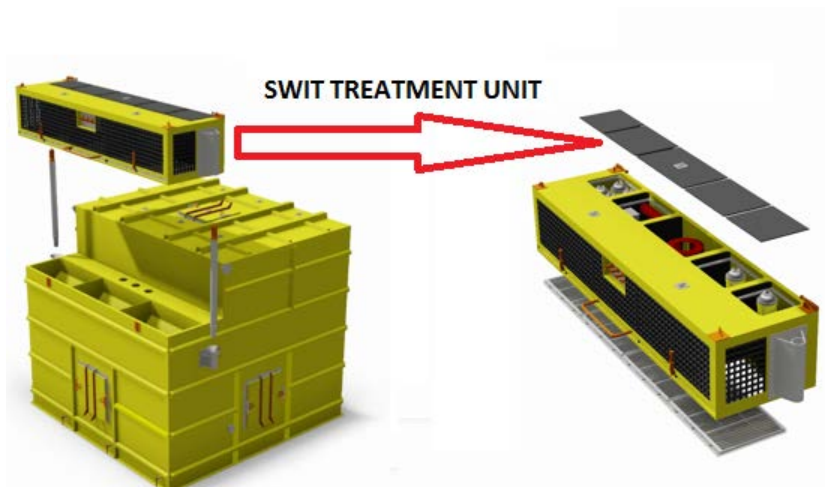


Figure 5.2: SWITs Chemical Treatment Unit [Courtesy of Seabox]

5.2. Materials

5.2.1. SWIT System

After water is treated in a SWIT treatment system the activity of any remaining SRB is prevented due to the presence of dissolved oxygen (maintaining aerated conditions). However, the use of aerated seawater requires the use of corrosion resistance materials. Therefore, SWIT equipment and equipment from the SWIT unit to the reservoir should be made from corrosion resistant material or should be lined with corrosion resistance material. This equipment includes SWIT “Still Room”, seawater injection pumps, subsea injection wellhead and well tubulars [68].

5.2.2. Topside Treatment

Corrosion issues are well known for topside treatment system and in order to reduce the corrosion problems, it is normal to use corrosion resistance material such as coating, fibreglass, titanium and cupronickel for all equipment up to and including the deaeration tower.[58] [69]

- Lift pump caisson
- Lift pump equipment
- All topside WI pipework to deaerator
- Coarse filter skid
- Chemical injection pump skid and injection tanks
- Electro chlorination skid
- Fine filter skid
- Vacuum pumps
- Deaerator tower

In order to reduce the costs associated with materials and equipment, the following equipment downstream of the deaerator will be made of cheaper material such as carbon steel.

- Booster pump
- Xtree
- Seawater piping and HP injection manifold
- Subsea HP injection flow line
- Well tubular

Several oil field operator companies are now concluding that cost saving associated with the combination of carbon steel material in their water injection processes is not a smart economical saving solution (due to the equipment lifetimes). Therefore, demand from operator companies on using superior materials are increasing. One example on the NCS is

Statoil who have used superior material (e.g. titanium) for all WI equipment on several fields including Heidrun and Snøhvit fields in order to avoid corrosion in the operation process. [70]

It can be concluded that SWIT is more economical than topside treatment system in the case of using corrosion resistance material. The reason is SWIT will be installed on the seabed therefore; it is a shorter vertical well to access the part of the reservoir (no requiring for long directional drilling). The other advantages with SWIT in comparison with Topside is less materials use for equipment's it leads to less steel production required (less mined, iron, less power to produce the steel) From an economical points of view it has effect in less manufacturing welding and assembly costs.

5.3. Power

In the offshore oil and gas industry, nearly all equipment needs electrical power to operate. In order to produce the required electrical power, gas turbines are normally used.

For water injection systems from topside, a gas turbine must generate the required power for all of the electrical motors for:-

- Lift Pumps
- Booster Pumps
- Vacuum Pumps
- Chemical Injection Pumps
- Hydrogen blowers
- High Pressure Water Injection Pumps (where direct drive turbines are not used)

Water injection on topsides therefore uses a lot of electrical power, which ultimately has an effect on exhaust gases (mainly CO₂/ NO_x) from the combustion chambers in the turbine.

From an environmental aspect in addition to high-energy usage, emission of gases in to the air are not desired. The reason is the impacts of CO₂/ NO_x on environmet.

When the SWIT treatment system is compared with topside treatment, the only significant power user is the subsea HP Water Injection Pump. It is clear to see that the amount of power required to get the same amount of water at the same pressure to the injection point in the reservoir is significantly less. Power saving (13 -15%) can be expected which means savings in the in the 1 – 1,5 MW for a 160,000 bbld injection system.class

From an environmental view of lowering usage of electrical power has significant CO₂ and NO_x reduction in to the air. More information about emissions and discharge of gases into the environment plus a detailed SWIT power comparison with topside) will be discussed in Chapter 6.and 7

5.4. Manning Level

SWIT in comparison with Topside treatment system requires less manning to operate subsea water injection plant. The documents and calculations on manning's level of SWIT have shown that SWIT system needs less offshore personnel to run the subsea water injection system than to run Topsides plant. From an HSE perspective also every person offshore represents danger both to himself and other.

More information about manning level comparison between SWIT and Topside will be discussed in Chapter 7.

6. UNDERSTANDING OF ENVIRONMENTAL IMPACTS FACTORS

The most basic mission of the oil companies is to extract hydrocarbon from the reservoir and then to make oil useful and available to customers with a safe, healthy and environmentally manner. For environmental authorities, this means no accidents, no harm to people and no damage to the environment. Operator companies in order to achieve the goal and meet environmental considerations, must drive down the environmental and health impact of the operations by reducing emissions, discharges, waste and using energy efficiently. SWIT was introduced as a new technology, which has shown significant possibilities in various areas such as increase oil recovery, lower OPEX and CAPEX, regulatory, production and environment, health & Safety (HSE) in comparison with traditional WI systems. In order to give a better understanding of SWIT's environmental influences and evaluate SWIT from environmental aspects, this chapter attempts to answer the questions below:-

- Why is there a high environment focus on offshore petroleum industry?
- How oil companies meet environmental challenges?
- How new and latest technology such as SWIT can help oil companies to improve and develops their environmental frameworks?

6.1. Development in discharge and emission from offshore installations on the Norwegian Continental Shelf

Protecting the environment has always been an integrated part of the petroleum activities. In order to ensure that Norway can combine its role as an oil producer with being a pioneer in environmental issues, various regulations, policy instruments, environmental management tools and systems have been developed by environmental authorities. For instance, Norway has been taken the climate pollution as a serious issue and introduced CO₂ tax for petroleum operations early in 1991. This tax has led to development of the technologies and solutions that has effect on reducing of CO₂ emission to the air.

The operator companies and environmental authorities have cooperated closely to reach the objective of zero environmentally hazardous discharges to the sea from the petroleum activities. The results are reducing environmental impact of production chemicals. Statoil is one the oil companies in Norway that has set as an objective of zero harm to the environment, which is defined as conserving biodiversity, limiting emission, discharge and limiting land use. [73] [74]

6.2. Overview of Environmental Issues Offshore

The different phases of petroleum activities lead to different environmental impacts such as emission to the air, discharge to the sea and production of waste. [1]

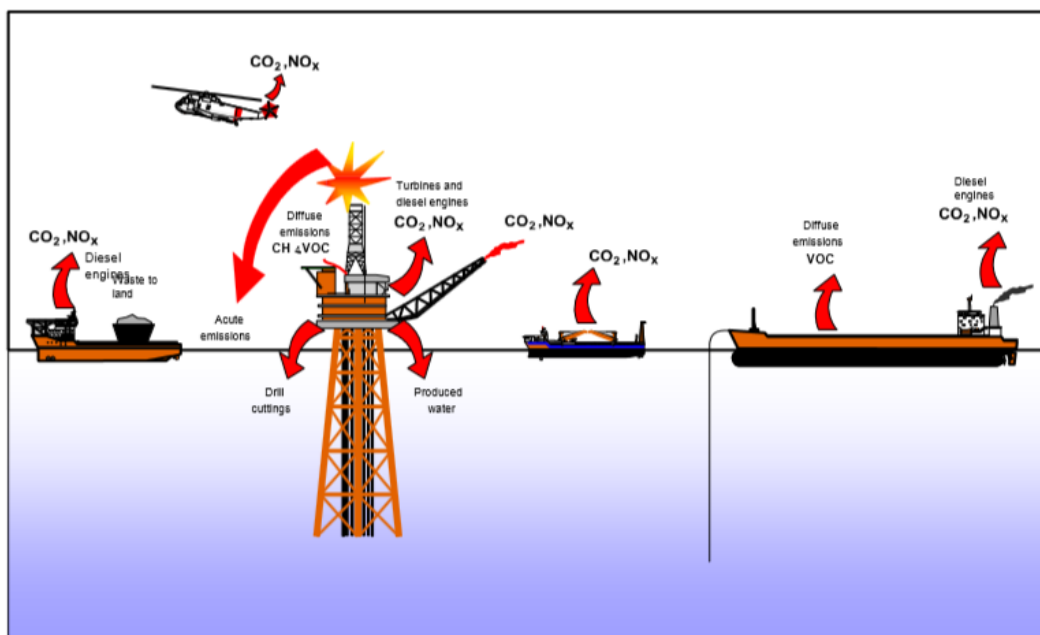


Figure 6.1: The most Important Environmental Impacts from Oil and Gas Operations [1]

An understanding of emissions of gases and discharges of chemicals from offshore activities based on information from Norway will be provided in this section. Management and handling of waste is not included in this thesis work.

6.3. Discharge to the Sea

Discharge to the sea from the offshore facilities are mainly include residue chemicals (from operation and production facilities), drillings cutting, cement from drilling operation and produced water. Discharges of oil and chemicals can have direct local effects on fish and other marine species around the platform facilities and are regulated nationally through discharge permits based on the Pollution Control Act.

