Offshore Industry Series

Background Document concerning Techniques for the Management of Produced Water from Offshore Installations

OSPAR Commission

2002

The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

La Convention pour la protection du milieu marin de l'Atlantique du Nord-Est, dite Convention OSPAR, a été ouverte à la signature à la réunion ministérielle des anciennes Commissions d'Oslo et de Paris, à Paris le 22 septembre 1992. La Convention est entrée en vigueur le 25 mars 1998. La Convention a été ratifiée par l'Allemagne, la Belgique, le Danemark, la Finlande, la France, l'Irlande, l'Islande, le Luxembourg, la Norvège, les Pays-Bas, le Portugal, le Royaume-Uni de Grande Bretagne et d'Irlande du Nord, la Suède et la Suisse et approuvée par la Communauté européenne et l'Espagne.

ISBN 0 946956 87 1

contents

Executive Summary

This background document is related to OSPAR Recommendation 2001/1 for the Management of Produced Water from Offshore Installations. It contains brief descriptions of principles, basic elements and operational aspects of techniques which may be applied on offshore installations for the treatment of produced water.

An overview of various techniques for the removal of heavy metals, dissolved oil, dispersed oil and offshore chemicals from produced water is presented in Table 1. For a number of techniques that are currently available or emerging for the treatment of produced water from offshore oil and gas installations as part of a BAT/BEP solution, fact sheets are presented. A short description of principles, basic elements, operational aspects and other factors relating to each type of these systems is presented in the tables A – 1 to C – 14. An overview of the techniques for which fact sheets have been prepared is presented in Table 2. This table contains examples of techniques that are currently available or emerging for the treatment of produced water from offshore oil and gas installations as part of a BAT/BEP solution.

Although the physical and chemical principles of techniques described are generally applicable, the technical and economical features mentioned in the current version of this background document draw mainly on experience principally of operations in the southern North Sea which is predominantly a gas province with some oil and with relatively low volumes of produced water. The validity of the cost and technical data is therefore limited, and this should be taken into account when evaluating the applicability of techniques in other areas and in other circumstances.

It is the intention that this background document be revised to include data on applicability of techniques for a wider scope of offshore oil and gas (e.g. large oil fields in the central North Sea). Furthermore this background document is intended to be updated regularly in order to allow for the inclusion of descriptions of new techniques when these emerge.

Récapitulatif

Le présent document de fond concerne la Recommandation OSPAR 2001/1, sur la gestion de l'eau de production des installations offshore. Il décrit brièvement les principes, les éléments de base et les aspects opérationnels des techniques susceptibles d'être appliquées à bord des installations offshore pour le traitement de l'eau de production.

Une vue d'ensemble des diverses techniques d'élimination des métaux lourds, des hydrocarbures dissous, des hydrocarbures dispersés et des produits chimiques d'offshore provenant de l'eau de production est présentée au tableau 1. Pour plusieurs des techniques disponibles ou émergentes pour le traitement de l'eau de production des installations pétrolières et gazières en offshore, à titre de partie intégrante des BAT/BEP, des fiches de caractéristiques sont présentées. Une brève description des principes, des éléments de base, des aspects opérationnels et d'autres facteurs concernant chacun des types de ces systèmes est donnée aux tableaux A – 1 à C – 14. Une synthèse des techniques au titre desquelles des fiches de caractéristiques ont été dressées est présentée au tableau 2. Ce tableau donne des exemples des techniques disponibles ou émergentes pour le traitement de l'eau de production des installations pétrolières et gazières en offshore, à titre de partie intégrante des BAT/BEP.

Bien que les principes physico-chimiques des techniques décrites soient généralement applicables, les caractéristiques techniques et économiques mentionnées dans la version actuelle du présent document de fond sont pour l'essentiel fondées sur l'expérience principalement acquise dans les opérations dans le sud de la mer du Nord, région principalement productrice de gaz, avec un peu de pétrole et des volumes relativement faibles d'eau de production. De ce fait même, la validité des données de coût et des données techniques est limitée, ce point devant être pris en compte lorsque l'on juge de l'applicabilité des techniques dans d'autres régions et dans d'autres circonstances.

Il est prévu de revenir sur ce document de fond pour y inclure des renseignements sur l'applicabilité des techniques dans d'autres régions pétrolières et gazières en offshore (par exemple, les grands champs pétrolifères du centre de la mer du Nord). De plus, il est prévu d'actualiser régulièrement le présent document de fond afin d'y intégrer des descriptions des nouvelles techniques au fur et à mesure qu'elles apparaîtront.

1. Introduction

The planning and management of operations at offshore installations should be in accordance with the integrated approach. A "tailor-made" combination of BAT and BEP should be applied for produced water management on offshore oil and gas installations in order to prevent and minimise pollution by oil and other substances as much as reasonably achievable. Whereas BAT is mainly focusing at application of techniques, BEP focuses on environmental control measures and strategies (management options). Reference is made to the definition of BAT and BEP in Appendix 1 of the OSPAR Convention.

Produced water treatment techniques may either be based on the reduction of volume of produced water or on the reduction of the concentration of substances in produced water. Furthermore, techniques may be applicable for oil and/or gas installations. Some techniques are well established and may be considered as current BAT, or present techniques. Some systems cannot be regarded as BAT as such, but may form part of a BAT solution when applied in a series of treatment systems. Other systems should be considered as emerging techniques, which are candidates for inclusion in the list of techniques that may form part of BAT solutions for produced water in the future.

The definition of BAT, including a mechanism of how a set of processes, facilities and methods of operation should be evaluated with a view to determine whether these constitute the best available techniques in general or in individual cases, is described in Appendix 1 of the OSPAR Convention.

An overview of various techniques which may be applied for the treatment of (produced) water is presented in Table 1. Not all these techniques are currently suitable for the treatment of produced water on offshore installations, for various reasons. For a number of techniques that are currently available or emerging for the treatment of produced water from offshore oil and gas installations as part of a BAT/BEP solution, fact sheets are presented in the tables A – 1 to C - 14. An overview of the techniques for which fact sheets have been prepared is presented in Table 2. This table contains examples of techniques that are currently available or emerging for the treatment of produced water from offshore oil and gas installations as part of a BAT/BEP solution.

The cost and technical data in tables A – 1 to C – 14 of this background document draw mainly on experience principally of operations in the southern North Sea which is predominantly a gas province with some oil and with relatively low volumes of produced water. Estimates of performance and cost (see Annex 1) are based on model scenarios that reflect operations in this basin and are unlikely to be applicable rigorously in other areas. It is the intention that the tables in this background document be revised to include data on the applicability of techniques for a wider scope of offshore oil and gas (e.g. large oil fields in the central North Sea), where applicable. Furthermore new tables on techniques mentioned in table 1, and not mentioned in tables A – 1 to C – 14 will be added in this background document in future updates of this document. The process of continuous updating will also allow for inclusion of (new) techniques when these emerge.

In view of the fact that the characteristics of produced water can be different from one installation to another and can vary widely both in the short and the long term at a single installation, the applicability of each type of system, or combination of systems, on a platform can only be evaluated on a case-by-case basis. Factors influencing the applicability of a system include, amongst other factors:

- the amount of produced water, which may increase in the course of the lifetime of an installation;
- the characteristics of the produced water flow;
- available deck space; and
- the need for and extent of retrofitting.

Moreover, techniques have intrinsic limitations and limitations relating to specific circumstances in which an offshore installation operates. The techniques in the tables are available techniques. A combination of techniques, selected on the basis of specific conditions and other factors, could form a "best available solution for the treatment of produced water" on an offshore installation or "best available package".

Irrespective of which method is considered and evaluated, it should be realised that the success of any method is dependent, amongst others, on the local environment in which it will be operated. The local reservoir conditions as well as the local operational conditions may strongly influence the effectiveness and operability of the method in question e.g. it cannot be concluded that a method, which has been operated successfully at one installation, may achieve the same results at another location.

Motion of floating installations may render gravity-separation devices less efficient under extreme conditions.

Physical/chemical aspects have not been taken into account: oil-water emulsions may break down more or less easily, depending on the composition of the oil and water. Again, this underlines the importance of case-by-case evaluations and the selection of treatment techniques for specific platforms should take this feature into account.

It is noted that the rows in the tables concerning the indication of costs of each technique contain estimates for the treatment of the indicated flows of produced water under certain circumstances only. Furthermore, it should be noted that the indicated (relative) costs stem from calculations based on pre-defined model situations. The definition of the model situations is applicable to a limited amount of offshore operations, it should be taken into account that these figures could vary from region to region or even from country to country. An evaluation of costs of application of a certain (series of) treatment technique(s) on a specific offshore installation, should be made on a case-by-case basis.

Cross-media effects and other impacts should also be considered when evaluating a system. Issues that may be covered by a cross-media effect evaluation include, but are not limited to, energy consumption, use of chemicals, waste production, fate and/or effect of substances in the effluent discharged that are not separated but may affect the treatment method and health and safety aspects.

Table 1 List of potential measures for the removal of heavy metals, dissolved oil, dispersed oil and offshore chemicals from produced water

A. Preventive techniques • Down-hole oil-water separation (DHWS) • Down-hole gas-water separation (DHWS) • Mechanical water shut-off • Chemical water shut-off **B. Process integrated techniques** • Methanol recovery unit • Glycol regeneration (incl. Drizo) • Overhead vapour combustion (OVC) • Macro Porous Polymer Extraction (MPPE) (partial flow) • High pressure condensate-water separation • Steam stripping (glycol regeneration water) • Insulation of pipelines • Stainless steel lines and casks • Alternative methods of gas drying (IFPEXOL etc.) • Labyrinth type choke valve • Glycol overheads backflow to separator • Degassers **C. End of pipe techniques** **Conventional techniques** • Gas flotation (DGF/IGF) • Flotation cells • CPU compact flotation unit • Plate separator (CPI/PPI) • Hydrocyclone • Axiflow cyclones • Skimmer tank • Centrifuge • Disk stacked centrifuges • Produced water re-injection (PWRI) • Filter coalescer, incl. - sand filters - filters filled with oleophilic resins - etc. • Screen coalescers • Pall coalescers • In-line coalescing technology (incl. Mare's Tail and PECT-F) • Performance enhancing coalescer fiber • FU filter unit • Integral plate packs in three phase separators **Biological techniques** • Aerobic • Bioreactor (anaerobic) • Membrane bioreactor (MBR) • Enzyme reactor • Compost filter (glycol overhead) • Bacterial treatment	**Membrane techniques** • Micro-filtration • Ultra-filtration • Nano-filtration • Membrane separator • Reversed osmosis • Pertraction • Emulsion pertraction • Electro-dialyse • Membrane assisted affinity sorption (MAAS) **Absorption / adsorption techniques** • Absorption filter • Granular active carbon • Powder carbon • Ion exchange • Centrifugal absorption techniques • Zeolites • MPPE (end flow) • MPPS • Reusable oil adsorbent (RPA) **Stripping techniques** • Steam stripping (end flow) • Air stripping • Gas stripping **Evaporation** • Evaporation system • Freezing concentration **Oxidation techniques** • O_3 • H_2O_2 • Oxidation / neutralisation / de-watering (OND) • Vertech • $KMnO_4$ • Natural air • Electron beam • Plasma • Sonolysis • Photo catalytic oxidation • Low temperature hydro-thermal gasification (LTHG)

Table 1 Cont.

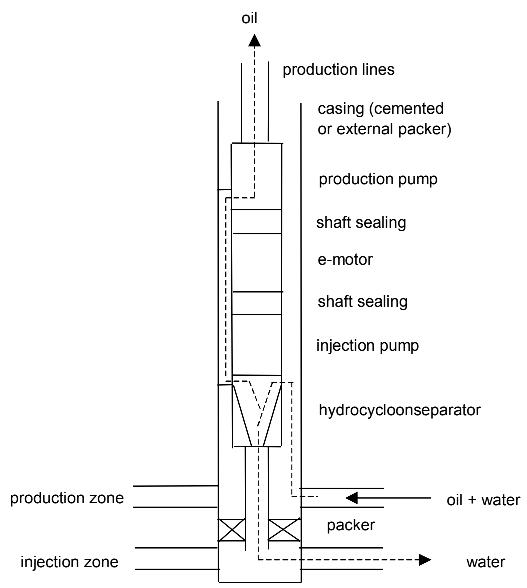
Other techniques	Combination of techniques
• Multimedia filtration/coalescers • Coagulation/flocculation • Electro-coagulation • Electrolytic treatment • Chalk precipitation • Sulphide precipitation • Grain reactor • High gradient magnetic separation • Pack of balls in PPI • Monitoring en control • Good operating practices • Optimal application of CHARM • Processes based on gas drying by adsorption • Glycol cleaning • Electrolysis	• Flocculation & hydrocyclone • Cyclone & electro-coalescer • Glycol regeneration and steam stripping

Table 2 Examples of techniques that are currently available or emerging for the treatment of produced water from offshore oil and gas installations as part of a BAT/BEP solution

			Gas production *		Oil production *	
	Table	*Page*	*Present*	*Emerging*	*Present*	*Emerging*
Preventive						
Downhole water separation - oil	Table A - 1	11			X	
Downhole water separation - gas	Table A - 2	13		X		
Mechanical water shut off	Table A - 3	15	X		X	
Chemical water shut off	Table A - 4	17	X		X	
Stainless steel tubing, flow lines, pipelines	Table A - 5	19	X		X	
Insulation of pipelines	Table A - 6	21	X			
Process integrated, including split stream treatment						
Overhead Vapour Combustion (OVC)	Table B - 1	23	X			
Fluid from condensor to production separator	Table B - 2	25	X			
Alternative methods of gas drying	Table B - 3	27	X			
MPPE (split stream)	Table B - 4	29	X			
Steam stripping, split stream	Table B - 5	31	X			
HP water condensate separator	Table B - 6	33	X			
Methanol recovery unit	Table B - 7	35	X			
Labyrinth type choke valve	Table B - 8	37		X		
End of pipe						
Skimmer tank	Table C - 1	41	X		X	
Produced water re-injection (PWRI)	Table C - 2	43	X		X	
DGF/IGF	Table C - 3	45	X		X	
PPI / CPI (gravitation separation)	Table C - 4	47	X		X	
Hydrocyclones	Table C - 5	49	X		X	
MPPE (end stream)	Table C - 6	51	X			X
Centrifuge	Table C - 7	53	X			
Steam stripping, end stream	Table C - 8	55	X			
Adsorption filter	Table C - 9	57	X			
Membrane filtration	Table C - 10	59		X		X
V-Tex	Table C - 11	61		X	X	
Filter coalescer	Table C - 12	63		X		X
CTour	Table C - 13	65		X		

PPI / CPI	=	Parallel Plate Interceptor / Corrugated Plate Interceptor (gravitation separation)
DGF / IGF	=	Dissolved Gas Flotation / Induced Gas Flotation
HP	=	High Pressure
MPPE	=	Macro Porous Polymer Extraction

* Although a distinction is made in this table between oil and gas producing installations, the limits of applicability of specific techniques may not be as rigid. These limits are, amongst other factors, dependent on the composition of the oil / condensate / gas and water produced.