It should be noted that the discharges are also subject to international regulation through the Oslo-Paris Convention (OSPAR). Use and discharge of chemicals is regulated in the form of requirement for risk assessment and classification according to the properties of chemicals. For example, in OSPAR controlled areas, more than one million tons of chemicals are realised to the marine environment every year. Based on chemical hazard assessment and risk management model (CHARM) most of these chemicals are classified as environmentally friendly and they do not have harmful effect to the environment [76]. The statistic results published by Norwegian Climate and Pollution Agency (KLIF) shows that more than 99% of the chemicals used in Norwegian oil sector are classed as environmentally friendly, however there are still some chemicals, which impact the environment [75]. A Logical question is therefore, what is the fate of these chemicals in the receiving environment?

6.4. Chemicals and Environmental Challenges

In the offshore petroleum industry, chemicals are normally used in; water treatment systems, production systems and hydrocarbon transport in different phases (gas/ liquid).

For example, in Chapter 3, it was addressed that oxygen scavenger, biocides, antifoam, filter aids, scale and corrosion inhibitors will be dosed into a water injection system to meet the water quality demanded by the reservoir. Most of the chemicals are mixture of various materials with different properties (e.g. organic or inorganic) and different solubility effects. This means that the fate of the chemicals in the receiving environment are different. Some of chemicals are 100% soluble in oil and will follow oil and go to the refinery with the crude oil. Some of them are water soluble and end up in the produced water and in discharged streams into the sea. Other operational scenario's (e.g. start-up) mean that flowing direct to sea is required whilst the treatment plant establishes water quality prior to injection. Parts of chemicals can be dissolved in both oil and water. It is therefore an overall objective for the industry to improve alternative methods, minimising the use of chemicals and develops the use of greener chemicals.

6.4.1. How oil companies can develop the use of environmentally acceptable chemicals

The discharged liquid chemicals used for water treatment systems and other production facilities undergo a number of biological and chemical reactions after being discharged into the sea. Therefore, there is an increasing concern from environmental expertise about long term impact of treating chemicals on ecosystems and marine organisms. In general, the impact of treating chemicals on the environment will be divided in to two types, "Acute Toxicity" and "Chronic Toxicity" effects. For example, some of treating chemicals that have been discharged into the sea adsorb on the solids and become part of the sediment. Some of treating chemicals react with seawater (e.g. scale inhibitor) and only a small amount of them are still unchanged in water. In order to reduce long-term effect and improve the use of greener chemicals, North Sea environmental authorities and oil industry companies, dependent on the chemical type and predicted fate in receiving environment , have employed different tests and risk analysis tools. [77] [78]

The chemical hazard assessment and risk ranking model CHARM is an analysing tool that was developed widely in North Sea to give chemicals supplier and environmental authorities a good scientific assist in the selection of environmentally acceptable chemicals and analysing the risk of chemicals discharge to the marine environment, according to ecotoxicological properties of chemicals. [81]

The CHARM project was initiated in 1993, the model is based on available data from OSPAR about the chemicals properties (HOCNF) and platform related conditions. During the CHARM project, three important environmental parameters such as biodegradability, bioaccumulation potential and toxicity/acute toxicity will be evaluated on each chemicals.

Biodegradation potential

Biodegradation is a process by which organic components are changed from complex molecules into simpler molecules in both aerobic and anaerobic conditions through chemical processes during the time. Calculation of biodegradation rate (persistence) of chemicals is a beneficial method to indicate which, organic compounds have tendency to accumulate

(resistance to degradation) in the environment. The reason is that some of the chemicals can remain for many decades in the environment and magnify¹⁶ through food chain. [80]

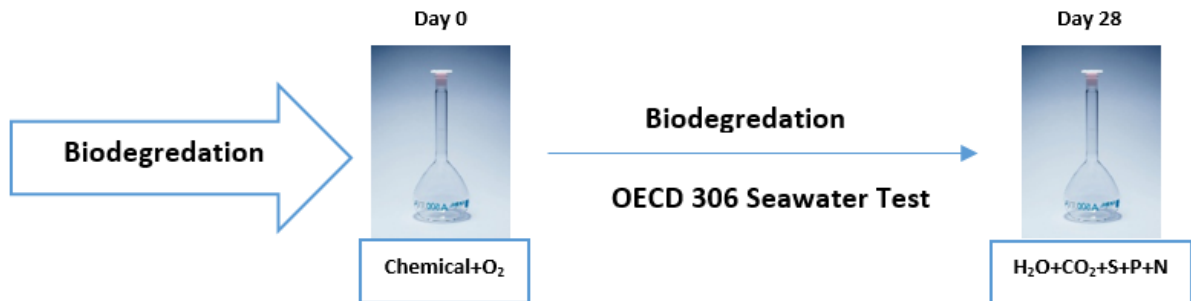


Figure 6.2: Biodegradation Test [Courtesy of Scilabware]

Bioaccumulation potential

Bioaccumulation means accumulation of substances such as hazardous chemical in the body of organisms. For offshore chemicals, CHARM model performs a hydrophobicity test octanol/ water partitioning. The test results indicates the hydrophobicity affect and accumulation potential of chemicals in fat cells of organism (e.g. fish, algae). [79]

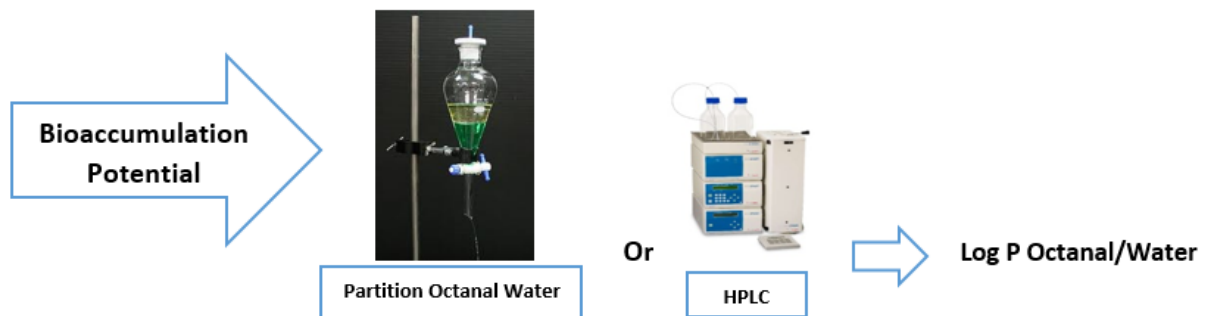


Figure 6.3: Bioaccumulation Test [Adapted from Wikipedia]

Biomagnification: the increasing in concentration of a hazardous chemical in ecosystem that happen from one level of a food chain to the next level.

Bioaccumulation of persistence organic pollutant (POP) is a big problem for animals in the Arctic areas (e.g. polar bears). POP's can be transferred by naturally environmental conditions such as wind and oceanic currents transported from lower latitudes to northern areas and concentrated there. Normally, Northern animals have a lot of fat and can keep toxic persistence chemicals unchanged inside their bodies for a long time. Therefore, environmental monitoring and tests is mandatory for exposure mammals in Northern area of NCS to record early warnings and avoid future problems (e.g. DNA adduct).



Figure 6.4: Effect of Persistence Chemical Pollutant in Northern of North Sea [Courtesy from Wikipedia]

Chemical Toxicity Potential

Toxicity is a degree to which a hazardous chemical is able to damage the environment. Toxicity can refer to the impact on the animals, bacterium or plants. Therefore according to the CHARM model, analysing the toxicity potential for offshore chemicals are based on acute toxicity test on a series of standard organisms such as *Slektenomena costatum*, *Acartia tonsa*, *Corophium volutator* and *Scophthalmus maximus* (fish test) in a period between 48-96 hours dependent on the test conditions.



Figure 6.5: Acute Toxicity Test System [82]

Based on available data from tests, a sigmoidal dose response curve will be formed and this dose- response curve can be used to describe the change in effect on the organism caused by chemicals [82][83]. It should be note that the dose response relationship is a valuable data for both chemical suppliers and environmental authorities to determine environmentally safe and hazardous potential for pollutant chemicals. Figure 6.6 adapted from [82] illustrates dose response relationships.

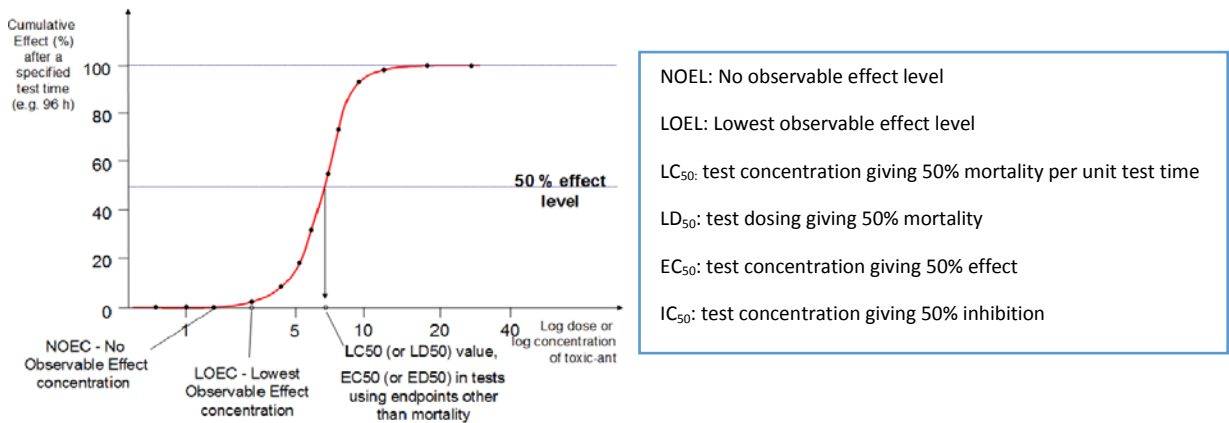


Figure 6.6: Dose - Response Relationship [82]

Environmental regulation laws are classified the chemicals in four colours, based on their ecotoxicological proprieties and test systems (CHARM model).

Black: The most environmentally hazardous chemicals, for which discharge permits, are granted in exceptional cases only.

Red: environmentally hazardous chemicals, the permit requires that these chemicals be prioritized for replacement. (e.g. Glutaraldehyde)

Yellow: Chemicals with acceptable environmental characteristics. Permits are granted without specific requirements.

Green: chemicals listed on OSPAR PLONOR (Pose little or No risk) list, allowed to discharge without permission.

Figure 6.7, shows a table for ecotoxicological evaluation of chemicals and their toxicity properties based on test reports from operating companies. More information about environmental tests guidelines, recommendation and regulations are available on reference [84].

	Category	Colour category
Water		Green
Chemicals on the PLONOR list		Green
Hormone disturbing substances	1	Black
Environmental Toxicant	2	Black
List over prioritized chemicals included in target one on the priority list, Storting White Paper no. 25 (2002-2003)		
Biodegradability < 20% and log Pow > = 5	3	Black
Biodegradability < 20% and toxicity EC ₅₀ or LC ₅₀ < = 10 mg/l	4	Black
Chemicals on OSPAR's tainting list	5	Red
Two of three categories: Biodegradability < 60%, log Pow > = 3, EC ₅₀ or LC ₅₀ < = 10 mg/l	6	Red
Inorganic and EC ₅₀ or LC ₅₀ < = 1 mg/l	7	Red
Biodegradability < 20%	8	Red
Other chemicals		Yellow

Figure 6.7: Eco toxicological evaluation of chemicals [84]

Figure 6.8 shows improvement of greener chemicals in oil and gas industry and the historical development of discharge chemicals are illustrated in Figure 6.9.

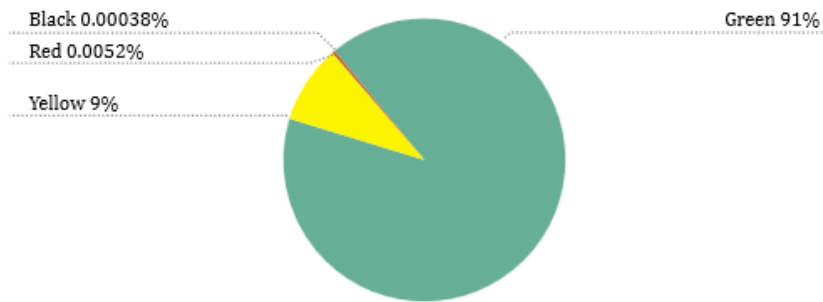


Figure 6.8: Distribution of Chemical Discharge [Adapted from KLIF]

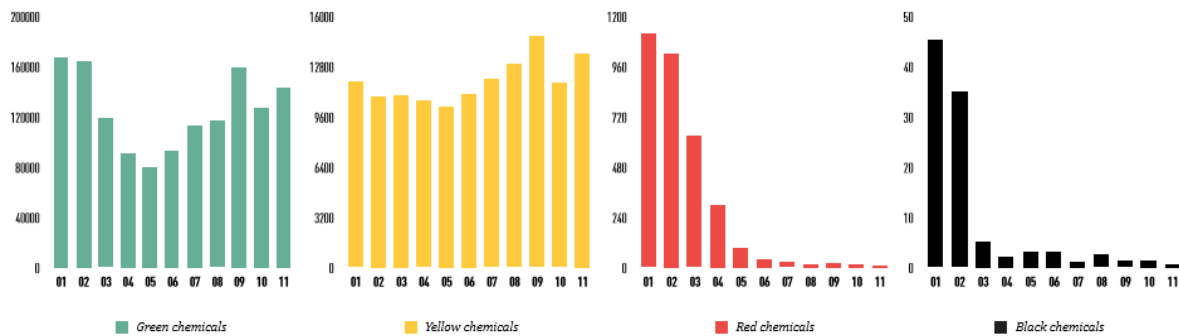






Figure 6.9: Historical Development of Chemicals Discharge (Tonnes) [Adapted from KLIF]

Figure 6.8, shows that 91.3% of injected chemicals are green and 8.7% are yellow. This means that the operator companies have worked purposefully to replace black and red chemicals, which contains poor environmental properties with more environmentally acceptable alternatives (green chemicals). [73]

In addition to CHARM model, the other risk assessment model that have been developed for environmental managements called “dose related risk and effect assessment model” (DREAM). This model able to predict chronic effects on organisms associated with chemical discharges. DREAM includes exposure, uptake and effect calculation for marine organisms exposed to the hazardous chemicals. [80] [85]

An explanation about various impact of chemicals on environment and relevant environmental solutions that can help chemical suppliers, oil companies and environmental authorities to select the chemicals with lower harmful impact was discussed in previous section. Based on information from Nalco chemical treatment company, Table 6.1 is prepared in order to give an overview of ecotoxicological properties of water injection chemicals. According to regulations, all chemical suppliers, for each chemicals must have a safety data sheet with practical HSE information. All information’s must be clear, understandable and available for offshore and operational personnel that have responsibility to handle the chemicals for both injection into the system and discharge to the sea..

Table 6.1: Ecotoxicological effects of topside water injection chemicals [Adapted from NALCO chemical safety data sheets]

Chemicals						
	Biocide	Antifoam	Scale Inhibitor	Oxygen Scavenger	Filter Aid (Flocculant)	Corrosion Inhibitor
Hazard Pictogram		No Dangers			No Dangers	
Hazard Identification	Acute toxicity Category 4	This is not dangerous	Acute toxicity Category 4	Acute toxicity Category 4	This is not dangerous	Acute toxicity Category 4
Acute Oral Toxicity	Harmful	Based on available data, the classification criteria are not met	Harmful	Harmful	Based on available data, the classification criteria are not met	Harmful
Acute Dermal Toxicity	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met
Acute Inhalation Toxicity	Harmful	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Based on available data, the classification criteria are not met	Harmful
Acute Aquatic Toxicity	Very toxic to aquatic life	No harmful to aquatic organisms	No harmful to aquatic organisms	No harmful to aquatic organisms	No harmful to aquatic organisms	Very toxic to aquatic life

Chronic Toxicity	No chronic toxicity to aquatic organisms	No chronic toxicity to aquatic organisms	No chronic toxicity to aquatic organisms	No chronic toxicity to aquatic organisms	No chronic toxicity to aquatic organisms	Very Toxic with long term effect to aquatic life
Biodegradation Ability	It is readily biodegradable	It is readily biodegradable	It is readily biodegradable	Greater than 95% of this product are inorganic substances for which and biodegradation value is not applicable	It is readily biodegradable	It is readily biodegradable
Bioaccumulation	Low potential to bio concentrate	No bioaccumulation	No bioaccumulation	No bioaccumulation	No bioaccumulation	Potential to bio accumulation
Environmental Fate	water soluble and remain primarily in water	It will be float on the surface	water soluble and remain primarily in water	water soluble and remain primarily in water	water soluble and remain primarily in water	water soluble and remain primarily in water
PBT/ vPvB	No substance for persistent, Bioaccumulation nor toxic (PBT).No substance to be very persistent nor very bio accumulating (vPvB)	No substance for persistent, bio accumulating nor toxic (PBT).No substance to be very persistent nor very bio accumulating (vPvB)	No substance for persistent, bio accumulating nor toxic (PBT). no substance to be very persistent nor very bio accumulating (vPvB)	No substance for persistent, bio accumulating nor toxic (PBT). no substance to be very persistent nor very bio accumulating (vPvB)	No substance for persistent, bio accumulating nor toxic (PBT). no substance to be very persistent nor very bio accumulating (vPvB)	No substance for persistent, bioaccumulating nor toxic (PBT).no substance to be very persistent nor very bio accumulating (vPvB)

The data from Table 6.1 shows, operator companies have been very proactive to establishment of greener chemicals in NCS. However, there are still hazardous chemicals, which have an acute toxicity category and therefore influence the environment and damage ecosystems (such as biocide, oxygen scavenger and scale inhibitor). The following parts will explain other possible solutions to meet environmental regulations in NCS.

6.4.2. How it is possible for oil companies to minimise the use of the chemicals

The above paragraphs address how environmental authorities, oil companies (for example Statoil) and chemical industries are cooperating very closely to continuously reduce and stop the use of environmentally harmful production chemicals and develop better alternatives, namely, less toxic and more biodegradable, as well as effective in their use.

An alternative strategy is to minimise the use of chemicals by improvement of chemical injection facilities. In order to minimise the use of chemicals, reduce consumption of the chemicals and improve the environmental aspects, the following parameters should be taken into account. [24] [66]

- A good chemical treatment system is one that contains a full definition of all the related problems, reservoir data and operational parameters.
- In order to determine the necessary chemicals for treatment process and reduced the impact of chemicals, a good sampling and test procedure should be prepared.
- Design, size and location of the chemical injection facilities is an important factor in order to optimise the operation process (e.g. injection of treated seawater to push more oil out of the reservoir). Therefore, correct system design and customizable location point for injection can avoid the negative effects of over or under dosing chemicals.
- Avoid potential for operational mistakes. In order avoid the possibility of dosing chemicals to the wrong location, avoiding injection of chemical at incorrect rates, prevention of the harmful effect of chemicals (e.g. risk of spillage), a training program for both operational and maintenance personnel should be established. This should familiarize them with all aspects of chemical treatment. A very common problem offshore is that, due to lack of full understanding of the chemical treatment program, incorrect chemicals will be applied in the field. They cause operational problems, increase consumption of chemicals, increase risk of discharge to the sea and in some cases can have a safety implication for the operators.[86]

Although continuous effort is being done to find effective solutions to minimise the use of the chemicals in the field, there are development trends in various cases that usage of chemicals are necessary. Some of these developments are: [24]

- Increased use of subsea developments with long subsea pipelines.
- New developments in deep waters and with floating production units.
- Modern methods in enhanced oil recovery and well work over.
- Production from deep, high pressure and high temperature reservoir.

- Increased production and increased produced water from mature fields.

Therefore, in the oil and gas industry, there is always room for implementation of new technology that can help oil companies to minimise the use of toxic and harmful chemicals and improve the environmental commitment for the industry.