<table>
<tr><th colspan="7">Table A - 1: Table down hole oil-water separation (DHS) - oil</th></tr>
<tr><td>Principle</td><td colspan="6">DHS for oil is a technique in which the production of an oil-water mix at the bottom of a production well is separated by a hydrocyclone. Separated water is injected into a suitable underground zone and the remaining oil-water mix is pumped to the surface. In this way, the amount of produced water can be reduced by more than 50%. This will result in a higher oil production, a relatively low water production and the use of less chemicals. The discharge and treatment of produced water is considerably reduced or the water injection installation could be considerably decreased.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Pump(s), hydrocyclone(s), e-motor, seals, instrumentation and changes in the well (deepening of well and /or additional perforations and packers)</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
■ Cadmium
■ Zinc
■ Lead
■ Mercury
■ Nickel</td><td rowspan="2">R [%]
50
50
50
50
50</td><td rowspan="2">Production chemicals
□ Methanol
□ Glycols
■ Corrosion inhibitors
■ Anti-scale solutions
■ Demulsifiers</td><td rowspan="2">R [%]

50
50
35</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]
50
50
50
50</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
50</td></tr>
<tr><td colspan="6">Remarks:
The 50% reduction is based on a 50% effectiveness of the hydrocyclone in the well. Less offshore chemicals need to be added, although the use of demulsifiers is usually not proportionately smaller.</td></tr>
<tr><td>Technical details</td><td colspan="4">Type of installation
Produced water volume (design)
Required area for injection vs. water treatment installation
Mass of equipment for injection vs. water treatment installation</td><td colspan="2">Oil
175 m^3/h
less
smaller</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The availability of a suitable water injection zone, which allows for fracturing, as well as an appropriate well configuration is a prerequisite for the application of this technique. Produced solid materials are separated largely into the water phase and may plug the injection zone. DHS is only suitable for oil > 20 °API and a water cut >50%. The composition of the injection water must be compatible with the injection zone. Production and injection zones must be sufficiently isolated. The diameter of the casings must be large enough to allow for a DHS system. DHS is seldom suitable in horizontal wells.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">Results presented are variable: only 60% of the test installations produce more oil than previous installations, and one third of the failures was the result of plugging of the injection zone. Some installations have been operational for more than 2 years, while others failed within a few days. The life span of a DHS installation is estimated to be half that of a standard pump installation.</td></tr>
</table>

Indication of costs

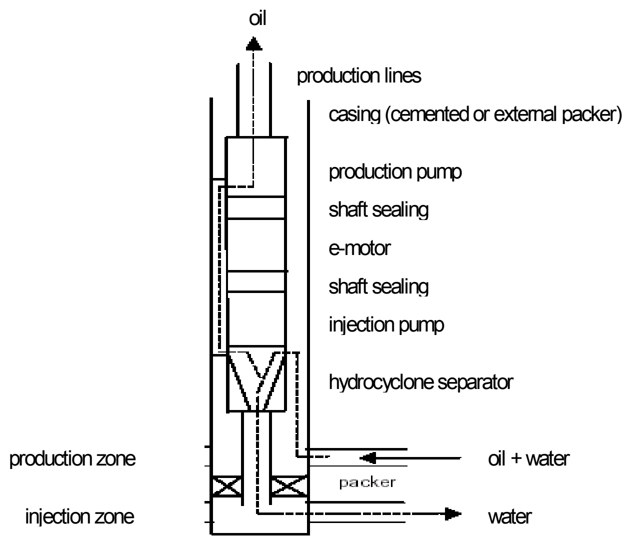
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	n.a.	n.a.	n.a.	n.a.
gas platform, large	n.a.	n.a.	n.a.	n.a.
oil platform	2 450 000	1 290 000	959 400	523 000

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil					1 460	796
dispersed oil	n.a.	n.a.	n.a.	n.a.	88	48
zinc equivalents					41 261	22 494

Remarks:
Costs were presented for one DHS installation of 50 m^3/h. In order to reduce a nominal water production of 150 m^3/h by 50%, a minimum of 3 DHS installations would be required. Depreciation in the OPEX for an existing offshore installation is based on deepening an existing well and installing a liner ad. € 2 MM. Costs for a workover of a DHS installation were estimated at € 550 000. Cuts on costs for reduced energy consumption on an existing offshore installation were not taken into account, neither was additional production of wells that are not producing on maximum capacity. For new offshore installations, large savings may be possible regarding the water treatment system.

Cross media effects	**Air**	Decreased energy use leads to decreased air emissions, especially when diesel fuel is used.
	Energy	Decreased energy use for water transport pumps. Possible increased or decreased energy use for the pumps in the well, depending on the required injection pressure.
	Added chemicals	Possibly scale inhibitor or acid to stimulate the injection zone.
	Waste	The decreased water through flow should result in a decrease in sludge in the water treatment installation. The sludge is often slightly radioactive (NORM).
Other impacts	**Safety**	Slight increase in view of increased number of workovers.
	Maintenance	Maintenance of the water treatment installation for existing installations will definitely decrease. Replacement of the DHS installation on average every 1,5 years.

	General	**Offshore**
Practical experience	The results to date are very variable. The technique is considered very promising but is still in the development stage.	DHWS is mostly used onshore, in situations where the water treatment capacity is limited.
Conclusion	☐ BAT	■ Emerging Candidate for BAT, very promising technique
Literature source	[1]	

<table>
<tr><th colspan="7">Table A - 2: Down hole oil-water separation (DHS) - gas</th></tr>
<tr><td>Principle</td><td colspan="6"></td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Pump(s), hydrocyclone(s), e-motor with variable number of revolutions, seals, instrumentation and changes in the well (deepening of well and /or additional perforations and packers)</td></tr>
<tr><td rowspan="2">Suitable for the removal of:

R = removal efficiency</td><td>Heavy metals
■ Cadmium
■ Zinc
■ Lead
■ Mercury
■ Nickel</td><td>R [%]
50-100
50-100
50-100
50-100
50-100</td><td>Production chemicals
■ Methanol
■ Glycols
■ Corrosion inhibitors
■ Anti-scale solutions
■ Demulsifiers</td><td>R [%]
<75%
<75%
100
50-100
15-35</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs
Dispersed oil
■ Oil</td><td>R [%]
50-100
50-100
50-100
50-100
R [%]
50-100</td></tr>
<tr><td colspan="6">Remarks:
The 50-100% removal efficiency is applicable to the amount of formation water, which is 25-50% of the total water production. E.g.: if 50% of the formation water production (1,4 m^3/h) stems from one well, DHWS will reduce the total water production from this well by 75% x 50% x 1,4 m^3 = 0,53 m^3/h. Reduction of chemicals is less than proportionate. Lower salt concentrations lead to more oil/water emulsions, in some cases leading to increased use of demulsifiers and higher dispersed/dissolved oil concentrations. Lower salt concentrations will lead to increased use of methanol/glycol (hydrate inhibitors). A large part of the condensation water will be produced (depending on the well pressure).</td></tr>
<tr><td>Technical details</td><td colspan="4">Type of installation
Produced water volume (design)
Required area for injection vs. water treatment installation
Mass of equipment for injection vs. water treatment installation</td><td>Gas 1
1 m^3/h
n.a.
n.a.</td><td>Gas 2
6 m^3/h
less
lower</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">DHS is only suitable for gas wells with little condensate production. Presence of a suitable layer for water (and condensate) injection and for fracturing and suitable (existing) well configurations is required. Composition of injection water must be compatible with the injection zone (swelling of clay etc.). Production and injection zones must be adequately isolated. Depressurising the well in order to pull the injection pump may cause damage to the production zone.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">From the few references it is evident that results vary. Problems may be expected when produced water contains sand or clay particles, which could plug the injection zone.</td></tr>
</table>

Indication of costs

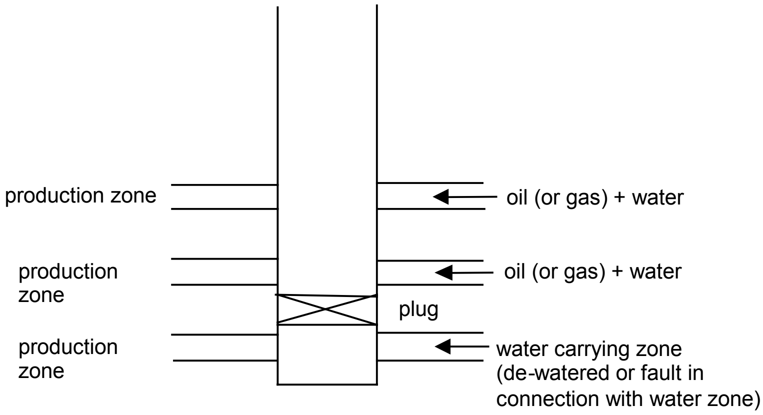
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	n.a.	n.a.	n.a.	n.a.
gas platform, large	2 550 000	1 390 000	890 600	444 200
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	n.c.	n.c.	1 320	659	n.a.	n.a.
dispersed oil			4 842	2 415		
zinc equivalents			64 438	32 635		

Remarks:
Costs have been included for a DHS installation of 0,7 m^3/h, although an installation for 2 m^3/h would cost little extra. In order to achieve a 75% reduction of formation water, each well would have to be fitted with a DHS installation. Depreciation in the OPEX for an existing offshore installation is based on deepening an existing well and installing a liner ad. € 2 MM. Costs for a workover of a DHWS installation were estimated at € 4 000 000. The reduction of condensate production was not taken into account.

Cross media effects	**Air**	Higher energy consumption will increase air emissions, especially when using diesel fuel.
	Energy	Energy consumption for the pumps in the well depends on the required injection pressure and the amount of water.
	Added chemicals	Possibly scale inhibitor or acid to stimulate the injection zone.
	Waste	The decreased water through flow should result in a decrease in sludge in the water treatment installation. The sludge is often slightly radioactive (NORM).
Other impacts	**Safety**	Slight increase in view of increased number of workovers.
	Maintenance	Maintenance of the water treatment installation for existing installations will definitely decrease. Replacement of the DHS installation every 2 years.

	General	**Offshore**
Practical experience	There are few references. The technique is in the phase of development.	It is expected that this technique will be tested onshore first. Currently, pumping of water to the surface is preferred.
Conclusion	☐ BAT	■ Emerging Candidate for BAT
Literature source	[1]	

Table A - 3: Mechanical water shut-off	
Principle	When water breakthrough occurs in oil or gas production, production zones with high water cuts can be sealed by installing mechanical barriers. This may, dependent on well configuration, be achieved by mechanical or inflatable plugs, cementing, placement of a patch (expansion pipe) or pack-off, possibly in combination with chemical treatment (see table on Chemical water shut off). If total sealing of the water production is not desired, a regulating mechanism or restriction plate may be placed in the well.
Process diagram	
Basic elements	Mechanical plugs, cement, pack-off etc. Preferably, the process of completion of a well takes into account the possibility of sealing of zones which may produce large amounts of water, e.g. by cementing casings.

Suitable for the removal of:	Heavy metals	R [%]	Production chemicals	R [%]	Oil	R [%]
	■ Cadmium	50-75	■ Methanol	<55	■ **Dissolved oil**	50-75
R = removal efficiency	■ Zinc	50-75	■ Glycols	<55	■ BTEX	50-75
	■ Lead	50-75	■ Corrosion inhibitors	50-75	■ Benzene	50-75
	■ Mercury	50-75	■ Anti-scale solutions	50-75	■ PAHs	50-75
	■ Nickel	50-75	■ Demulsifiers	15-35	**Dispersed oil**	**R [%]**
					■ Oil	50-75

Remarks:
The effectiveness of a sealing is dependent on successfully installing the plug and the way the well was completed, e.g. the sealing around the casing or liner. Reduction of chemicals is less than proportionate. Lower salt concentrations lead to more oil/water emulsions, in some cases leading to increased use of demulsifiers and higher dispersed/dissolved oil concentrations. Lower salt concentrations will lead to increased use of methanol/glycol (hydrate inhibitors). Formation water will inevitably be produced in view of natural water saturation (conate water).

Technical details	Type of installation	Gas 1	Gas 2	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	175 m^3/h
	Area required for water treatment	less	less	less
	Mass of equipment for water treatment installation	lower	lower	lower

Critical operational parameters	Study is required to identify the source of water production and reduce the risk of plugging the production. Mechanical water shut off is mainly applicable for multi-layer reservoirs. In horizontal wells, this technique is often more difficult and more expensive. Possible leakage of existing sealings around casing (cement or packer) may reduce the effect of the sealing. Production lines must be pulled out unless inflatable plugs can be placed via these lines. Inflatable plugs and some patches are resistant to limited pressures. Sometimes water sealing leads to production loss.
Operational reliability	The reliability of mechanical and cement plugs is modest, absolute certainty about closing in water is rare. Dependent on the well configuration, the rate of success is 40-70% (closer to 40% for gas installations). Inflatable plugs and pack-offs are less reliable (failure by high pressure or damage). When a patch doesn't seal well, e.g. because of salt deposition in tubings, erosion and corrosion may occur.