6.5. Alternative Method

In chapter 4, SWIT was introduced as a technology enabler and game changer that allows for total subsea waterflooding. This process is a new water injection technology that treats seawater on the seabed through three techniques with less or no liquid chemical usage prior to injection water down into the reservoir. The results from pilot testing and qualification process have explained SWIT as a system that generates sodium hypochlorite and hydroxyl radicals via electrolysis (patented process) from the naturally occurring elements in seawater. This electrolysis, sufficient reaction time and the nature of SWIT treatment process itself, overcomes the need for many of the liquid chemicals required for a typical topside plant (e.g. filter aids, oxygen scavenger, corrosion inhibitor, antifoam, biocide and scale inhibitors). This represents a significant environmental benefit associated with reducing consumption of chemicals, eliminating the risk of spillage and the long-term effects of hazardous chemicals on the marine environment and entries of toxic compound into the food chain. All of these significant benefits can reduce damage to humans, animals and the ecosystem.

In addition to environmental benefits, minimum manual work with liquid chemicals during the manufacture, transportation and operation process will have positive health and safety impacts for the personnel who supply and operate water treatment plants. Personnel will no longer have close contact with chemicals to transport, handle and dose them into the water treatment system.

It should be noted that SWIT can be built to incorporate liquid chemicals (e.g. biocide and scale inhibitor) if required. However, earlier testing of, biocide shock dosing into the SWIT system (in addition to the electrolysis process to reduce / eliminate reproducing of SRB) proved inconclusive as to the need for biocide dosing at all. The latest test results (phase 4, industrialization project) have shown that there is no need to dose biocide.

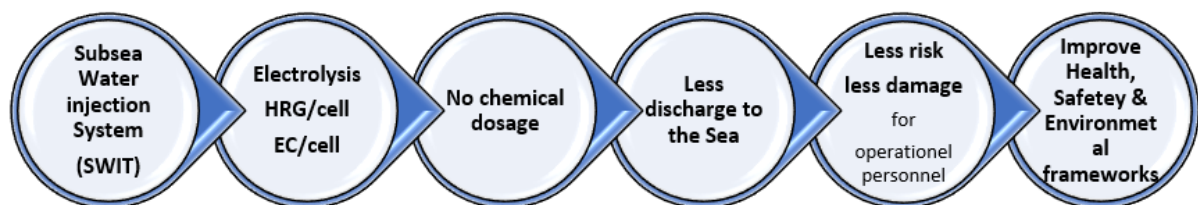


Figure 6.10: Environmental Impact of SWIT with Reducing the Dosage of Chemicals

6.6. Emission to the Air

“Norway should have one of the world’s most ambitious climate policies and that will entail implementing through new and more energy efficiency technology”. [17]

The annual reports from oil and gas installations on the NCS, accounted the emission of CO₂ to the air to be 12 million tonnes [87]. In earlier chapters, gas turbines were introduced as one of the main sources for power and electricity production in offshore installations. These natural gas turbines contain 79% of the emission to the air. According to the other source from Norwegian Pollution Control Authority’s (KLIF), “The Arctic seas are being made rapidly more acidic by CO₂ emission”. It should be concluded that, CO₂ emission, in addition to being well known as a greenhouse gas and causing climate changes, has other harmful effects. One such effect is making the alkaline seas more acidic when it is absorbed from the air (adsorption is faster in cold water). Based on results from monitoring and assessment program, if CO₂ emission stopped now, it would take decades to reduce the harm effect of CO₂ from the both ocean and atmosphere.

This section provides an overview of the following points below:

- Various emission sources to the atmosphere from offshore industry.
- Impact assessment of emission to the air.
- Principle and available methods for reducing pollution.
- Introducing the other significant environmental impact achieved by SWIT technology for power saving and CO₂ consumption.

6.7. Emission Sources from petroleum activities in Norway

Emissions to the air from the petroleum sector mainly consist of exhaust gases from combustion in gas turbines, flaring of gases, diesel exhaust from engines and boilers, combustion of oil and gas in connection with well testing and maintenance. These exhaust gases contain components such as CO₂ and NO_x.

Other environmentally hazardous substances released include nmVOC and methane (CH₄). Gas venting, leaks and evaporation of hydrocarbon gases from storage tanks also causes emission of the above mentioned gases. [74]

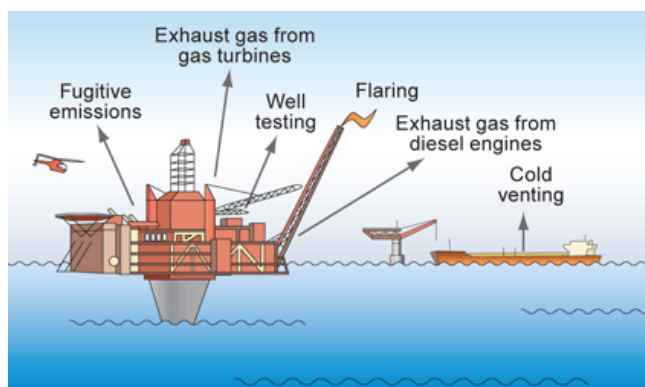


Figure 6.11: Overview of Emission sources from Norwegian Offshore Activities [Courtesy of NPD]

Prior to investigating the environmental impacts due to the emission of gases in NCS, a comparison based on emissions to air in Norway and emissions to air internationally, shows that the Norwegian oil sector already maintains a very high environmental standards compared with other countries that have petroleum activities. Figure 6.12, represents the result of this comparison. The chart units are specified as 100 kg per Sm³ o.e produced for CO₂ and other gases. [74]

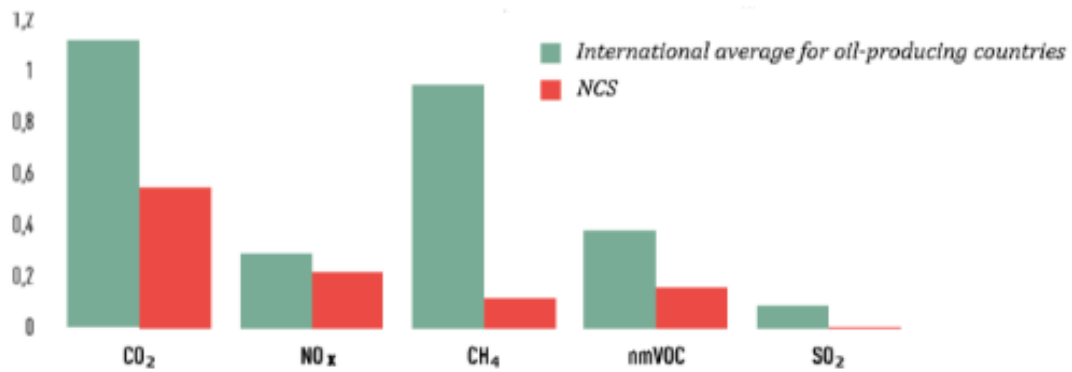


Figure 6.12: Emission to the Air on the NCS compared with the International Average [Adapted from OLF]

6.8. Impact Assessment of Emission to Atmosphere

6.8.1. CO₂ Emission

Emissions of high amounts of CO₂ into the environment is not very favourable news for environmental authorities due to the undesired effect of CO₂ on environment. For instance, high concentration of CO₂ in the air may lead to more CO₂ dissolved in water, which in turn can effects the pH value in lake, sea, and ocean. Reduction of pH in the sea due to the high level of CO₂ has a major effect to the marine ecosystem. For instance, some species such as sea butterflies may be harmed or development of fish eggs will be effected [89]. CO₂ in addition to harm effect on marine life will contributed to the greenhouse effect and caused global warming. CO₂ emission from the oil sectors in Norway account 29% in the total emission of the country based on statistics in 2010 [15]. A large share of CO₂ emission comes from combustion of the gas in the gas turbine on offshore facilities. Gas turbines are used to generate electricity to support different activities on the topside such as pressure building in high-pressure pumps for the injection of seawater into the reservoir or Compression and transportation of gas in order to generation of power in equipment [88]. Figure 6.13 shows CO₂ emission from petroleum's activities.

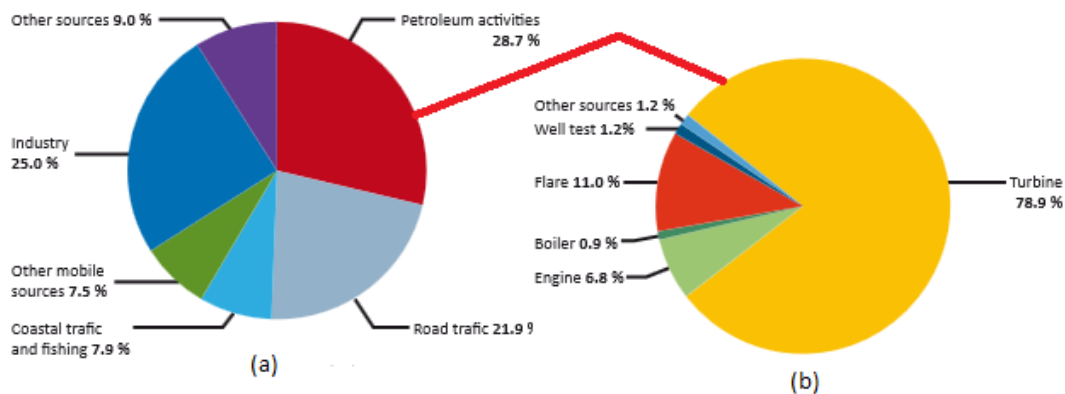


Figure 6.13: (a) Sources of Norwegian Emission of CO₂, (b) CO₂ Emission from Petroleum Activities [Courtesy of NPD]

According to the data, CO₂ emission from the oil activities will be about 12 million tonnes per year. Since Norway always wants to be first when it comes to environmental protection programs, government and environmental authorities cooperate together to introduce policy instruments, improve and support new and more environmentally friendly technologies.

The CO₂ tax and greenhouse gas emission-trading act are two policy instruments in the efforts to reduce the emission of CO₂.

§CO₂ Tax

“The use of oil, gas and diesel in association with petroleum operators on the NCS is subject to the carbon tax under the CO₂ tax act from January 1991. The tax is imposed on the combustion of fuel that produce CO₂ emission, primarily natural gas. As of 1 January 2012, the CO₂ is Nok 0.49 per litre of oil and per standard Sm³ of gas. “[15]

§Greenhouse Gas Emission-Trading Act

“In order to meet the Kyoto Protocol commitment and internal environmental goal, Norway was enacted the greenhouse gas emission trading act in 2005. Based on this agreement, the burning of gas through flaring, beyond what is necessary for safety reason in normal operation is not permitted without authorisation from the ministry of petroleum and Energy”. [15]

6.9. Principle and Methods for Reducing Emission of CO₂

Norwegian oil and gas industry has reported that emission from the offshore industry is expected to increase per unit of energy produced until 2020. Therefore oil companies and environmental authorities have a strong commitment to introduce and develop new technologies to find suitable and environmental solutions that can contribute to reducing the

harm effect of gases into the environment. Some of the methods that already have been investigated / implemented by the oil industry are:

- Power from land and electrification of equipment
- Energy management and energy efficiency
- Combined power
- Storage of CO₂

6.9.1. Power from the shore

In earlier parts, it was discussed that power production by gas turbines on platform facilities have a large influence for emission of CO₂ in NCS. Gas turbines were introduced as aero engine derivatives that generate energy by combustion of gas in a stream of air. The produced gases are passed through turbine blade ‘nozzles’, angled to produce rotational forces which in turn spin an electrical generator to produce electricity. Exhaust gasses are directed back to the atmosphere.

A principal user of the electricity is to provide power to high pressure injection pumps for pumping injection water into the reservoir. Using gas turbine to produce electricity is very common on offshore installations. However, due to the tight weight and space constraints on a platform, operators utilise simple cycle gas turbines that have low energy efficiency (e.g. 30%) and high CO₂ / NO_x emissions.

The idea of electrification is to cut the emission of CO₂ buy utilising electricity that has been generated using more efficient technology on land. This is done by connecting the offshore installation with the onshore electrical grid system via subsea cable. [90]

Outsourcing the power generation to the shore has helped oil companies to manage power and electricity for facilities in a more efficient, cleaner, safer, more economically way and no restrictions associated with space and weight on platform [91][92]. Several fields on NCS have started to get power from the land grid in order to avoid the emission of carbon. Troll A was the first platform and Ormen Lange, Snøhvit, Gjøa and Valhall are other facilities that use power form shore. [15]

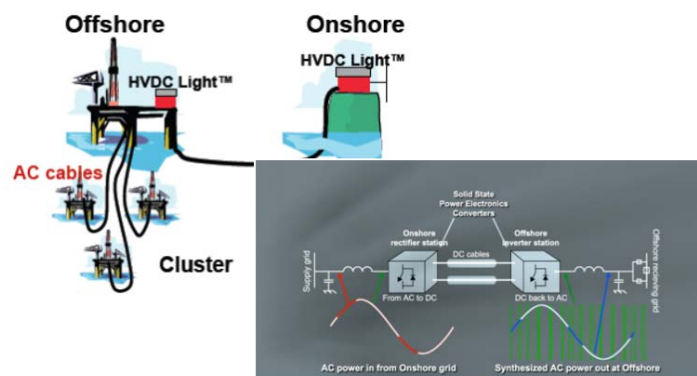


Figure 6.14: Typical Electrical Power Supply from the Grid [91]

6.9.2. Combined Power

Combined cycle power is another example of emission reducing technology that oil companies will use to produce electricity on the platform. The combined power cycle concept is a combination of a gas turbine process and a steam turbine process. The gas turbine exhaust normally exits the gas turbines at 500 °C. This represents a large amount of energy that will be recovered by producing steam under pressure in recovery unit. The steam is then fed to the steam turbine and produces more power. Seawater will be used for cooling down the low-pressure steam from steam turbine outlet, Figure 6.15 The overall result is a steam cycle system which has an increasing level in energy efficiency up to approximately 50% by combined power cycle based on gas turbines [93] [97]. This result will represent a reduction in both fuel consumption and emission of CO₂.

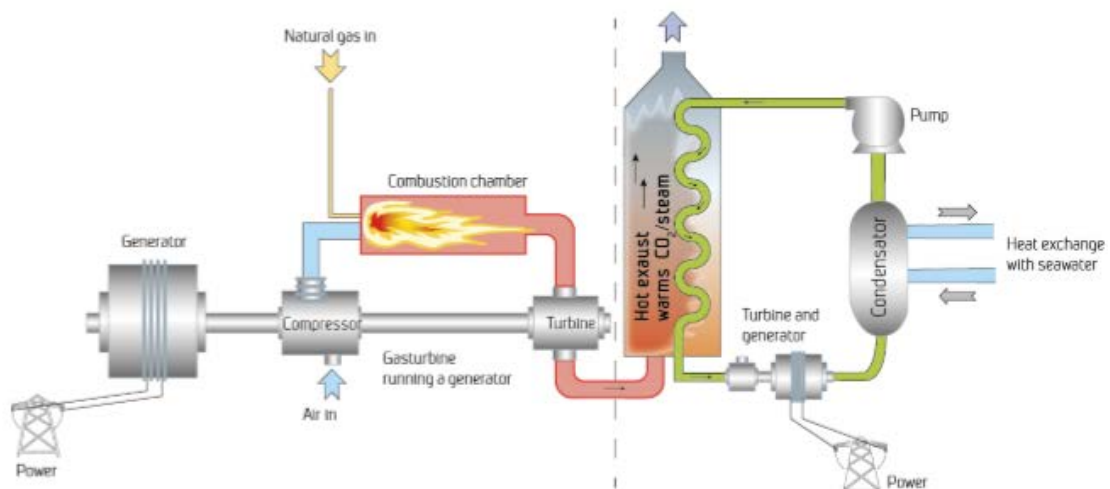


Figure 6.15: Schematic of an Offshore Combined Heat and Power Cycle [97]

Currently, several platforms in NCS are using combined power method to reduce the environmental impacts of CO₂ and NO_x. For instance, Eldfisk field first used the combined power cycle method for water injection system and reduced fuel consumption on the generator sets. This reduction in consumption of gases leads to lower CO₂ emission in tonnes per year. Osberg and Snorre are two other fields that are using combined power on their facilities. [94]

6.9.3. Storage of Carbon (CCS)

The other effective solution to meet environmental regulation associated with reducing CO₂ emission from power plants is capture and then safely store (CCS) it underground so that it cannot go into the atmosphere. The captured CO₂ will be sent through a pipeline to a place where underground formations have capacity to store it safely and permanently. The CO₂ will be pumped via pressure pumped deep more than half a mile down. Finally, the injected site should be monitored to make sure the stored gas does not leak back up the air. [95]

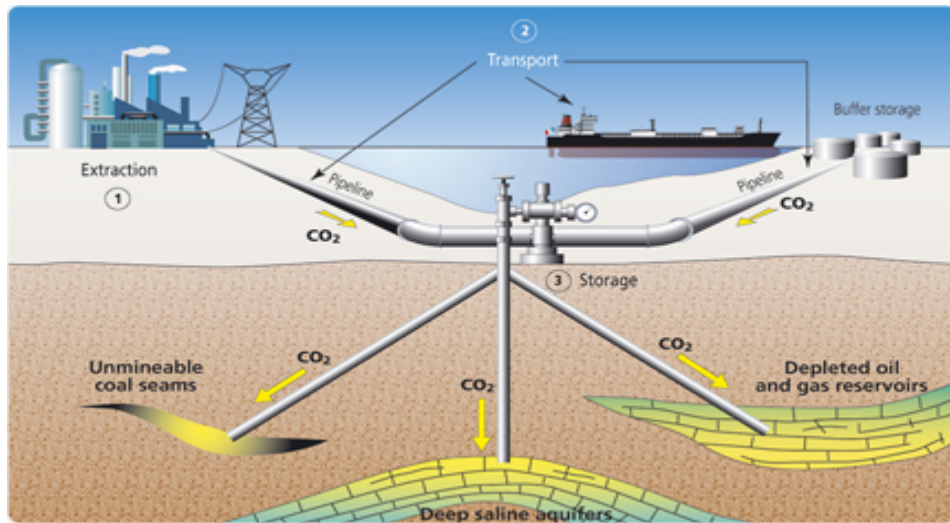


Figure 6.16: Option for CO₂ Storage (CCS) [Adapted from IEA Greenhouse Gas R&D Programme]

Since 1996, a lot of CO₂ have been stored in the Ustria formation on Sleipner filed in the NCS. This is the only facilities in the world where large quantities of CO₂ are stored in the reservoir under the seabed. Figure 6.17 shows CO₂ injection into the Utsira deep saline reservoir. Snøhvit is the other filed that is starting with storing of CO₂ from 2008. [15]

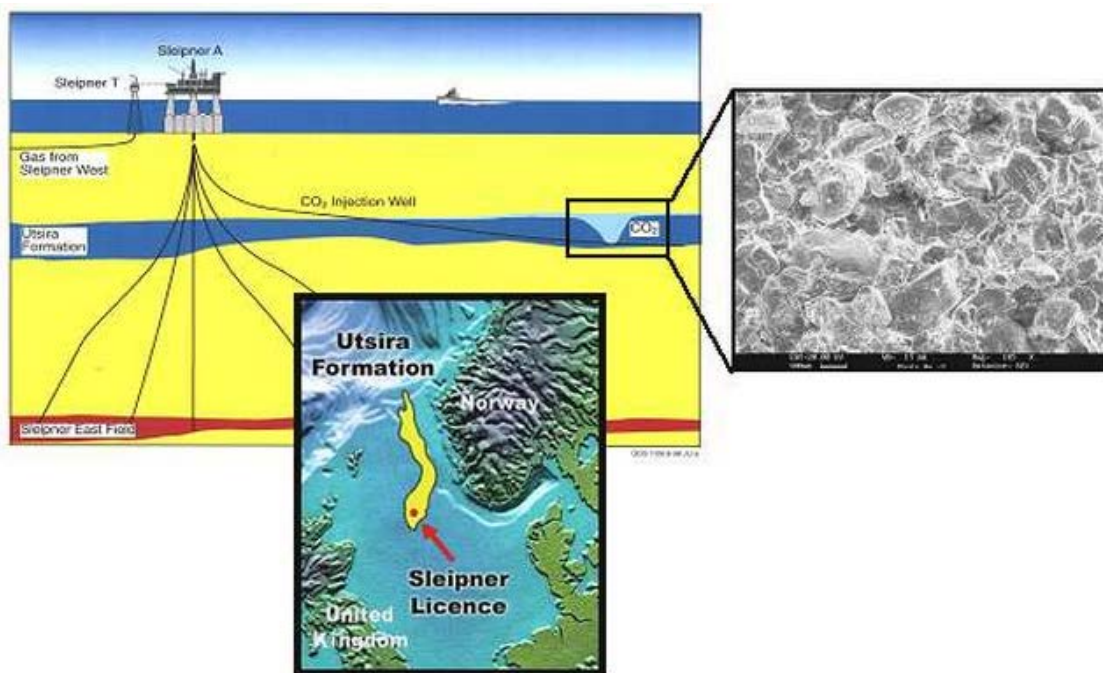


Figure 6.17: CO₂ Storage on Sleipner A Field [Courtesy of Statoil]