Indication of costs

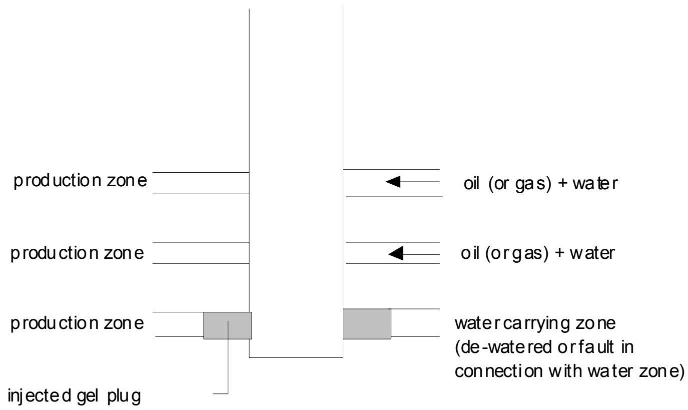
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	200 000-800 000	n.a.	50 800-209 200	n.a.
gas platform, large	200 000-800 000	n.a.	48 800-207 200	n.a.
oil platform	170 000-300 000	n.a.	20 900-45 200	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	1 374-5 660	n.a.	116-491	n.a.	106-229	n.a.
dispersed oil	2 062-8 490		424-1 802		6,4-13,8	
zinc equivalents	39 564-162 928		5 642-23 954		2 986-6 457	

Remarks:

- The technique is only applied on existing offshore installations, although provisions can be made on new installations.
- Including costs of removal and replacement of production lines with drilling rig (gas). On oil installations, the installation is combined with the replacement of pumps (ESP), therefore only additional costs should be calculated. Lower costs are for use of a platform rig. Possible costs for loggings should be calculated.
- The KEw is difficult to assess, since the costs vary and production may reduce. KEw may be calculated but should be raised with risk.
- The costs model situation is presented for one well and a reduction of 62,5% of formation water. In case that the amount of formation is 75% or 50% of the total water production, the reductions are 62,5% x 75% x 0,2 m^3/h and 62,5% x 50% x 1,4 m^3/h respectively. Oil platforms also require extra costs for reducing 1/5 of the water production by 50% (for one well 50% of 30 m^3/h). A total of 5 wells is required for similar reservoir and production.
- Costs for horizontal wells are usually higher.
- Possible slight savings in energy costs were not calculated, neither was possible additional oil or gas production.

Cross media effects	**Air**	Less energy consumption will reduce air emissions, especially when diesel fuel is used.
	Energy	Reduced energy consumption for water pumps etc.
	Added chemicals	Reduced use of chemicals for water treatment e.g. scale inhibitors, corrosion inhibitors, demulsifier.
	Waste	Less (often slight radioactive, NORM) sludge deposition in view of reduced water production.
Other impacts	**Safety**	None.
	Maintenance	Maintenance of water treatment facilities will definitely reduce. In principle no maintenance on mechanical seal needed.
Practical experience	**General**	**Offshore**
	Mechanical water shut off is applied frequently.	These techniques can be applied offshore.
Conclusion	■ BAT	□ Emerging Candidate for BAT
Literature source	[1]	

<table>
<tr><th colspan="2">Table A - 4: Chemical water shut off</th></tr>
<tr><td>Principle</td><td>When water breakthrough occurs with oil or gas production, production zones with high water cuts can be sealed by the placement of special polymers. By adding cross-linkers, gel is formed which blocks water. Chemical sealing is often applied in higher production zones. The advantage in comparison with mechanical shut off is that the full diameter of the well remains available for any well repairs and the chance for flow behind the tubing is less, since the gel perforates the formation deeply. The disadvantage is that the gel normally cannot be removed anymore when production proves less. Sometimes polymers are injected to reduce the relative permeability for water, whereas the permeability for gas remains the same.</td></tr>
<tr><td>Process diagram</td><td>
</td></tr>
<tr><td>Basic elements</td><td>Polymer, cross-linker, catalyst, filler. There are many types of anorganic and bio-polymers. In gas wells, the gel is often placed by a coiled tubing. In oil wells, a workover, or production lines may be appropriate. Preferably, the process of completion of a well takes into account the possibility of sealing zones which may produce large amounts of water, e.g. by cementing tubings.</td></tr>
<tr><td>Suitable for the removal of:

R = removal efficiency</td><td>
<table>
<tr><th>Heavy metals</th><th>R [%]</th><th>Production chemicals</th><th>R [%]</th><th>Oil</th><th>R [%]</th></tr>
<tr><td>■ Cadmium</td><td>50-75</td><td>■ Methanol</td><td><55</td><td>■ Dissolved oil</td><td>50</td></tr>
<tr><td>■ Zinc</td><td>50-75</td><td>■ Glycols</td><td><55</td><td>■ BTEX</td><td>50</td></tr>
<tr><td>■ Lead</td><td>50-75</td><td>■ Corrosion inhibitors</td><td>50-75</td><td>■ Benzene</td><td>50</td></tr>
<tr><td>■ Mercury</td><td>50-75</td><td>■ Anti-scale solutions</td><td>50-75</td><td>■ PAHs</td><td>50</td></tr>
<tr><td>■ Nickel</td><td>50-75</td><td>■ Demulsifiers</td><td>50-75</td><td>Dispersed oil</td><td>R [%]</td></tr>
<tr><td></td><td></td><td></td><td></td><td>■ Oil</td><td>50</td></tr>
</table>
Remarks:
The effectiveness of sealing is dependent on successful placement of the gel and of the physical interaction between oil or gas and water. Reduction of chemicals is less than proportionate. Lower salt concentrations lead to more oil/water emulsions, in some cases leading to increased use of demulsifiers and higher dispersed/dissolved oil concentrations. Lower salt concentrations will lead to increased use of methanol/glycol (hydrate inhibitors). Formation water will inevitably be produced in view of natural water saturation (conate water).</td></tr>
<tr><td>Technical details</td><td>
<table>
<tr><td>Type of installation</td><td>Gas 1</td><td>Gas 2</td><td>Oil 1</td></tr>
<tr><td>Produced water volume (design)</td><td>1 m^3/h</td><td>6 m^3/h</td><td>175 m^3/h</td></tr>
<tr><td>Area required for water treatment installation</td><td>less</td><td>less</td><td>less</td></tr>
<tr><td>Mass of equipment for water treatment installation</td><td>lower</td><td>lower</td><td>lower</td></tr>
</table></td></tr>
<tr><td>Critical operational parameters</td><td>Study is required to identify the source of water production and reduce the risk of plugging the production. The maximum allowable temperature is 150 °C (dependent on type of gel). Chemical water shut off is mainly applicable for multi-layer reservoirs (water should no be able to flow around the blockade) but it can also be applied in horizontal wells. For the sealing of fractures, large amounts of activated gel are needed, followed by gel and filler.</td></tr>
<tr><td>Operational reliability</td><td>The reliability of chemical plugging is modest, absolute certainty about closing-in water is rare. Dependent on the communication between zones, the rate of success is 30-70%. Advantage of polymers that reduce relative permeability is that they need not to be injected in a specific zone, which increases the reliability of sealing.</td></tr>
</table>

Indication of costs

Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	170 000-480 000	n.a.	42 900-124 700	n.a.
gas platform, large	170 000-480 000	n.a.	40 900-122 700	n.a.
oil platform	150 000-520 000	n.a.	15 600-113 300	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	1 161-3 374	n.a.	97-291	n.a.	79-575	n.a.
dispersed oil	1 741-5 061		356-1 067		4,7-34	
zinc equivalents	33 411-97 118		4 728-14 185		2 229-16 186	

Remarks:

- The technique is only applied on existing offshore installations, although provisions can be made on new installations, that may later on reduce CAPEX (costs for these provisions should not be added when calculating KEw, costs are based on 1 000-1 500 €/m^3 gel).
- CAPEX includes coiled tubing (gas). On oil installations, polymer injection is combined with the replacement of pumps (ESP); therefore only additional costs should be calculated. A platform rig requires lower costs than a jack-up rig and sealing of fractures (high volume needed). Possible costs for loggings should be calculated.
- The KEw is difficult to assess, since the costs vary and production may reduce. KEw may be calculated but should be raised with risk.
- Costs for model situation platforms are for 1 well, needed to reduce 62,5% formation water. If formation water forms 75% or 50%, the reduction is 62,5% x 75% x 0,2 m^3/h and 62,5% x 50% x 1,4 m^3/h respectively, for an oil installation also costs for 1 well to reduce 1/5 of the water production with 50% (50% of 30 m^3/h) (a total of 5 wells needed if reservoir and production are similar).
- Costs for sealing of fractures are usually high in view of large quantity of gel needed.
- Possible slight savings in energy costs were not calculated, neither was possible additional oil or gas production.

Cross media effects	**Air**	Less energy consumption will reduce air emissions, especially when diesel fuel is used.
	Energy	Reduced energy consumption for water pumps etc.
	Added chemicals	Reduced use of chemicals for water treatment e.g. scale inhibitors, corrosion inhibitors, demulsifier.
	Waste	Less (often slight radioactive, NORM) sludge deposition in view of reduced water production.
Other impacts	**Safety**	None.
	Maintenance	Maintenance of water treatment facilities will definitely reduce. In principle no maintenance on chemical seal needed.

Practical experience	**General**	**Offshore**
	Chemical water shut off is applied frequently.	These techniques can be applied offshore.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

<table>
<tr><th colspan="7">Table A - 5: Stainless steel tubing, flow lines, pipelines</th></tr>
<tr><td>Principle</td><td colspan="6">In the presence of free water during the transport of oil and gas where H_2S and/of CO_2 are present, corrosion could occur where carbon steel is used. Depending on the degree of corrosion (depending on the temperature, the CO_2 level, the pressure of the medium and the planned life span) a combination can be used of control measures such as the development of corrosion margins, the use of corrosion inhibitors or the use of corrosion resistant material.
The use of corrosion inhibitors in combination with a high pressure step can lead to formation of stable oil-water emulsions with a small particle size that are difficult to separate. The use of corrosion resistant material, possibly in combination with high pressure separation, requires little or no use of corrosion inhibitors, which leads to a decrease of aromatic hydrocarbons in overboard water.
For low pressure lines, synthetic materials (GRE/GRP) may be used, but for high pressure lines and pipelines duplex steel (>18% Cr / 5% Ni) or (Inconel) coating is used. Stainless steel vessels may be used or vessels may be coated with a protective coating.</td></tr>
<tr><td>Process diagram</td><td colspan="6">Not applicable</td></tr>
<tr><td>Basic elements</td><td colspan="6"></td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td>Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td>R [%]</td><td>Production chemicals
☐ Methanol
☐ Glycols
■ Corrosion inhibitors
☐ Anti-scale solutions
■ Demulsifiers</td><td>R [%]

100

50-100</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs
Dispersed oil
■ Oil</td><td>R [%]
*
*
*
*
R [%]
*</td></tr>
<tr><td colspan="6">Remarks:
*: The removal efficiency for dissolved and dispersed oil depends, amongst others, on produced water treatment systems installed and whether high pressure oil water separation is applied. If demulsifier is in injected, the specific removal efficiency may reduce considerably.</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td>Technical details</td><td colspan="3">Platform
Produced water volume (design)
Required area (LxWxH)
Mass (filled)</td><td>Gas 1
1 m^3/h
n.a.
n.a.</td><td>Gas 2
6 m^3/h
n.a.
n.a.</td><td>Oil 1
175 m^3/h
n.a.
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">Operations and control of the oil content in produced water are enhanced when less corrosion inhibitors are injected. Corrosion increases exponentially with raising temperature. The need for use of corrosion inhibitors may be reduced considerably when the water treatment facilities are operated in a way so as to prevent oxygen entering (possibly separated systems).</td></tr>
<tr><td>Operational reliability</td><td colspan="6">The resistance of stainless steel against corrosion and erosion is better and therefore the life span is longer.</td></tr>
</table>

<table>
<tr><td rowspan="1">Indication of costs</td><td colspan="3">The use of materials that are resistant against corrosion leads to savings in the use of corrosion inhibitors and maintenance. For a gas pipeline with a capacity of 1,5 MM Nm^3/d, these savings total € 34 000 per year. With a life span of 15 years, this totals € 510 000. If no corrosion inhibitor injection system is needed, a further saving of investments of € 40 000 is achieved. Additional investments for stainless steel in comparison with carbon steel pipelines amounts approximately to € 375 per meter (for 10” and 12” € 500/m and € 750 respectively). The break even point for such a pipeline would be 1,5 km. Since this is much shorter than most pipelines, this investment would not be justifiable. When production is higher and when other business economic factors are taken into account, or when the gas is very corrosive, the use of stainless steel may be preferred.
Since duplex steel is more resistant against erosion, smaller diameters can often be applied, thus reducing costs. In some cases the use of smaller diameter pipelines renders cementing pipelines unnecessary.</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="2">None.</td></tr>
<tr><td>Energy</td><td colspan="2">None.</td></tr>
<tr><td>Added chemicals</td><td colspan="2">Reduction of corrosion inhibitors, for gas 10 l/MM Nm^3 and water approximately 100 mg/l.</td></tr>
<tr><td>Waste</td><td colspan="2">None.</td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="2">Safer, since less drums with corrosion inhibitors need to be handled (satellite platforms) and because of reduced leakage and corrosion problems.</td></tr>
<tr><td>Maintenance</td><td colspan="2"></td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="2">General</td><td>Offshore</td></tr>
<tr><td colspan="2"></td><td>Corrosion resistant materials are frequently applied for (pipe)lines and vessels.</td></tr>
<tr><td>Conclusion</td><td colspan="2">■ BAT</td><td>☐ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="3">[1]</td></tr>
</table>

Table A - 6: Insulation of pipe lines

Principle	When gas is transported under high pressure from a satellite to a treatment facility on a central installation, there is a danger of hydrate formation as the mixture of gas and water cools down. This may lead to blockages in the pipeline. There are three different methods available to prevent this problem: 1. Injection of methanol or glycol (MEG/TEG), or other chemicals that may, or may not be retrieved and regenerated on the central platform; 2. Maintaining the temperature as much as possible by burying and possibly adding insulation to the pipeline; 3. Lowering the pipeline pressure, in order to allow for operation outside the hydrate-regime. This may be possible when sufficient compression facilities are installed on the central platform, but usually this is not desired since this reduces the pipeline capacity considerably and energy is wasted. The only alternative for continuous injection of chemicals is therefore insulation of the pipeline. This is only effective when production is continuous and a minimum production is maintained. During start up and when producing below the required minimum, methanol will need to be injected in order to prevent the formation of hydrates.
Process diagram	Not applicable
Basic elements	Insulated and/or buried pipelines.

Suitable for the removal of:

R = removal efficiency

Heavy metals	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
☐ Cadmium		■ Methanol	>90	☐ **Dissolved oil**	*
☐ Zinc		■ Glycols	100	☐ BTEX	*
☐ Lead		☐ Corrosion inhibitors		☐ Benzene	*
☐ Mercury		☐ Anti-scale solutions		☐ PAHs	*
☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
				☐ Oil	

Remarks:

For start up operations and production below the required minimum, injection of small amounts of methanol is required. This will be discharged with produced water.

*: When glycol is used, the insulation renders re-feeding of water with a high content of aromatic hydrocarbons from the condensor of the regenerator unnecessary.

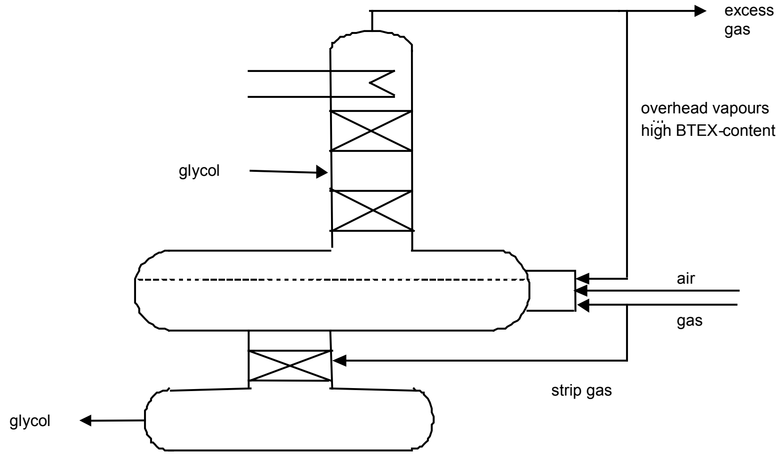
Technical details

Platform	Gas 1	Gas 2	Oil
Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
Pipeline length	3-10 km	3-15 km	
Pipeline diameter	8”-10”	14”- 16”	

Critical operational parameters	The formation of hydrates may occur at a pressure/temperature relation of approximately 25 bar/4 °C or 100 bar/20 °C. Salt in produced water will reduce the formation of hydrates. A minimum production needs to be maintained in order to keep the pipeline at a certain temperature. With the ageing of the field and reduced reservoir pressure, methanol injection will be reduced.
Operational reliability	The use of methanol will still be needed during start up operations. Insulation is less effective when the throughput is low.

<table>
<tr><td>Indication of costs</td><td colspan="3">The costs of insulation are dependent on the required level of insulation. The use of advanced systems (e.g. pipe-in-pipe) may double the costs for a pipeline. For gas-condensate lines, additional costs are approximately € 230 000/km.

A considerable saving is achieved by the elimination of a methanol recovery unit or glycol regenerator. Savings due to reduced methanol use may vary from 5% to 30% of the amount of produced water. With decreasing pressure, this percentage is lower until no injection is needed at a pipeline pressure of 25 bar.</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="2">No emissions due to regeneration of methanol or glycol.</td></tr>
<tr><td>Energy</td><td colspan="2">No energy consumption for regeneration of methanol or glycol.</td></tr>
<tr><td>Added chemicals</td><td colspan="2">Insulation prevents the continuous injection and regeneration of methanol/glycol. No regeneration loss from methanol/glycol, no loss of methanol to gas and condensate phase or use of other chemicals.</td></tr>
<tr><td>Waste</td><td colspan="2">None.</td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="2">No risks due to transfer of large amounts of methanol.</td></tr>
<tr><td>Maintenance</td><td colspan="2">No maintenance on methanol or glycol regeneration systems.</td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="2">General</td><td>Offshore</td></tr>
<tr><td colspan="2">Insulation and burying the pipeline is used frequently in the oil and gas industry.</td><td>Insulation is also applied offshore.</td></tr>
<tr><td>Conclusion</td><td colspan="2">■ BAT</td><td>☐ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="3">[1]</td></tr>
</table>

<table>
<tr><th colspan="7">Table B - 1: Overhead vapour combustion (OVC)</th></tr>
<tr><td>Principle</td><td colspan="6">Application of OVC eliminates the most important source of BTEX in produced water, i.e. condensate from the glycol regeneration unit. OVC does not condense the vapours from regeneration but these vapours are incinerated under controlled conditions in the burner of the glycol regenerator.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Special burner (suitable for wet gas) with ‘fire way’ and higher stack.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
□ Cadmium
□ Zinc
□ Lead
□ Mercury
□ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
■ Methanol
□ Glycols
■ Corrosion inhibitors
□ Anti-scale solutions
□ Demulsifiers</td><td rowspan="2">R [%]
> 99% *

**</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]
>99
>99
>99
>99</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
>99**</td></tr>
<tr><td colspan="6">Remarks:
Almost all hydrocarbons, including strip gas, is burned.
*: When used.
**: The hydrophobic part is removed.</td></tr>
<tr><td>Technical details</td><td colspan="2">Platform
Produced water volume (design)
Partial flow (design)
Required area (extra) (LxWxH)
Mass (extra)</td><td>Gas 1 (small)
1 m^3/h
0,05 m^3/h
negligible
negligible</td><td colspan="2">Gas 2 (large)
6 m^3/h
0,1 m^3/h
negligible
negligible</td><td>Oil 1
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The design should take due account of possible methanol injection. Installation of a new ‘fire way’ / burner, a higher stack and temperature regulation with air are the most important features when OVC is installed on an existing platform. A shut down period of 1-2 weeks is required. This renders high costs unless the installation is shut down for other reasons as well.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">As reliable as regular regeneration systems. The functioning of OVC is not affected very much by gas quality fluctuations, but may be affected if gas contains glycol due to malfunctioning of regeneration.</td></tr>
</table>

Indication of costs

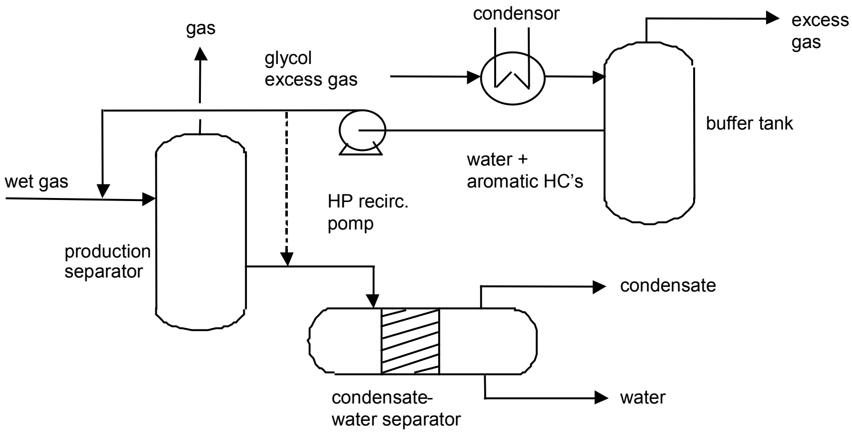
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	308 000	20 000	87 300	3 300
gas platform, large	381 000	0	108 600	0
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
benzene	532	20	94	0	n.a.	n.a.
aliphatic hydrocarbons						
zinc equivalents						

Remarks:
For smaller new installations (< 3 MM m^3/day) the CAPEX is approximately equal. For larger installations, the costs are lower since less equipment is needed (no condensor, gas scrubber, pump, instrumentation). Retrofitting on an existing installation amounts approximately to € 200 000 (materials).

Cross media effects	**Air**	Substantive reduction of air emissions. Other gases may also be used when OVC is installed (flash gas etc.) instead of them being vented. When a relative large amount of strip gas is needed, use of other gases is limited. NO_x emissions are less than 150 mg/m^3.
	Energy	Lower energy consumption in view of use of other gases.
	Added chemicals	None.
	Waste	None.
Other impacts	**Safety**	None.
	Health	No air emission of hydrocarbons.

Practical experience	**General**	**Offshore**
	More than 15 years of experience with OVC onshore industrial wastewater treatment.	OVC is applied offshore in new installations since 2000.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

<table>
<tr><th colspan="7">Table B - 2: Fluid from condensor to production separator</th></tr>
<tr><td>Principle</td><td colspan="6">Condensation of overhead vapours from the glycol regenerator produces a watery stream with a high concentration of dissolved oil. This relatively small stream is brought into contact, under high pressure, with a large amount of production water, gas and condensate in the production separator. The condensate and gas will extract a large part of aromatic hydrocarbons (dissolved oil), thus reducing discharge of aromatic hydrocarbons (dissolved oil). The glycol regeneration water is most effectively injected before the slug catcher or gas cooler, but may also be pumped to the water-condensate separator.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Line elements, buffer tank, recycle pump</td></tr>
<tr><td rowspan="2">Suitable for the removal of:

R = removal efficiency</td><td>Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td>R [%]</td><td>Production chemicals
■ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td>R [%]
*</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs

Dispersed oil
■ Oil</td><td>R [%]
>50
>50
>50
>50

R [%]
*</td></tr>
<tr><td colspan="6">Remarks:
The removal efficiency is related to the partial flow and dependent on the composition of gas and condensate and the quality of treatment systems.

*: Partially removed if present.</td></tr>
<tr><td>Technical details</td><td colspan="2">Platform
Produced water volume (design)
Partial flow (design)
Required area (LxWxH)
Mass (filled)</td><td>Gas 1 (small)
1 m³/h
0,05 m³/h
0,8 x 0,5 x 1 m
0,3 tonnes</td><td colspan="2">Gas 2 (large)
6 m³/h
0,1 m³/h
1 x 0,6 x 1,5 m
0,5 tonnes</td><td>Oil 1
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The advantages of this technique depend on the composition of gas and condensate, the separator pressure and temperature and may best be evaluated by using a process simulation.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">High.</td></tr>
</table>

Indication of costs

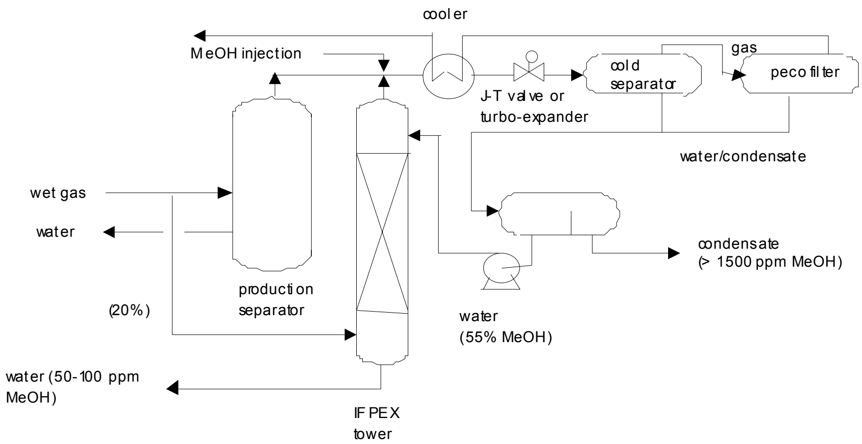
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	100 000	74 000	30 900	16 500
gas platform, large	115 000	85 000	35 900	19 400
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	376	201	62	34	n.a.	n.a.
dispersed oil	-	-	-	-		
zinc equivalents	-	-	-	-		

Cross media effects	**Air**	Little influence.
	Energy	For HP re-circulation pump.
	Added chemicals	None.
	Waste	None.
Other impacts	**Safety**	None.
	Maintenance	Only pump maintenance.

Practical experience	**General**	**Offshore**
		Is already applied offshore

Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table B - 3: Alternative methods of gas drying	
Principle	Usually, gas washers are used for gas drying. The gas is washed in counter-flow with glycol (TEG or DEG). The solubility of aromatic hydrocarbons in glycol is high, causing high concentrations of aromatic hydrocarbons in water in the process regeneration of glycol. Alternative 'washing fluids' which render aromatic hydrocarbons less soluble, reduce the amount of aromatic hydrocarbons being removed. Alternative 'washing fluids' are MEG or methanol via the IFPEX process. These alternative 'washing fluids' will also remove less water, rendering this technique suitable especially in the case of the less stringent requirements with regard to dew point.
Process diagram	
Basic elements	IFPEX towers (strip towers), J-T valve (or turbo expander), cold separator, filter, water-condensate separator, pump

Suitable for the removal of:

R = removal efficiency

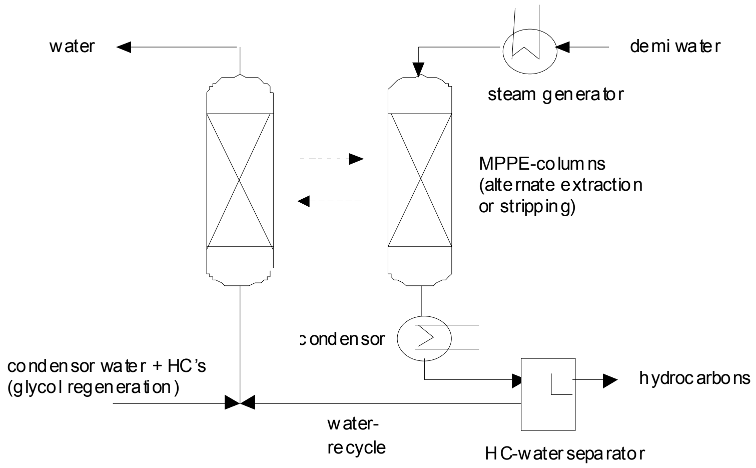
Heavy metals	R [%]	Production chemicals	R [%]	Oil	R [%]
☐ Cadmium		☐ Methanol		■ **Dissolved oil**	35-85
☐ Zinc		■ Glycols	100	■ BTEX	35-85
☐ Lead		☐ Corrosion inhibitors		■ Benzene	35-85
☐ Mercury		☐ Anti-scale solutions		■ PAHs	?
☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
				☐ Oil	

Remarks:
Removal efficiencies of the IFPEX process, using methanol as 'washing fluid'.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
	Partial flow (design)	0,05 m^3/h	0,1 m^3/h	
	Required area (LxWxH)			
	Mass (filled)			

Critical operational parameters	Only applicable when gas drying is not very critical. Relatively high use of methanol in view of absorption in gas and condensate, part of the methanol is lost in the water phase. Sufficient gas pressure is required in order to allow cooling with J-T valve (or more cooling capacity is needed). The cooling process preferably takes place below –20 °C, in order to limit methanol losses. Energy may be needed for recompression.
Operational reliability	Relatively easy operation. The IFPEX tower may also be installed on satellite platforms. No heat needed for regeneration. No foam forming or breaking up due to (over-) heating.