In several onshore oil fields worldwide, CO₂ is injected into the reservoir for the purpose of enhance oil recovery (tertiary recovery). Norwegian scientists and authorities have also studied the possibility of injecting CO₂ for enhanced oil recovery on Norwegian shelf (e.g. Draugen field). However, due to the combination of reservoir and supply issues on the mentioned field, oil directorate in Norway has diverted focus to use CO₂ to enhance oil recovery on other oil fields in Norway. [1] [96]

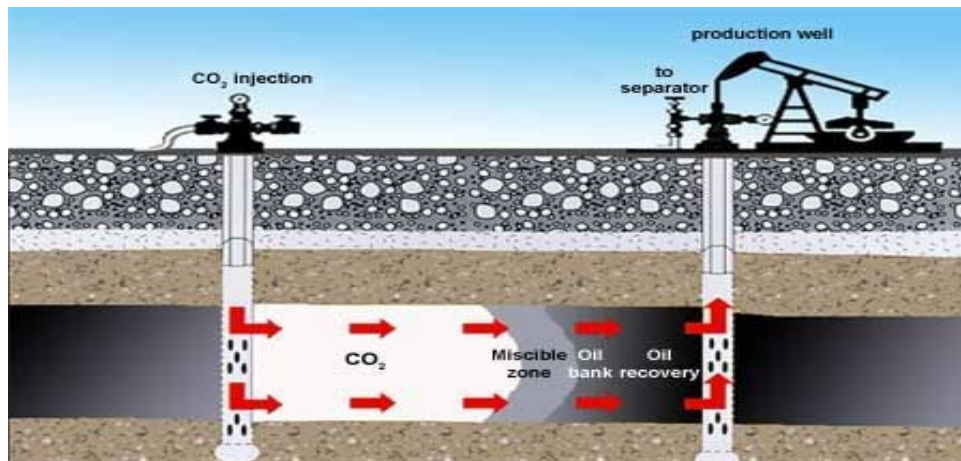


Figure 6.18: Injection of CO₂ for EOR [Courtesy of Wikipedia]

6.9.4. Energy management and Energy efficiency

Energy efficiency and energy management systems are important measures in the world to reduce emissions and require time-to-time system follow up to keep them energy efficient. Such kind of measures depend on the operational pattern, technical design, installed equipment and the facilities infrastructures. In earlier parts, it was mentioned that there are many energy intensive activities for production of the oil and gas on platform that are using for water injection and gas transportation (e.g. compressors and pumps). Since 1991 (after CO₂ tax was introduced in Norway), oil companies (e.g. Statoil) have already developed several environmentally friendly energy management processes in order to optimise and improve energy efficiency in the operations (e.g. the C-Tour separation process). Based on today's technologies, there has been 135,000 tonnes reduction in emission of CO₂ and other greenhouse gasses per year from NCS. However, according to a report from Norwegian Petroleum Directorate (NPD), this reduction could increase 4,6 million tonnes until 2020 by replacement of new equipment (e.g. new pumps that are more energy efficient) or development of alternative technologies. [15]

SWIT can be introduced as an alternative technology for reducing the emission of gases (CO₂ and NO_x) into the air by saving power.

In order to verify how much power can be saved, the Gulfaks field has been used as an example and a comparison been made between using water injected via a topsides system and injecting via a subsea system (using SWIT). The results obtained from this comparison are given later in Chapter 7. However, prior to illustrating how much power saving subsea waterflooding can attain, the following is a brief explanation about emission of other gases and the effect of them on the environment.



Figure 6.19: Environmental Impact of SWIT based on Less Power Consumption

6.10. NO_x Emission

NO_x is emitted from the same sources as CO₂. The emissions from gas combustions in turbines, flaring of gas and diesel consumption on the platform are the key emission sources also for NO_x. Emission of NO_x from power generation contributes to a range of human, health and environment concerns. The environmental effects of NO_x emissions are listed below [98] [99]:

- NO_x emission react in the atmosphere to form acidic compounds, and then these acidic compounds (e.g. nitric acid) is deposited on the earth surface and acidify lakes and streams. The results of acidification and chemical changes in the lakes, lead to difficult situations for fish and other fauna to grow, survive and reproduce. Acid deposition (e.g. acid rain) can also affect forest ecosystems (e.g. changing the chemistry of the soils compounds).
- The other impact of NO_x emission is reaction with volatile organic compound (VOC) in the atmosphere in the presence of sunlight to form ground level ozone. Damages to health, crops and buildings are the major results of ground level ozone formation.
- Acid rain has a high potential to damage buildings and structures made of limestone and metalwork. These materials are very sensitive to acid deposition and the weathering's rate will increase due to the acid particles in the air.

The Norwegian environmental authorities have accounted 27% of NO_x emission in Norway comes from oil sectors [15]. The emission of NO_x per produced oil equivalent have risen slightly per year due to the increasing energy requiring activities in NCS. In order to keep the level of NO_x emission low, environmental authorities have conducted tax policy. Environmental regulations and oil companies have improved the use of new technology for reducing emission. Figure 6.20 Shows emission sources for NO_x in NCS.

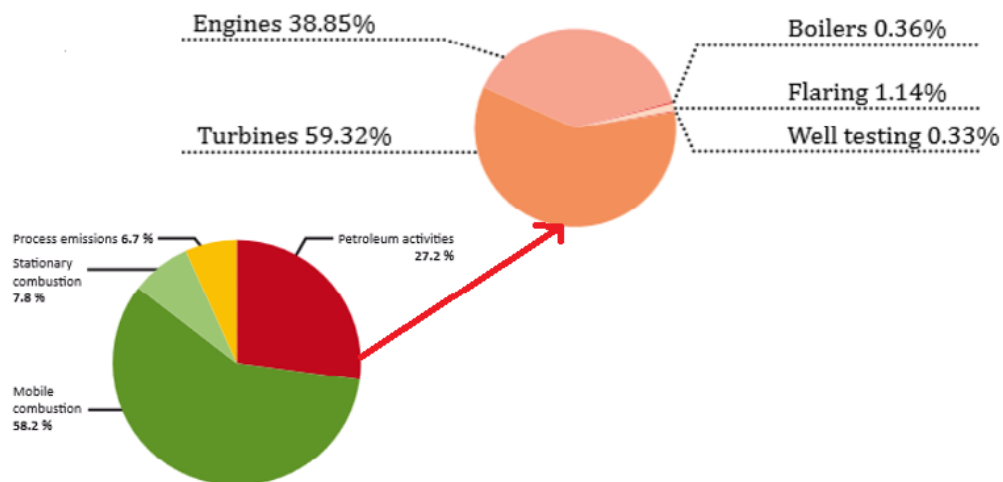


Figure 6.20: Historical Development of overall NO_x Emission (Tonnes) in NCS [74]

§NO_x Tax

“The Storting approved a tax on emissions of NO_x in 2006. The tax is direct towards emission from mainland activities and includes emission from large units within shipping, aviation, land based activity and continental shelf. Within the petroleum’s sector, the tax covers total emission from large gas turbines and from flaring”. [15]

6.11. Method for Reducing Emission of NO_x

6.11.1. Low NO_x Burner

Low NO_x burner technology (turbines) have been installed on petroleum’s facilities to reduce emission of NO_x. The structure of this burner is based on to control fuel and air mixing at each burners in order to create large flames. Once the flames are large, peak flame temperature is thereby reduced and results in less NO_x emission. [100]

Injection of steam or atomised water is another option that can reduce NO_x emissions by reducing temperatures at the outlet from turbine combustion chambers. However, this technology is not commonly used offshore, because of the quantities of demineralised water required and difficulties in droplet impingement on the turbine blades. [74]

6.12. NmVOC Emission

Non-methane volatile organic compound is the other pollution source from the oil industry. This emission primary comes from loading and storage of crude oil and contains harmful effects on environment. Hazardous effect of nmVOC are:

- Formation of ground ozone,
- Contribution to the greenhouse effect
- Respiratory tract damages on human and animals due to the direct exposure to nmVOC.

Storage place for loading of oil plays an important role for emission of VOC because the content of volatile gases varies from field to field. If the field has floating storage facilities, the risk for emission of VOC will increase, because floating storage facilities entails emission between production and storage. However, the fields with storage place on the deck (platform) has lower VOC emission (e.g. Statfjord, Gulfaks and Drugen field). The technology for recovering nmVOC available to storage vessel and tankers is today's solution for reducing emission from loading by 70%. [15] [74]

Environmental authorities in order to optimize strategies, methods and regulations for emission reduction according to health, safety and environmental benefits, have also developed an integrated methodical modelling tool (Environmental Impact Factor for Emission to the Air). Datasets and information's from acidification of surface water and soil, nutrient effect on terrestrial ecosystems and damages from ozone concentrations will be estimated by EIF-Air software model. More information about EIF-Air approach and calculation method is available on reference [101].

7. A CASE STUDY

Based on all background information in the previous chapters, the most important and interesting question for this thesis is:

- ❖ How much can subsea waterflooding (using the SWIT system) help improve the effects on the environment as compared to today's topsides methods?

In order to illustrate this, waterflooding from a typical North Sea offshore oilfield has been assembled. The flow rate for this imaginary field has been based on the Gullfaks B platform in the NCS. Typical topside water treatment methods are compared with a possible subsea waterflooding method.

The following comparisons have been made:-

- Power Consumption
- Chemical Usage
- Weight and Space Issues
- Reduced Offshore Manning

A detailed power consumption comparison has been conducted along with a detailed chemical consumption comparison. Estimates from generic data are used to compare the weight and manning levels.