Indication of costs	In view of the fact that replacement of existing systems is concerned, no detailed cost analysis was performed. Rather a comparison of investment and operational costs with existing systems took place.	
	Table 1: Comparison of investments common systems vs. IFPEX Saving investments IFPEX compared to common systems TEG-system 25-30% MEG-system 10% Table 2: Comparison of operational costs common systems vs. IFPEX Saving investments IFPEX compared to common systems TEG-system 25-30% Glycol injection system 20%	
	Remarks: The major advantage of an IFPEX-1 system over more commonly applied systems is that no glycol regenerator is needed. Thus CAPEX and energy consumption are much lower. Moreover, process control is better. An IFPEX-system uses more methanol compared with traditional TEG gas drying systems. There are almost no air emissions. An IFPEX unit, however, does use large amounts of methanol. The IFPEX-1 system can easily be combined with the IFPEX-2 process for the removal of acidic gases (CO_2 and H_2S). Other alternative gas drying systems are: - Twister supersonic separator (see table C-13); and - DRIZO process; regeneration of DEG at lower temperature (160 °C) using solvent.	
Cross media effects	**Air**	No emissions of BTEX and VOS (incl. strip gas)
	Energy	IFPEX requires 80-90% less energy than a glycol system, provided that pressure is sufficient to allow cooling.
	Added chemicals	Methanol consumption approximately 275 l/day (small gas platform) and 1 900 l/day (large gas platform).
	Waste	Methanol (50-100 mg/l) in (small amount of) water from the IFPEX tower. No glycol consumption.
Other impacts	**Safety**	No glycol chain in area with potential danger of explosion.
	Maintenance	Far less maintenance.
Practical experience	**General**	**Offshore**
	Limited experience with alternative gas drying systems. Worldwide approximately 10 systems.	No difference with onshore application, except that J-T valve or expander is not economically feasible, since gas needs high pressure for transportation in the pipeline.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table B - 4: Macro porous polymer extraction (MPPE) (partial flow)	
Principle	On gas platforms, hydrocarbons can be removed from condensed water from the glycol regeneration process using Macro Porous Polymer Extraction (MPPE). Water from the glycol regeneration is directed through a column packed with a bed of MPPE material. An extraction fluid, immobilized in the MPP matrix, extracts hydrocarbons from the water phase. Treated water can be discharged immediately. Prior to reaching the (maximum) required effluent concentration, the feeds are lead through a second column; the first column is regenerated with low-pressure steam. Once the second column is saturated, the feeds are switched back to the first column. After a second cycle, the feeds are redirected to the first column again. A characteristic cycle lasts 1 to 2 hours. Steam and hydrocarbon vapours are condensed, and may easily be separated because of the high concentration of hydrocarbons. Hydrocarbons are lead to the condensate treatment system, the small amount of water is redirected into the installation and treated.
Process diagram	
Basic elements	2 columns filled with MPPE material, condenser, settling tank , steam generator (electric).

Suitable for the removal of: R = removal efficiency	**Heavy metals**	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
	☐ Cadmium		■ Methanol	>99 *	■ **Dissolved oil**	>99
	☐ Zinc		☐ Glycols		■ BTEX	>99
	☐ Lead		■ Corrosion inhibitors	**	■ Benzene	>99
	■ Mercury	?	☐ Anti-scale solutions		■ PAHs	>99
	☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
					■ Oil	>99 **

Remarks:

The removal efficiency of benzene and other dissolved hydrocarbons, including TEX, is very high: reductions of 2 000-3 000 mg/l to < 1 mg/l are possible. The occurrence of the removal of mercury during a test operation could not sufficiently be established.

*: if present

**: the hydrophobic part is removed.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
	Partial flow (design)	0,05 m^3/h	0,1 m^3/h	
	Required area (LxWxH), including steam generator	1 x 1,5 x 1,7 m	1 x 1,7 x 2 m	
	Mass (filled)	1,5 tonnes	2 tonnes	

Critical operational parameters	The MPPE material should be replaced in order to avoid loss of effectiveness. The feed water for the steam generator should be demineralised.
Operational reliability	The process is not affected very much by fluctuations in flow or BTEX-concentrations and can be fully automated (remote control).

Indication of costs

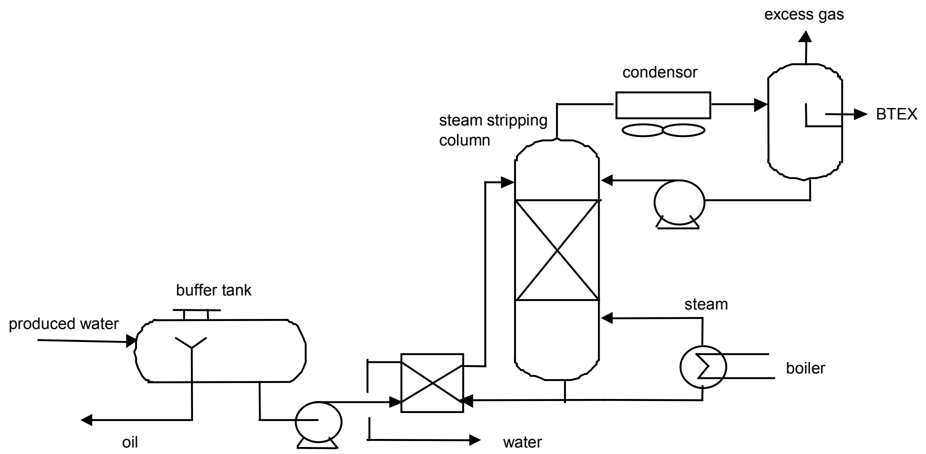
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	324 000	276 000	99 800	59 200
gas platform, large	368 000	313 000	117 300	71 200
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
Benzene	608	361	102	62	n.a.	n.a.
BTEX	486	289	82	50		

Remarks:
Including costs for replacement of MPPE extraction fluid.

Cross media effects	**Air**	Required energy will lead to increased air emissions.
	Energy	Electricity for steam generation (6-2,5 kg LP steam per m^3 water) and for pumps (total for 0,008 / 0,005 m^3/h resp. 4,4 / 13,2 MWh/year).
	Added chemicals	Extraction fluid is consumed very slowly, and is transported with the BTEX via the separator. Possibly chemicals for demineralisation of feed water for LP steam production.
	Waste	The MPPE bed should be replaced approximately every 2 years.
Other impacts	**Safety**	None.
	Maintenance	Relatively little.

	General	**Offshore**
Practical experience	Operational experience with MPPE-process in industrial waste water treatment. Successful treatment (partial flow and end flow) of produced water at TFE in Harlingen, the Netherlands.	Successful tests on partial flows.
Conclusion	■ BAT	□ Emerging Candidate for BAT
Literature source	[1] [6]	

<table>
<tr><th colspan="9">Table B - 5: Steam stripping (partial flow)</th></tr>
<tr><td>Principle</td><td colspan="8">Hydrocarbons can be removed from condensed water from glycol regeneration on gas platforms by means of steam stripping. The water is fed into a packed column and brought into intense contact with steam (known as stripping). This technique is suitable for the removal of dissolved oil (BTEX), but will also remove aliphatic hydrocarbons. Steam and hydrocarbon vapours are condensed and separated easily because of the high hydrocarbon content. Hydrocarbons that have been separated by steam can be directed to the condensate treatment system; water can be discharged.</td></tr>
<tr><td>Process diagram</td><td colspan="8">
</td></tr>
<tr><td>Basic elements</td><td colspan="8">Buffer tank, feeding pump, heat exchanger, stripping column, condensor, BTEX-accumulator, re-circulation pump, condensate pump, (electric) re-boiler.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2" colspan="2">Production chemicals
■ Methanol
☐ Glycols
■ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]
10-90*

**</td><td colspan="2">Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]
>99
>99
>99
>99</td></tr>
<tr><td colspan="2">Dispersed oil
■ Oil</td><td>R [%]
>97*</td></tr>
<tr><td colspan="8">Remarks:
The removal efficiency for BTEX is very high: reductions from 500-4 000 mg/l to < 1 mg/l, aliphatic hydrocarbons from 40 mg/l to < 1,5 mg/l.
*: When present.
**: The hydrophobic part is partly removed.</td></tr>
<tr><td>Technical details</td><td colspan="3">Platform
Produced water volume (design)
Partial flow (design)
Required area (LxWxH) (incl. steam generator)
Mass (filled)</td><td colspan="2">Gas 1 (small)
1 m^3/h
0,05 m^3/h
3 x 2 x 3 m

8 tonnes</td><td colspan="2">Gas 2 (large)
6 m^3/h
0,1 m^3/h
4 x 3 x 4 m

15 tonnes</td><td>Oil 1
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="8">In order to guarantee a constant flow, a buffer tank needs to be installed. This buffer tank also allows for skimming oil, avoiding disturbance of the process in the column. When the flow is very low, it may be necessary to add water in order to maintain the temperature at the top of the column. The steam line must be large enough in order to allow for equal levels in boiler and column (and above the bundle of the boiler).</td></tr>
<tr><td>Operational reliability</td><td colspan="8">The technique is reliable and is considered a proven technique for the treatment of glycol regeneration water.</td></tr>
</table>

Indication of costs

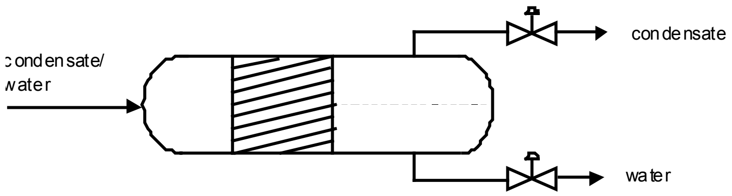
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	170 000	135 000	57 900	35 100
gas platform, large	265 000	210 000	90 700	55 000
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
benzene	354	214	79	48	n.a.	n.a.
BTEX	283	171	63	38		

Remarks:
Energy consumption is relatively high, despite the fact that part of the heat is recovered. Energy consumption can be reduced considerably when heat of the exhaust gases from turbines is used.

Cross media effects	**Air**	Required energy will increase air emissions. After the condensor little gases remain.
	Energy	Approximately 40 kWh/m^3 regeneration water (mainly for boiler).
	Added chemicals	None.
	Waste	None.
Other impacts	**Safety**	No significant influence.
	Maintenance	Relatively little.

Practical experience	**General**	**Offshore**
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

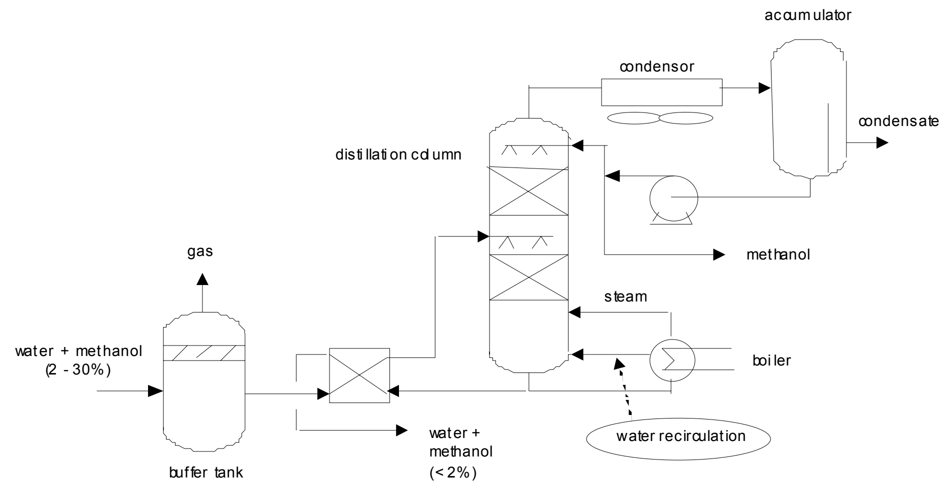
Table B - 6: High pressure water condensate separator	
Principle	On gas platforms the dispersed and dissolved oil content in produced water can be reduced by a high pressure (HP) water condensate separator, which operates at approximately the same pressure as the primary production separator. With this, exposure of the water-condensate mixture to a high pressure drop, resulting in the formation of emulsions, is prevented. The formation of small condensate droplets in water (emulsion) in the level regulating valve is prevented by separating the mixture and by releasing pressure in separate valves. With this, acceptable oil concentrations are achievable using relatively simple add-on treatment equipment. The technique may also be used for condensate-water mixtures from the gas filter / separator and high pressure scrubbers.
Process diagram	
Basic elements	High pressure water-condensate separator

Suitable for the removal of: R = removal efficiency	**Heavy metals**	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
	☐ Cadmium		☐ Methanol		■ **Dissolved oil**	>30
	☐ Zinc		☐ Glycols		■ BTEX	>30
	☐ Lead		☐ Corrosion inhibitors		■ Benzene	>30
	☐ Mercury		☐ Anti-scale solutions		■ PAHs	>30
	☐ Nickel		■ Demulsifiers	50-100	**Dispersed oil**	**R [%]**
					■ Oil	>20
	Remarks:					

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
	Required area (extra) (LxWxH)	negligible	negligible	
	Mass (extra) (filled)	1,5 tonnes	4 tonnes	

Critical operational parameters	The technique is process integrated and should be evaluated during the development phase and is therefore mainly applicable on new offshore installations. The use of corrosion inhibitors should be minimised, since these cause emulsion formation. When using piston compressors, the lubricant-condensate mixture, which is recovered in scrubbers, may also form stable emulsions. The use of HP separation of these flows may be very effective.
Operational reliability	High

Indication of costs							
	Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]			
		present	new	present	new		
	gas platform, small	n.a.	36 000	n.a.	2 800		
	gas platform, large	n.a.	86 000	n.a.	3 400		
	oil platform	n.a.	n.a.	n.a.	n.a.		
	Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
		Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
	dissolved oil	n.a.	93	n.a.	5	n.a.	n.a.
	dispersed oil		76		4		
	zinc equivalents		226		39		
	Remarks: In the above costs, only elevated costs in comparison with an LP installation was calculated. In view of the fact that condensate pumps are not necessary in the first phase of production (when condensate production is highest), smaller pumps can usually be installed, resulting in lower investments. Costs for existing offshore installations are not relevant, since the installation would have to be shut down too long in order to allow for replacement of the water-condensate separator, and since costs for investments are relatively high.						
Cross media effects	**Air**	Less emissions because of lower energy consumption.					
	Energy	Saves energy in condensate injection pumps as long as pressure in the production separator is higher than in the pipeline.					
	Added chemicals	Less demulsifier.					
	Waste	None.					
Other impacts	**Safety**	None.					
	Maintenance	None.					
Practical experience	**General**			**Offshore**			
				Is applied frequently offshore.			
Conclusion	■ BAT			☐ Emerging Candidate for BAT			
Literature source	[1]						