Gullfaks General Information

Gullfaks is an oil field located in the Tampen area in the north part of the North Sea. The water depth in this area is 130-220 meters. The field has been developed in three facilities (Gulfaks A, B & C) with concrete bases and steel topsides. Gullfaks B consists of a simplified processing plant with integrated WI facility. WI is the main secondary recovery strategy for Gullfaks B. It should be noted that Statoil has applied other strategies such as gas injection and water/alternating gas injection (WAG) to recover the required pressure inside the reservoir for recovery of oil. [15] [102]

7.1. Power Comparison

Tables below introduce the evaluations from Gulfaks B and SWIT. The data on tables consists of consumed energy (MW) and percentage of saving power with SWIT.

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Table 7.1: Injection parameters for Gullfaks B

Water Injection Gullfaks B		
Total injection flowrate	2917	m ³ /h
Water depth	143	M
Depth of reservoir	1900	M
Pressure required at perforation	384	Bar
Injection flowrate/well	133	m ³ /h




Table 7.2: Energy consumption for WI equipment on Topside

Pressure Loss / Gain Table vs Electrical Power Consumers			
Pressure Boosters (Pumps)		Pressure (bar)	Power (MW)
Lift pumps power consumption in MW (Incl. Pump efficiencies, electrical efficiencies)		21,2	2,41
Booster pumps power consumption in MW (Incl. Pump efficiencies, electrical efficiencies)		15	1,71
Injection pumps power consumption in MW (Incl. Pump efficiencies, electrical efficiencies)		236	26,84
Vacuum pumps /other water injection users in MW (Incl. Pump efficiencies, electrical efficiencies)			0,41
Static head from injection pump elevation to reservoir perforations		213,5	
Topside Pressure Losers	Effective length (m)		
Treatment Equipment pressure losses = (Lift pump power)		21,2=3,5+17,7	
Friction losses in pipework from deaerator to injection manifold-10" (2 manifolds with no bends or fittings)	100	5	
Friction losses in well tubular from injection manifold to reservoir perforations (depth + deviation)	2102+1500	75	
Total		384,5	31,37

Table 7.3: Energy consumption for subsea seawater treatment system (SWIT)

Subsea Pressure Gainer (Power Consumer)			
Pump		Pressure (bar)	Power (MW)
Injection pump power consumption in MW (incl. Pump efficiencies, electrical efficiencies, cable losses)		228,5	27,43
Static head from sea level to reservoir perforations		210	
Subsea pressure Losers	Effective length (m)		
Friction losses in pipework from injection pump to reservoir perforations (depth + deviation)	2102+500	54	
Total pressure		384,5	27,43

Table 7.4: Power saving results

Comparison Results	
Power Saving with using subsea water injection system (MW)	3,94
Typical power saving for SWIT in comparison with topside WI (%)	12,56

	Active addition to pressure
	Active reduction to pressure
	No effect on injection pressure

The results from power saving comparison between a topsides WI system on Gullfaks B and a subsea water injection system indicates that ca.4 MW power (13%) power savings can be made. This is to inject identical volumes of water to the same perforations in the reservoir. Table 7.4

A large proportion of this saving is due to not having to lift seawater to a topsides facility and push it through a large seawater treatment plant. SWIT requires very low power usage (ca. 4 kW) for its electrolysis processes (EC cells and HRG cells) and therefore does not feature in the MW calculations above.

CO₂ and NO_x reduction leads to lower greenhouse gas effect into the air and the result is less impact on human, marine species and ecosystem.

7.2. Chemical Consumption Comparison

Topsides

The following Topsides Water Treatment plant is assumed:-

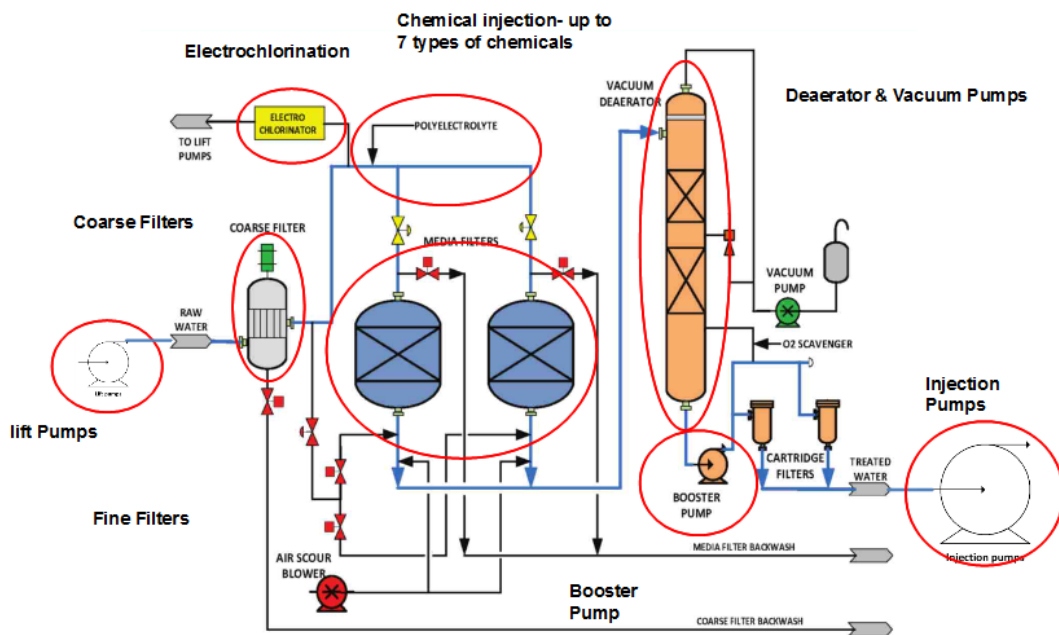


Figure 7.1: Typical Topside Water Injection System [Courtesy of Prosep]

Table 7.5 gives typical chemical dose rates as discussed in Chapter 3 of this document

Table 7.5: Typical Topside chemical dose rates

WI Flowrate			
400000	bbl/d		
2917	m ³ /h		
Chemical	Dose rate	Consumption	Consumption
	mg/l	m ³ /week	m ³ /year
Filter aid 1	6	2.94	153
Filter aid 2	6	2.94	153
Antifoam	6	2.94	153
Oxygen Scavenger	20	9.80	510
Corrosion inhibitor	20	9.80	510
Biocide (shock dosed)	1000	11.67	607
Scale Inhibitor	20	9.80	510
Total			2594

Subsea Waterflooding

For a SWIT treatment unit it is assumed that chemical dosing will consist of:-

- Biocide: needed as seen in the full scale pilot testing i.e. ca 2000 mg/l for 15 mins once / month
- Scale inhibitor: needed in the same proportions as a topsides treatment plant; 20mg/l continuous



Figure 7.2: SWIT treatment System [Courtesy of Seabox]

Table 7.6: SWIT Treatment System

WI Flowrate			
400000	bbl/d		
2917	m ³ /h		
Chemical	Dose rate	Consumption	Consumption
	mg/l	m ³ /week	m ³ /year
Filter aid 1	0	0.00	0
Filter aid 2	0	0.00	0
Antifoam	0	0.00	0
Oxygen Scavenger	0	0.00	0
Corrosion inhibitor	0	0.00	0
Biocide (shock dosed)	1000	0.18	9
Scale Inhibitor	20	9.80	510
Total			519

The results show a considerable saving in chemical consumption when using subsea water injection. This amounts to over 2000 m³/ year of chemicals.

Another factor to take into consideration is the logistical aspects of getting an additional 2000 m³ of liquid chemicals to the offshore installation every year for a topsides WI plant. Significant issues are:-

- The manufacture of the chemicals themselves
- Tote (storage) tank loading and transportation to an oil companies offshore supply base (Tote tank volume is typically 3m³ = 666 tote tanks/year for 2000 m³ of chemicals)
- Loading onto a supply boat and transportation offshore
- Unloading and storage of tote tanks offshore
- Transfer of the chemicals to the storage tanks on the Chemical injection skids themselves
- Dose rate regulation and control of each of the chemical injection pump systems

7.3. Weight Comparison

Topsides Water Injection Plant

Topsides weight for a 400,000 bbl/d plant is in the region of 1200 tonnes

(Added to this is the weight of water contained in the pipework and vessels which adds a considerable topsides weight to be supported)

A good estimate is that for every tonne of topsides weight two tonnes of support structure weight is needed. ; 4000 tonnes

Total weight implications for a 400,000 bbl/d WI plant is therefore 5200 tonnes

Subsea Water Injection Plant

Multiples of Standard SWIT 40,000 bbl/d units are assumed (10 off) although for this flow rate, larger SWIT units may be more economical.

A 40,000 bbl/d SWIT weigh ca 40 tonnes

Ten of these units would therefore weigh ca 400 tonnes

Note: these figures do not include for the injection pump systems, which are estimated to be another 400 tonnes in total weight.

So total weight for 10 off Subsea injection systems (400,000 bbl/d) would be in the region of 1000 tonnes.

7.4. Manning Level Comparison

Estimations have been performed using a field development estimating tool (Que\$tor¹⁷) This shows that manning levels differentials for a platform with 160,000 bbl/d water injection plant to be 52 men. The same platform without WI will require 46 men. Therefore direct manning levels for a 160,000 bbl/d WI plant are estimated to be 6 men on a continuous basis. This includes for operation and maintenance work.

For a subsea water WI injection system the principle work is associated with scheduled maintenance equipment retrieval and reinstallation (e.g. once every 5 years.) However, previous cost estimating has included for 2 working days every 2 years for equipment inspection and retrieval. (not including mobilisation /demobilisation issues of a light intervention with DP vessels).

HSE is a factor that is also affected. Equipment installed at the seabed is designed for a longer service interval and has a higher reliability. Fewer services have to be provided and the service is performed onshore in a safe environment specific for service. Service personnel do not need to go offshore and are less exposed to chemical spillages.

Each offshore service personnel also need:-

- Helicopter transportation to / from the platform
- Food and accommodation while offshore
- Safety infrastructure and support team
- Tools and equipment to be able to perform work tasks
- Every position has back up positions onshore

¹⁷ Que\$tor is an industry software tool for capital and operating cost estimation (CAPEX & OPEX).