<table>
<tr><td colspan="7">Table B - 7: Methanol recovery unit</td></tr>
<tr><td>Principle</td><td colspan="6">Methanol is injected on gas platforms in order to prevent hydrates. It may be recovered from produced water by means of a methanol recovery unit. The methanol-water mixture is heated up to 99 °C, then the methanol is vaporised in a distillation column. The temperature in the top of the column is maintained at approximately 75 °C by the methanol reflux. This is to prevent to much evaporation of water. After condensation, the methanol is fed back to the methanol storage tank. The methanol content of produced water, which usually does not exceed 30%, is reduced to less than 2%.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Buffer cask, heat exchanger, methanol boiler, distillation column, condensor, accumulator, transport pumps, scale inhibitor injection.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
■ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]
20-90*</td><td>Oil
☐ Dissolved oil
☐ BTEX
☐ Benzene
☐ PAHs</td><td>R [%]</td></tr>
<tr><td>Dispersed oil
☐ Oil</td><td>R [%]</td></tr>
<tr><td colspan="6">Remarks:
Removal efficiency dependent on (fluctuations in) water throughput and methanol content.</td></tr>
<tr><td>Technical details</td><td colspan="2">Platform
Produced water volume (design)
Required area (LxWxH)
Mass (filled)</td><td>Gas 1 (small)
1 m³/h
5 x 4 x 3 m
8 tonnes</td><td>Gas 2 (large)
6 m³/h
6 x 5 x 4 m
17 tonnes</td><td colspan="2">Oil 1
n.a.
(MeOH injection is rarely applied in oil production.)</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The distillation process is very much affected by to fluctuations in throughput, which affects the quality of methanol reduction. If produced water contains salts, these may be deposited in the heat exchanger and especially in the methanol boiler. In order to prevent concentration of salts in the boiler, it is recommended to establish a small throughput from the boiler to the column by means of a re-circulation line. Relatively high energy consumption unless combined with heat recovery.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">Since methanol is often injected on satellite platforms, the water production is usually irregular, which results in lower removal efficiency and low methanol quality. Salt in produced water leads to deposits in the methanol boiler, which leads to frequent shut downs for maintenance.</td></tr>
</table>

Indication of costs

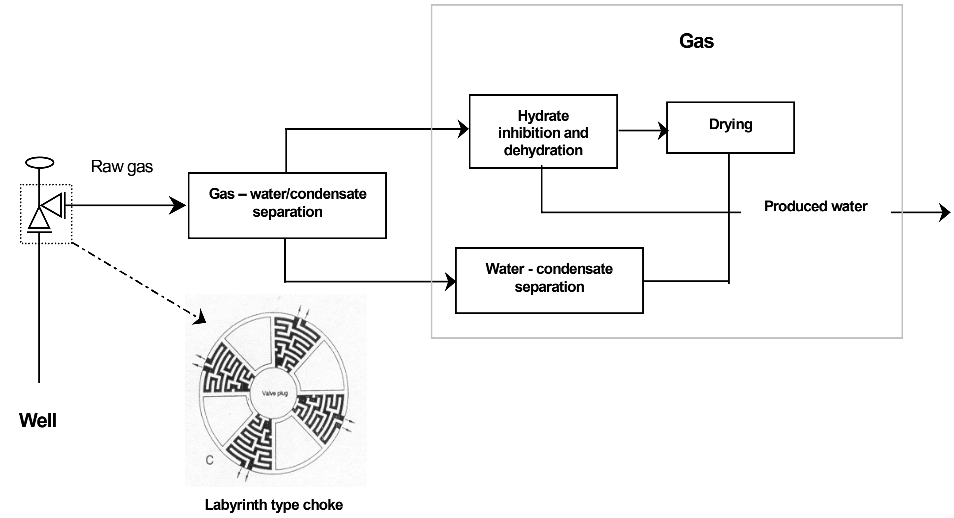
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	New
gas platform, small	905 000	752 000	291 500	171 600
gas platform, large	1 755 000	1 546 000	602 000	365 900
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
methanol	22	4,3	6,5	1,2	n.a.	n.a.

Remarks:
Methanol savings are dependent on methanol content in water and are based on a maximum content of 10-30%, average 4-10% over 1 year or average 6% over 10 years.

Cross media effects	**Air**	Energy, required for heating of produced water, for pumps and cooling, will increase air emissions, especially when diesel fuel is used.
	Energy	Energy for heating, pumps and cooling.
	Added chemicals	Scale inhibitors (to prevent salt deposition) and corrosion inhibitor (dependent on corrosivity of water and materials used).
	Waste	In the buffer cask sludge will deposit. In the heat exchanger scale will probably deposit, which will need to be removed using acids.
Other impacts	**Safety**	No significant influence.
	Maintenance	Maintenance on boiler and heat exchangers may be considerable, in the case of formation of NORM complicated procedures and higher costs arise.

	General	**Offshore**
Practical experience	Recovery of methanol is applied in a number of onshore and offshore gas production operations. Many problems in the operation of systems were encountered.	Offshore, the situation is not much different from onshore operation, except that the fluctuations in the water throughput are usually less. When needed, it is easier to install larger buffer casks.
Conclusion	☐ BAT	■ Emerging Candidate for BAT
Literature source	[1]	

Table B - 8: Labyrinth type choke valve	
Principle	With labyrinth type choke valves, gas is depressurised through friction instead of smothering as in conventional chokes. The gas speed in the choke is lower (subsonic instead of sonic). It is expected that hydrocarbon particles would then be less likely to be broken up. This advances the previous oil-water separation. This type of valve was originally developed to restrict the sound produced by chokes. On oil producing installations, labyrinth type choke valves may be used as means to minimising shear and maximising oil droplet size, rendering subsequent separation steps more efficient.
Process diagram	
Basic elements	Choke valve of the labyrinth

Suitable for the removal of: R = removal efficiency	**Heavy metals**	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
	☐ Cadmium ☐ Zinc ☐ Lead ☐ Mercury ☐ Nickel		☐ Methanol ☐ Glycols ☐ Corrosion inhibitors ☐ Anti-scale solutions ☐ Demulsifiers		■ **Dissolved oil** ■ BTEX ■ Benzene ■ PAHs	
					Dispersed oil	**R [%]**
					■ Oil	
	Remarks: This technique added to the oil-water separation process leads to improved separation. Depending on the subsequent technique, there may be a yield improvement. There is no influence on the removal of dissolved components. There is no information available regarding an improvement in yield.					

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	175 m^3/h
	Required area (LxWxH)	negligible	negligible	negligible
	Mass (extra)	negligible	negligible	negligible

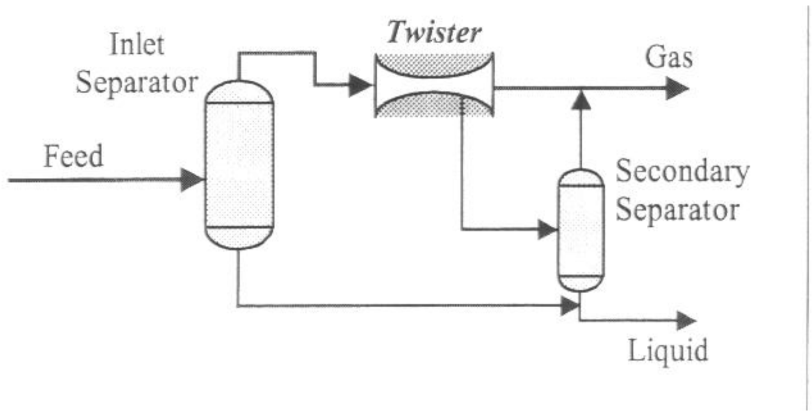
Critical operational parameters	Control of the gas speed through the valve.
Operational reliability	Uncomplicated to apply. No working parts. Choke is a standard part of platform installation.

Indication of costs					
	Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
		present	new	present	new
	gas platform, small gas platform, large oil platform	No sufficient data available for an economic analysis			

	Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
		Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
	dissolved oil dispersed oil zinc equivalents	No data available on model situation					
	Remarks:						

Cross media effects	**Air**	None.
	Energy	None.
	Added chemicals	None.
	Waste	None.
Other impacts	**Safety**	None.
	Maintenance	

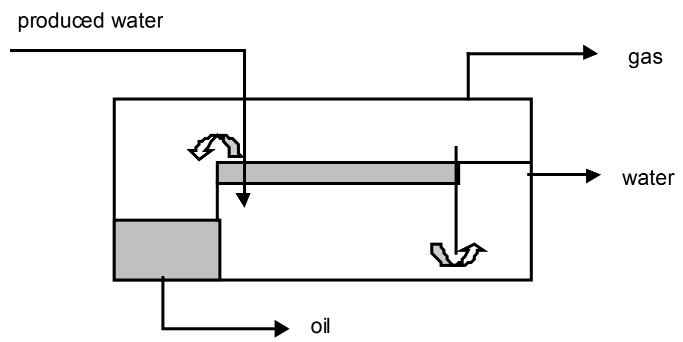
Practical experience	**General**	**Offshore**
		Field tests in 1997.
Conclusion	☐ BAT	■ Emerging Candidate for BAT
Literature source		

<table>
<tr><th colspan="7">Table B - 9: Twister supersonic separator</th></tr>
<tr><td>Principle</td><td colspan="6">Twister technology is a static piece of equipment with characteristics similar to those of a Turbo-Expansion /Compression system. Gas is expanded adiabatically in a Laval nozzle, creating supersonic velocities and low temperatures (for example a temperature at inlet of 20 °C drops mid-Twister to –50 °C). The low temperature creates a fog-like condensation, which is typically a mixture of water and heavier hydrocarbons. Chemical hydrate suppression is not required due to the very short residence time as well as the supersonic velocities within the tube. Still at supersonic velocities, the mixture of gas and liquid droplets enters the win section, generating a high velocity swirl. The resulting swirl forces the condensation outward to form a liquid film on the inner wall of the tube. The liquid film is then removed using either a co-axial tube or slits in the wall of the separation tube. The dry gas core remains as the primary stream. After inducing a weak shock wave, 70-80% of the initial gas pressure is recovered using a diffuser. Current natural gas applications are dehydration and hydrocarbon dew pointing, with bulk H2S and CO2 removal under investigation. The technology is currently suitable for offshore and onshore applications with sub-sea under investigation.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Inlet separator, Twister tube, secondary separator, heat integration of applicable</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
■ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]</td></tr>
<tr><td colspan="6">Remarks:
Twister currently (mid 2000) achieves a zero degree dew point, with lower dew points expected as the technology develops further. Dew points of – 18 degrees are expected by mid 2003. The quoted dew points depend on the specific process conditions and may differ per application.</td></tr>
<tr><td>Technical details</td><td colspan="6">Capacity: 1 to 5 mln m3/day, 100 bar per tube,
Multi tube arrangements are possible.
LxBxH (m) Typical skid: 10x3x3
Weight (tons) Typical skid: 40 tons

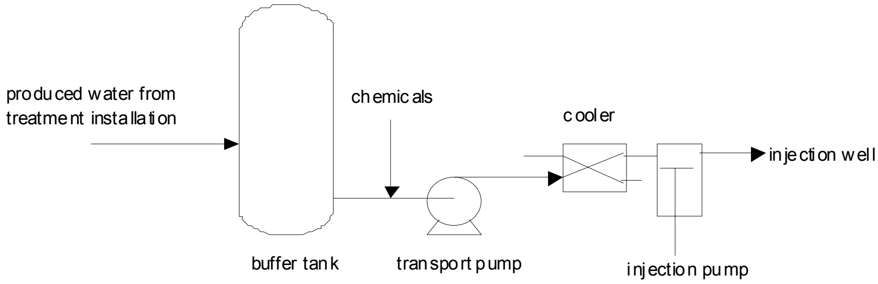
Saves space.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">Vapour composition under mid-Twister conditions must be well within product stream specifications.</td></tr>
<tr><td>Operational reliability</td><td colspan="6"></td></tr>
</table>

<table>
<tr><td rowspan="9">Indication of costs</td><td colspan="7"></td></tr>
<tr><td rowspan="2">Costs</td><td colspan="3">Investment costs (CAPEX)
[€]</td><td colspan="3">Exploitation costs (OPEX)
[€ / year]</td></tr>
<tr><td>present</td><td colspan="2">new</td><td>present</td><td colspan="2">new</td></tr>
<tr><td>gas platform, small
gas platform, large
oil platform</td><td colspan="6">No data on model situation available</td></tr>
<tr><td colspan="7"></td></tr>
<tr><td>Cost/kg removed</td><td colspan="2">Gas platform, small</td><td colspan="2">Gas platform, large</td><td colspan="2">Oil platform</td></tr>
<tr><td></td><td>Existing
[€/kg]</td><td>New
[€/kg]</td><td>Existing
[€/kg]</td><td>New
[€/kg]</td><td>Existing
[€/kg]</td><td>New
[€/kg]</td></tr>
<tr><td>dissolved oil
dispersed oil
zinc equivalents</td><td colspan="6">No data on model situation available</td></tr>
<tr><td colspan="7">Remarks:</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="6">No emissions to atmosphere.</td></tr>
<tr><td>Energy</td><td colspan="6">Fixed pressure ratio device, increasing need for wellhead compression.</td></tr>
<tr><td>Added chemicals</td><td colspan="6">No additional chemicals are needed.</td></tr>
<tr><td>Waste</td><td colspan="6">None.</td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="6">None.</td></tr>
<tr><td>Maintenance</td><td colspan="6">None.</td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="3">General</td><td colspan="4">Offshore</td></tr>
<tr><td colspan="3"></td><td colspan="4"></td></tr>
<tr><td>Conclusion</td><td colspan="3">☐ BAT</td><td colspan="4">■ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="7">[4]</td></tr>
</table>

<table>
<tr><th colspan="7">Table C - 1: Skimmer tank</th></tr>
<tr><td>Principle</td><td colspan="6">In order to reduce the content of dispersed oil in produced water, a skimmer tank can be used. Separation is based on the difference between the specific gravity of oil and water and the coalescence of oil droplets. When the retention time is sufficient, oil floats to the surface and can be separated by an overflow. This technique is suitable only for non-dissolved components such as dispersed oil with a sufficiently large particle size. Dissolved materials such as benzene and heavy metals cannot be separated using this technique. The skimmer tank or its modified version, parallel plate interceptor (PPI) or corrugated plate interceptor (CPI), is mostly used as part of a set of a number of techniques for the removal of dispersed oil.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">LP-tank with internal plates for oil-water separation and possibly a pump</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
☐ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
☐ Dissolved oil
☐ BTEX
☐ Benzene
☐ PAHs</td><td>R [%]</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
20-90</td></tr>
<tr><td colspan="6">Remarks:
Removal efficiency for oil is 100% for droplets > 150 μm, dependent on specific gravity and temperature. In practice in the offshore industry, removal seems possible up to oil contents of 200 mg/l. Additional techniques are required to achieve the performance standard for dispersed oil.</td></tr>
<tr><td>Technical details</td><td colspan="2">Platform
Produced water volume (design)
Required area (LxWxH)
Mass (filled)</td><td colspan="2">Gas 1 (small)
1 m³/h
1,2 x 2,5 x 2 m
2 tonnes</td><td>Gas 2 (large)
6 m³/h
2,4 x 2,5 x 2 m
6 tonnes</td><td>Oil 1
175 m³/h
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The orientation of the oil-water interface (level control in the tank) is determined by the difference in specific gravity. When an intermediate layer is formed, because of emulsion formation or e.g. ferrous oxides, this interface is not easy to control. The relationship between settling time and acceptable dimensions of equipment offshore limits the separation efficiency to 200 mg/l. A skimmer tank is hardly feasible for oil producing platforms, since a skimmer tank is too large in comparison with a PPI.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">High, requires regular cleaning.
Capable of handling relatively large oil content fluctuations of the influent, with limited effect on the effluent oil content.</td></tr>
</table>

<table>
<tr><td rowspan="1">Indication of costs</td><td colspan="3">Remarks:
Costs should be evaluated in comparison with the much more efficient PPI or CPI. For an installation with comparable dimensions, the costs of a skimmer tank would approximately be half.</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="2">None.</td></tr>
<tr><td>Energy</td><td colspan="2">None.</td></tr>
<tr><td>Added chemicals</td><td colspan="2">None.</td></tr>
<tr><td>Waste</td><td colspan="2">Because of a low flow velocity, relatively large amounts of sludge may deposit, mainly sand and clay, which may be slightly radioactive (NORM).</td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="2">Risk of exposure to benzene on gas producing installations during cleaning operations.</td></tr>
<tr><td>Maintenance</td><td colspan="2">Tank requires regular cleaning.</td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="2">General</td><td>Offshore</td></tr>
<tr><td colspan="2">Well known and accepted principle for separation. Much operational experience in the process industry.</td><td>Technique is mainly applied on gas producing installations.</td></tr>
<tr><td>Conclusion</td><td colspan="2">■ BAT</td><td>☐ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="3">[1]</td></tr>
</table>

<table>
<tr><td colspan="7">Table C - 2: Produced water re-injection (PWRI)</td></tr>
<tr><td>Principle</td><td colspan="6">Produced water may be re-injected in the underground through a well. The water is usually filtered, and chemicals are added in order to prevent the formation of bacteria and corrosion. Preferably, the water treatment system will be oxygen-free. When cold fracturing is applied using cooled water, the capacity of the injection pumps will be considerably less. Sometimes, produced water can be injected directly into a producing reservoir, in order to maintain pressure or in order to achieve water flooding.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Water treatment (oxygen-free), transport and/or injection pumps.
Possibly: buffer tank, injection of chemicals and coolers.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td>Heavy metals
■ Cadmium
■ Zinc
■ Lead
■ Mercury
■ Nickel</td><td>R [%]
100
100
100
100
100</td><td>Production chemicals
■ Methanol
■ Glycols
■ Corrosion inhibitors
■ Anti-scale solutions
■ Demulsifiers</td><td>R [%]
100
100
100
100
100</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs

Dispersed oil
■ Oil</td><td>R [%]
100
100
100
100

R [%]
100</td></tr>
<tr><td colspan="6">Remarks:
A 100% removal efficiency, although a small part of components will remain in filters and coolers.</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td>Technical details</td><td colspan="2">Platform
Produced water volume (design)
Required area (extra) (LxWxH)
Mass (extra)</td><td colspan="2">Gas 1 (small)
1 m^3/h
4 x 4 x 2 m
5 – 10 tonnes</td><td>Gas 2 (large)
6 m^3/h
6 x 4 x 3 m
15 – 25 tonnes</td><td>Oil 1
175 m^3/h
8 x 6 x 3 m
30-80 tonnes</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">Presence of a suitable layer for produced water re-injection and possibly suitability for cold fracturing. The quality of output of (existing) water treatment systems, e.g. content of oxygen and particles. Possibly deposition of scales and paraffins in filters and coolers. Availability of an existing well, suitable for modification for injection (leads to considerable cost reduction).</td></tr>
<tr><td>Operational reliability</td><td colspan="6">PWRI is reasonably reliable, although production and injection quantities cannot be estimated with a very high degree of certainty. The result of cold fracturing is even harder to predict. Filters require regular cleaning, the efficiency is hard to predict as is the oxygen content. Corrosion of tubing or production lines in wells is often problematic, as is deposition of salts and paraffins in tubing and lines.</td></tr>
</table>

Indication of costs

Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	11 530 000	11 380 000	3 079 000	1 888 500
gas platform, large	12 975 000	12 620 000	3 497 100	2 128 100
oil platform	6 715 000	6 100 000	2 258 600	1 478 000

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	39 054	23 954	2 592	1 578	1 146	751
dispersed oil	58 582	35 930	9 505	5 784	69	45
zinc equivalents	1 121 750	688 015	128 469	78 180	32 378	21 216

Remarks:
Depreciation in the OPEX is based on the assumption that a new well needs to be drilled, in an oil field from € 4,5 MM, in a gas field from € 11,8 MM. When an existing well is available for modification for PWRI, these costs may be reduced to € 0,9 MM – 1,8 MM and in the case of dual completion to € 1,4 MM – 2,3 MM. Costs for reservation of space and weight were not included. Costs for energy consumption for oil producing installations may be reduced considerably when cold fracturing is applied.

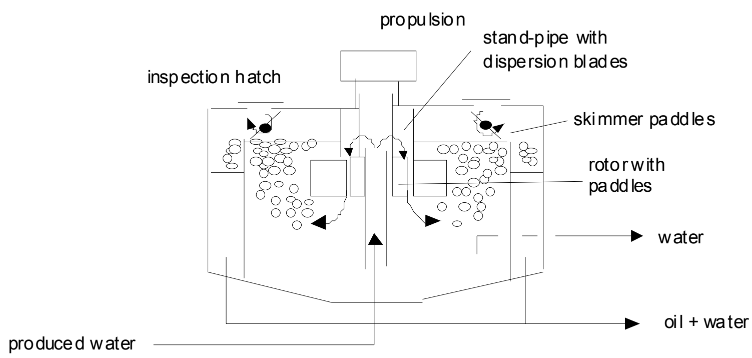
Cross media effects	**Air**	Energy for injection pumps etc. will increase air emissions, especially when diesel fuel is used.
	Energy	Energy for transport and injection pumps and possibly cooling pumps.
	Added chemicals	Dependent on the installation: scale inhibitor, corrosion inhibitor, oxygen scavenger, biocides, acids, etc.
	Waste	Sludge, which may be slightly radioactive (NORM), will deposit in the buffer tank.
Other impacts	**Safety**	PWRI influences safety very little, since the injection water hardly contains any gases.
	Maintenance	Maintenance of filters and coolers is fairly intensive, requires complicated procedures and high costs in case of NORM deposition. Possible salt deposition in tubing requires regular treatment with acids.

Practical experience	**General**	**Offshore**
	PWRI is applied onshore and offshore for a number of years in oil fields. Water production in gas fields is often too small to allow cold fracturing.	Injection in gas fields is technically feasible, but is applied rarely. Costs for investments and maintenance offshore are higher than onshore.
Conclusion	■ BAT	☐ Emerging Candidate for BAT

Literature source

[1]
[2]

Table C - 3: Dissolved gas/induced gas flotation (DGF/IGF)

Principle	In the process of gas flotation, a gas is finely distributed in the produced water. Raising gas strips oil droplets from produced water. Gas bubbles and oil form a foam on the water, which is skimmed, often by means of a paddle wheel. The foam and part of the water is skimmed into an overflow. Gas may be injected under pressure (Dissolved Gas Flotation, DGF) or by means of an impeller or pump (Induced Gas Floatation, IGF). Dissolved particles such as benzene and heavy metals are not removed, although gas injection may "strip" some volatile components. Sometimes, air is used instead of gas, in which case a major part of BTEX is also removed from the produced water. DGF/IGF usually is the "polishing" step in a multiple-step procedure to remove dispersed oil from produced water.
Process diagram	
Basic elements	Low pressure tank with impellers or pumps for gas injection

Suitable for the removal of:

R = removal efficiency

Heavy metals	R [%]	Production chemicals	R [%]	Oil	R [%]
☐ Cadmium		☐ Methanol		■ **Dissolved oil**	
☐ Zinc		☐ Glycols		■ BTEX	
☐ Lead		☐ Corrosion inhibitors		■ Benzene	0-20
■ Mercury**		☐ Anti-scale solutions		■ PAHs	
☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
				■ Oil	60-90*

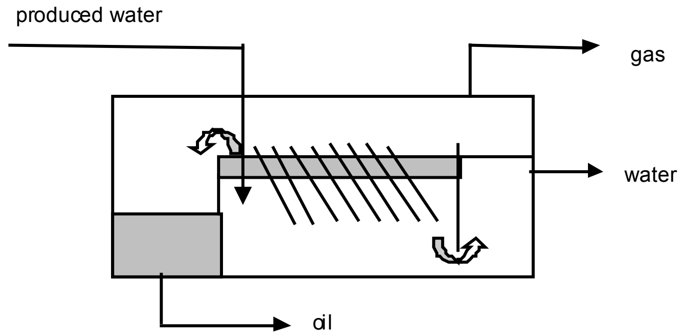
Remarks:
*: Dependent on, amongst others, specific gravity of the oil (and water) and the temperature, oil contents are reduced from 100-300 mg/l to 20-40 mg/l. Higher removal efficiencies may be achieved when retention time is longer.
**: Mercury is not removed actively, but free mercury may separate because of low flow velocity.

Technical details

Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
Produced water volume (design)	1 m^3/h	6 m^3/h	175 m^3/h
Required area (LxWxH)	1,8 x 1 x 2 m	2 x 1,5 x 2 m	10 x 2,5 x 3 m
Mass (filled)	1,4 tonnes	3 tonnes	45 tonnes

Critical operational parameters	Level control and the amount of water which is transported via the overflow, determine to a great extent the efficiency and the oil content of the effluent. Demulsifiers which are applied in the oil-water separator may have negative effects on the DGF/IGF. For this reason, some foaming agents may need to be applied. When air is used, problems may occur as a result of deposition of salts and ferrous oxides, formation of bacteria and corrosion, and is therefore rarely applied.
Operational reliability	The installation requires regular cleaning in order to remove deposited salts (scale) and other deposits (sludge).

Indication of costs	*Remarks:* In view of the dimensions of the equipment, space may need to be created by modification of existing steel constructions. This may involve considerable costs. An IGF installation with a capacity of 175 m^3/h costs approximately € 250 000 (complete installation € 435 000, possibly modification of steel constructions).	
Cross media effects	**Air**	Low pressure gas which is resolved. In order to limit air emissions (also in view of health reasons) it is recommended to install portholes in covers for visual inspection of the foam layer.
	Energy	Energy consumption approximately 5 / 15 / 50 kWh for capacity of 1 / 6 / 175 m^3/h.
	Added chemicals	Foaming agent may need to be applied.
	Waste	Because of a low flow velocity, relatively large amounts of sludge may deposit, mainly sand and clay, which may be slightly radioactive (NORM).
Other impacts	**Safety**	None.
	Maintenance	Protective clothing necessary during cleaning operations: on gas producing installations in view of benzene and possibly mercury, on oil producing installations because of NORM and sometimes mercury.
Practical experience	**General**	**Offshore**
	Technique is frequently applied for water treatment. Much operational experience in process industry.	Frequently applied offshore for removal of dispersed oil.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table C - 4: Plate interceptors (PPI/CPI)	
Principle	In order to reduce the dispersed oil content in produced water, a parallel plate interceptor (PPI) or corrugated plate interceptor (CPI) may be applied. Separation is based on the difference between the specific gravity of oil and water and the coalescence of oil droplets on the plates. Since the distance between the plates is small, small oil droplets need to rise over a short distance, allowing for separation after a relatively short retention time. On the plates small oil droplets coalescence to larger droplets and therefore rise easier to the water surface. In CPIs, the undulating plates are almost horizontal. Larger oil droplets float to plates above through holes in the lower plates. When the oil layer becomes thicker, oil flows over and is redirected into the process. This technique is applicable only for non-dissolved components such as dispersed oil with sufficient particle size. On oil producing installations, this technique may form part of a series of techniques for the removal of dispersed oil. On gas platforms, this technique sometimes suffices to achieve the performance standard.
Process diagram	
Basic elements	LP-tank with internal pack of plates and pump

Suitable for the removal of: R = removal efficiency	**Heavy metals**	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
	☐ Cadmium ☐ Zinc ☐ Lead ☐ Mercury ☐ Nickel		☐ Methanol ☐ Glycols ☐ Corrosion inhibitors ☐ Anti-scale solutions ☐ Demulsifiers		☐ **Dissolved oil** ☐ BTEX ☐ Benzene ☐ PAHs	
					Dispersed oil	**R [%]**
					■ Oil	80-95

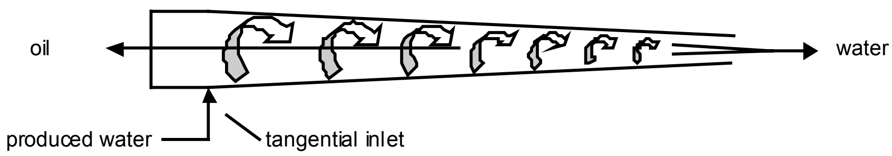
Remarks:

Removal efficiency for oil is 100% for oil droplets > 35 µm, dependent on specific gravity and temperature. In the offshore industry removal efficiencies up to 95% are achieved (from 1 000-4 000 mg/l to 100-300 mg/l). A pack of balls in the inlet compartment may raise removal efficiency considerably.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	175 m^3/h
	Required area (LxWxH)	2,5 x 0,6 x 1,8 m	2,5 x 1,2 x 2,1 m	2,3 x 5 x 3,5 m
	Mass (filled)	2,5 tonnes	5,5 tonnes	38 tonnes

Critical operational parameters	Level of oil-water interface in the PPI is critical for adequate operation. Separation efficiency is dependent on retention time, stability of the emulsion and temperature. Additional techniques are required in order to achieve the performance standard.
Operational reliability	High but requires regular cleaning. Capable of handling relatively large oil content fluctuations of the influent, with limited effect on the effluent oil content.