8. CONCLUSIONS

This thesis has described the theory of waterflooding for IOR purposes and the relevance of seawater quality to common reservoir issues. In doing so, a typical topside seawater injection system has been compared to recently developed technology for seawater treatment and injection from the seabed (using the SWIT system). A chapter is included that gives a broad base understanding of environmental impact factors and a case study has been established to investigate how the environmental implications can map out in a real life scenario.

The objective of this thesis is to investigate the environmental aspects of the subsea waterflooding technology in line with the role of HSE within oil companies' framework. Comparisons have therefore been made on health, environmental and safety factors such as energy consumption (Power), chemical usage and offshore manning levels.

8.1. Increased Oil Recovery Issues

Water injection was developed from the onshore field applications of the 1950's to the offshore systems of the 1970's. Injection of processed seawater from topside is by far the most used method of increasing oil recovery from an oil reservoir in both the NCS and other oil producing countries. However, water injection treatment facilities and injection pump occupy space and present weight problems on the platform. Therefore, the demand in development and implementation of water treatment technologies that, gives more freedom from topsides restrictions (e.g. weight/ space) and can offer less impact on environment are becoming increasingly more sought after in the oil industry.

SWIT is a technology that enables the movement of seawater from topside to the seabed and removes constraints such as capacity, weight, space.

The main advantage of subsea waterflooding in comparison with topside waterflooding technology from a reservoir engineering point of view, is the high level of flexibility afforded. Water Injection is totally decoupled from the platform activities and a reservoir engineer is given freedom to injection of as much water as required at any stage of fields life time. This leads to more oil efficient recovery at lower energy usages.

8.2. Water Quality Issues

In most cases the injection of untreated seawater that contains particles and bacteria is unacceptable as raw seawater injection can lead to blocking the reservoir and also reservoir souring. Microbiological activity can also lead to microbial induced corrosion (MIC).

The SWIT system has proven to give quite remarkable results for seawater disinfection without the need to inject liquid chemicals. Reducing the normal probability of SRB and GAB inside the well and in the near well bore area. Removal of solids is also achieved, tests have shown solids removal down to 99 % of 15 micron particles to be possible.

It can be concluded from the previous chapters that SWIT is just as capable of providing good quality water for waterflood purposes as a topsides treatment plant (if not better) certainly in the field of preventing biological activity.

8.3. Power and Emissions



SWIT operation is designed to be all electric in operation. One of the areas where the SWIT water treatment system contains significant levels of innovation is the SWIT's power system. There is no moving parts for SWIT and the connection between SWIT and Topside will be provided via electrical cables. These cables provide the power requirement of electrical for sterilisation of seawater via electrolysis process (EC cell and HRG).

The results from power saving comparison between a topsides WI system (e.g. Gullfaks B) and a subsea water injection system (Chapter 7) indicates that ca.4 MW power (13%) power savings can be made. This is to inject identical volumes of water to the same perforations in the reservoir. A large portion of this saving is due to not having to lift seawater up to a platform, perform treatment, boost pressure and distribute via long deviated wells or subsea pipelines.

SWIT requires very low power usage (ca. 4 kW) for its electrolysis processes (EC cells and HRG cells) and therefore does not feature in the MW calculations.

CO₂ and NO_x reduction leads to lower greenhouse gas effect into the air and the result is less impact on human, marine species and ecosystem.

8.4. Chemical Usage



Topsides treatment involves using large quantities of chemicals such as biocides, oxygen scavenger, antifoam, filter aids (e.g. flocculants, coagulant), scale inhibitors, and corrosion inhibitors. The test results and chemical assessment project (CHARM) have reported that some of the chemicals used in a topsides WI treatment plant has impact on HSE

SWIT generates its own chemicals (sodium hypochlorite and hydroxyl radicals) via electrolysis of naturally occurring elements in seawater. This electrolysis and the nature of the SWIT treatment process itself overcome the need for many of the chemicals required for a topside plant.

The chemical consumption comparison between Topside treatment system and SWIT has shown that Topside treatment system uses 2594 m³ of chemicals per year. By comparison, the chemical consumption of SWIT system is 519 m³/year. This represents significant saving in chemical consumption per year (2000 m³/year)

From an HSE aspect, less chemical usage represent significant health and safety advantages for offshore and operational personnel that have directly contact with chemicals to transport, handle and dosing of them into the chemical injection pumps. Once less chemical are used, the risk of spillage and harmful effect of toxic chemicals will also be reduced.

8.5. Weight and Space Issues

A traditional solution for cleaning water on topside, uses very large, heavy and space consuming equipment. Topsides weight for a 400,000 bbl/d equipment treatment plant alone

would be in the region of 1,200 Te. When this equipment and pipework system is filled with seawater the weight to be supported by a platform jacket is significantly larger. Seabox estimation programs indicate that a further 4000 Te in jacket support steel would also be required, giving a total equipment and support structure weight in the region of 5,200 Te.

The SWIT system offers a much simpler treatment solution which lies on the seabed and therefore does not need supporting with a jacket. Seabox estimation programs indicate that total subsea weight for a same capacity water treatment and injection system would be in the region of 1000 Te.

4,200 Te weight savings (mainly in steel fabrication) has a lot of implications in other environmental aspects such as: Less steel production, less steelwork construction, less equipment (lift pumps, fine filters, coarse filter, vacuum towers, chemical injection booster pumps and high-pressure injection manifolds). All of this will translate into improved environmental consequences.

In addition SWIT will not occupy any space on the platform. Therefore, there will be more space for other (best available technology) production equipment (e.g. better produced water separation units / turbine waste heat recovery / combined cycle technology) which will enable other environmental benefits – as described in Chapter 6 (or a smaller platform).

8.6. Reduced Offshore Manning

Being subsea, SWIT requires less manning to operate than a topside treatment plant. Using the Seabox estimating program it is estimated that 6 men are required to operate, maintain, and provide logistical back up to keep a topsides WI treatment plant running.

For a subsea water injection system the principle work is associated with scheduled maintenance equipment retrieval and reinstallations once every 5 years.

8.7. Future Development

Further developments for SWIT that have been started for testing in Oslo fjord at NIVA water research centre in 2012 was combination of subsea membrane technology and SWIT in order to produce low saline and low sulphate water. The data and results from tests protocol can open the next step of innovation for this new and unproven technology to produce “tailor made” water and even fresh water much more effective than with the current technology.

It is believed that the findings of this thesis can be very central for oil industries in their quest for new technologies that can increase oil recovery, meet environmental regulations and improve the environmental framework strategies.

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APPENDIX A



Agreement concerning Restricted Access to Bachelor's and Master's Thesis

between

.....
.....
Studentent's name *Anita Aghabalaee* and Date of birth *07.02.85*

.....
.....
Fakulty supervisor *Torleiv Bilstad* and Department *Faculty of science and technology*

.....
.....
Company name *SEASOX* and Company contact person *David Pinchin*

concerning bachelor or master thesis titled:

.....
.....
Environmental Aspects with Subsea water Treatment Technology (SWIT)

.....
This is an unofficial translation. Where there are linguistic differences the Norwegian contract version is the official version and shall be used to settle disputes.

Faculty of Science and Technology
Decision made by the Dean October 30th 2009

APPENDIX A



1 RIGHTS AND PUBLISHING

- 1.1 Students own the copyright to their theses (cf. Copyright Act of May 12, 1961, no. 2, § 2). Students have the right to publish their results in scientific journals, seminars, conferences, popular articles, etc. However, the students must credit the company and UiS in their resitations. Restrictions concerning this right must be stated in this agreement (cf. 1.3).
- 1.2 The thesis with all addenda (drawings, models, instruments, cd, e.c) handed in for evaluation is the property of the UiS. It may be used without compensation by UiS for purposes of teaching and research. In such cases UiS must credit the student(s) (cf. Copyright Act § 3) and the contribution of company.
- 1.3 Theses that have been handed in, will normally be open to the the public. Upon application from the company the UiS can delay publication for two years, maximum five years. Objection against restricted access and rejection of the same will be dealt with according to the Civil Service Administration Act regulations concerning resolutions.

The thesis has been given restricted access for 5 years

After restricted access has been accorded, the student(s) and UiS must observe confidentiality during the period the thesis has been given classified status.

The requirement of classification does not apply to information

- a) that was available when the thesis was handed in
- b) was known by UiS or the student at the time
- c) was legally received from a third party without any agreement of confidentiality
- d) was developed by UiS independently of received information
- e) that UiS as a public institution has a duty to relinquish
- f) that, because of elapsed time or other factors, it is evident that the reasons for upholding classification are no longer present

2 DISPUTES

Disagreement concerning the interpretation of this agreement or situations that arise from the same, will be tried solved by negotiations. If agreement is not achieved within 1 – one – month after negotiations have been requested, the dispute will be settled by arbitration in Norway according to the Arbitration Act of 14.05.2004. Stavanger Municipal Court will be the guardian court of law if the parties cannot reach agreement about another court. If nothing else is stated in special conditions, Norwegian law remains the basis for the solution of disputes. That a dispute is up for arbitration, does not exempt the parties from fulfilling their obligations according to the contract.

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APPENDIX A



3 AGREEMENT FORM AND SIGNATURES

This agreement has been signed in three copies, of which the student(s) and the company receive one copy each.

Stavanger, 19 / 04 20..13

Signature... (place): 22 / 04 20..13

Student(s):

For the company: (SARBOX AS)

name: Anita Ashabalaee

name: David Porsman

name:

title: C.T.O.

name:

Anita Ashabalaee
signature



signature

signature

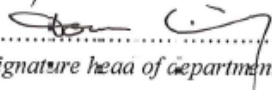
signature

Note

An application must be attached to the agreement in which it must be made plausible that publication will do considerable harm.

The agreement must be signed by the student(s) and the company in three copies before UiS will process it.

Stavanger, 23 / 5 20..13

For UiS: 
signature head of department/dean

name in block letters: TORE WILG

(Note: When the thesis has been given classified status for two years, the head of department must sign the agreement. When the thesis has given classification beyond that period, the dean must sign the agreement.

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