Indication of costs	*Remarks:* Dimensions and weight for a PPI for 175 m^3/h are presented for 1 installation. In practice, a second PPI may need to be installed as standby equipment. For this reason, on oil producing installations it is recommended to divide the required capacity over a number of PPIs in order to allow for cleaning. The PPI described costs approximately € 400 000 (fully installed).	
Cross media effects	**Air**	Energy for oil pump will increase air emissions.
	Energy	Energy consumption for oil pumps.
	Added chemicals	None.
	Waste	Because of a low flow velocity, relatively large amounts of sludge may deposit, mainly sand and clay, which may be slightly radioactive (NORM).
Other impacts	**Safety**	Risk of exposure to benzene on gas producing installations during cleaning operations.
	Maintenance	Pack of plates requires regular cleaning.
Practical experience	**General**	**Offshore**
	Well known and accepted principle for separation. Much operational experience in the process industry.	Technique is frequently applied on oil producing installations, but also on gas platforms.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table C - 5: Hydrocyclones	
Principle	Oil-water separation in hydrocyclones is based on centrifugal forces and the difference between specific gravity of oil and water. Produced water is injected under pressure tangentially. The shape of the cyclone causes an increase of speed, resulting in large centrifugal forces and separation of oil and water. The heavier water will move in a vortex towards the exit of the cyclone, whereas the lighter oil will move in a secondary vortex in the centre of the cyclone towards the inlet. Dissolved components, such as benzene and heavy metals will not be removed. Recently, rotating cyclones were developed, which are a 'compromise' between a hydrocyclone and a centrifuge. Rotating cyclones have higher removal efficiencies than a static hydrocyclone. See also Table C - 7 on centrifuges.
Process diagram	
Basic elements	Hydrocyclone and the required intake and outlet pipes. For high capacity applications, a number of cyclones are placed in parallel and integrated into one set of equipment.

Suitable for the removal of: R = removal efficiency	**Heavy metals** ☐ Cadmium ☐ Zinc ☐ Lead ☐ Mercury ☐ Nickel	**R [%]**	**Production chemicals** ☐ Methanol ☐ Glycols ☐ Corrosion inhibitors ☐ Anti-scale solutions ☐ Demulsifiers	**R [%]**	**Oil** ☐ **Dissolved oil** ☐ BTEX ☐ Benzene ☐ PAHs	**R [%]**
					Dispersed oil ■ Oil	**R [%]** Up to 98
	Remarks: Removal efficiency for oil is up to 98% for droplets > 15 - 30 µm, resulting in effluent dispersed oil contents of 60 mg/l (static cyclone) and 40 mg/l (rotating cyclone). When the oil content in the inlet is more than 1.000 mg/l, effluent oil contents may be considerably higher.					

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h/	175 m^3/h
	Required area (LxWxH)	0,8 x 2,5 x 1 m	1 x 3 x 1,2 m	3 x 4 x 1,7 m
	Mass (filled)	0,7 tonnes	1,7 tonnes	9 tonnes

Critical operational parameters	Disadvantage is that only large particles (>15 µm) can be removed, depending on the specific gravity of the oil. Oil-water emulsions can hardly be treated, neither can particles which are covered by an oil layer and which are neutrally buoyant. Rotating cyclones can remove particles up to 5 µm. In order to allow for adequate operation of hydrocyclones, a constant inlet pressure and constant flow is required. The process could therefore be affected by the presence of gas.
Operational reliability	The system is robust and compact. Usually, subsequent treatment techniques are installed in order to comply with the performance standard for dispersed oil. Since the oil content is highly dependent on the throughput, the system is less reliable when fluctuations in the process occur. It is recommended to divide the required capacity over multiple cyclones. A rotating cyclone is vulnerable and may require frequent maintenance because of rotating parts.

Indication of costs

Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	Present	new	present	new
gas platform, small	n.c.	n.c.	n.c.	n.c.
gas platform, large	n.c.	n.c.	n.c.	n.c.
oil platform	790 000	650 000	248 700	147 100

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dispersed oil	n.c.	n.c.	n.c.	n.c.	38	22

Remarks:

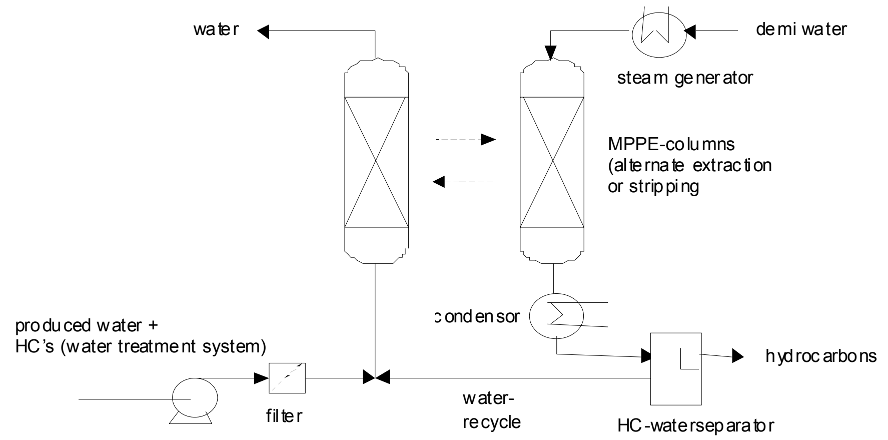
Cross media effects	**Air**	Comparable to other techniques, in view of energy consumption.
	Energy	Energy for pumps to pressurise influent, 24-30 kW (0,2 kWh/m^3).
	Added chemicals	None.
	Waste	The ‘heavy phase’ (sand etc.) and depositions in equipment (scaling), possibly slightly radioactive (NORM).
Other impacts	**Safety**	None.
	Maintenance	Relatively little, although scale may deposit on hydrocyclones.

Practical experience	**General**	**Offshore**
	Well known and much used principle for separation. Much operational experience in the process industry.	Much experience in offshore oil-water separation. Has a long history of development.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table C - 6: Macro porous polymer extraction (MPPE) (end stream)

Principle	On gas platforms, hydrocarbons can be removed from produced water from the glycol regeneration process using Macro Porous Polymer Extraction (MPPE). Water from the glycol regeneration is directed through a column packed with a bed of MPPE material. An extraction fluid, immobilised in the MPP matrix, extracts hydrocarbons from the water phase. Treated water can be discharged immediately. Prior to reaching the (maximum) required effluent concentration, the feeds are led through a second column, the first column is regenerated with low-pressure steam. Once the second column is saturated, the feeds are switched back to the first column. After a second cycle, the feeds are redirected to the first column again. A characteristic cycle lasts 1 to 2 hours. Steam and hydrocarbon vapours are condensed, and may easily be separated because of the high concentration of hydrocarbons. Hydrocarbons are led to the condensate treatment system, the small amount of water is redirected into the installation and treated.

Process diagram



Basic elements	2 columns filled with MPPE material, condenser, settling tank , steam generator (electric).

Suitable for the removal of:

R = removal efficiency

Heavy metals	R [%]	Production chemicals	R [%]	Oil	R [%]
☐ Cadmium		■ Methanol	>99 *	■ **Dissolved oil**	>99
☐ Zinc		☐ Glycols		■ BTEX	>99
☐ Lead		■ Corrosion inhibitors	**	■ Benzene	>99
■ Mercury	?	☐ Anti-scale solutions		■ PAHs	>99
☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
				■ Oil	>99*

Remarks:

The removal efficiency of benzene and other dissolved hydrocarbons, including TEX, is very high: reductions of 2 000-3 000 mg/l to < 1 mg/l are possible. The removal of mercury during a test operation was not sufficiently founded.

*: if present

**: the hydrophobic part is removed.

Technical details

Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
Partial flow (design)	0,05 m^3/h	0,1 m^3/h	
Required area (LxWxH), incl. steam generator	1,5 x 2 x 2,5 m	2 x 3 x 3 m	
Mass (filled)	2,5 tonnes	5 tonnes	

Critical operational parameters	The MPPE bed may be blocked by particles and salt depositions (scale), which may render a filter or other pre-treatment step necessary. In order to prevent salt and metal depositions, the water should remain free of oxygen as much as possible. The MPPE material should be replaced yearly in view of activity loss and clogging. The feed water for the steam generator should be demineralised. Longer hydrocarbons (> C_{20}), which are inevitably present, will pollute the MPPE material.
Operational reliability	The process is not very much affected by fluctuations in flow or BTEX-concentrations and can be fully automated (remote control). It is therefore also suitable for satellite platforms. Aliphatic contents up to 150 mg/l have little effect on operation of the system.

Indication of costs

Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	514 000	431 000	191 800	126 200
gas platform, large	618 000	518 000	254 000	175 500
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
benzene	2 703	1 778	209	145	n.a.	n.a.
BTEX	2 433	1 600	177	122		
dispersed oil	9 123	6 002	1 726	1 193		

Remarks:
Costs including replacement of MPPE extraction fluid.

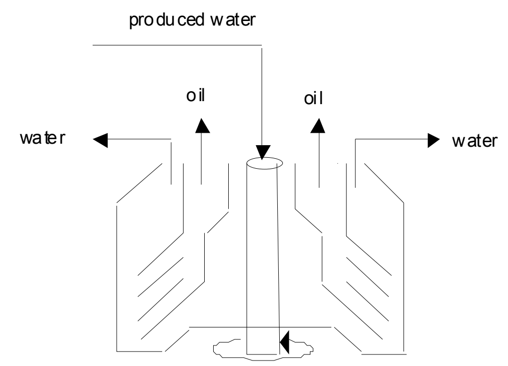
Cross media effects	**Air**	Required energy will lead to increased air emissions.
	Energy	Electricity for steam generation (3,5 kg low pressure steam per m^3 water) and for pumps (total for 0,2 / 1,4 m^3/h resp. 28 / 90 MWh/year).
	Added chemicals	Extraction fluid is consumed very slowly, and is transported with the BTEX via the separator. Possibly chemicals for demineralisation of feed water for low pressure steam production.
	Waste	The MPPE bed should be replaced every year. In case of NORM deposition, complicated procedures and high costs. Pre-treatment filters every 2 months (dependent on filter type and produced water composition).
Other impacts	**Safety**	None.
	Maintenance	Maintenance is strongly dependent on level of clogging.

Practical experience	**General**	**Offshore**
	Operational experience with MPPE-process in industrial waste water treatment. Successful treatment (partial flow and end flow) of produced water at TFE in Harlingen, the Netherlands.	Field tests on partial flow in the Netherlands (no aliphatic hydrocarbons or corrosion inhibitor) and on end stream (Shell, Statoil). Further testing required.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1] [6]	

Table C - 7: Centrifuge

Principle	A centrifuge may be used in order to reduce the dispersed oil content in produced water. Oil-water separation in a centrifuge is based on centrifugal forces and the difference in specific gravity of oil and water. Degassed produced water is injected into the centrifuge where it is brought in rotation. Water will collect at the outside of the centrifuge, oil will collect in an inner layer. Oil and water are removed separately, under controlled conditions. An oil-water interface needs to be maintained. Oil is pumped back into the process, water is discharged. A centrifuge allows for separation of smaller oil droplets than a hydrocyclone. The energy consumption is higher. Centrifuges are usually applied as a polishing step when the performance standard cannot be achieved. On oil producing installations the use of centrifuges may be useful to clean skimmings from degassers and induced gas flotation units, thereby avoiding build up of sludges.

Process diagram



Basic elements	

Suitable for the removal of:	**Heavy metals**	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
	☐ Cadmium		☐ Methanol		■ **Dissolved oil**	*
R = removal efficiency	☐ Zinc		☐ Glycols		■ BTEX	*
	☐ Lead		☐ Corrosion inhibitors		■ Benzene	*
	☐ Mercury		☐ Anti-scale solutions		■ PAHs	*
	☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
					■ Oil	95

Remarks:

Removal efficiency for oil is 100% for droplets > 3 µm, depending on specific gravity and temperature. Removal of dispersed oil from 400 mg/l to 40-10 mg/l.

Dissolved components (heavy metals, benzene) will not be removed.

*: In the case of high aromatic hydrocarbon content, e.g. in case of process malfunction, part of the aromatic hydrocarbons will be removed via the condensate.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	175 m^3/h
	Required area (LxWxH)	2 x 1,2 x 2 m	2,3 x 1,5 x 2,8 m	n.a.
	Mass (filled)	2,1 tonnes	3,1 tonnes	

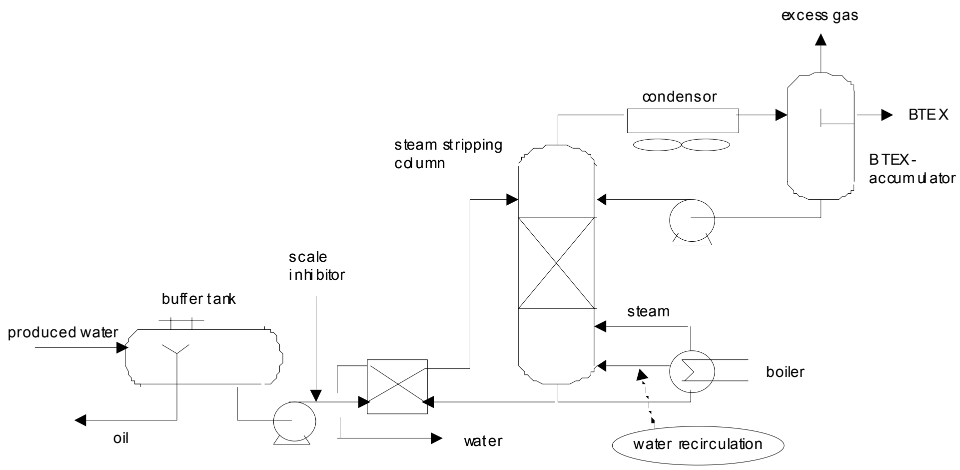
Critical operational parameters	Especially suitable for small water streams. Relatively high energy consumption. Requires water degassing prior to feed. Use of corrosion resistant materials is recommended, especially in cases of high temperature or water which contains oxygen.
Operational reliability	Centrifuges require frequent cleaning (contamination) and maintenance. A second centrifuge is often installed as standby equipment.

Indication of costs	**Costs**	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
		present	new	present	new
	gas platform, small	235 000	175 000	83 000	49 500
	gas platform, large	395 000	310 000	162 400	108 600
	oil platform	n.a.	n.a.	n.a.	n.a.

	Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
		Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
	dispersed oil	1 663	991	465	311	n.a.	n.a.
	Remarks:						

Cross media effects	**Air**	Energy for centrifuge and pump will increase air emissions.
	Energy	Energy for centrifuge and pump: 1,5 kW (small gas installation), 10 kW (large gas installation).
	Added chemicals	None.
	Waste	Deposited material in equipment (sand, clay, scale etc.) which may be slightly radioactive (NORM).
Other impacts	**Safety**	Risk of exposure to benzene during cleaning operations.
	Maintenance	Centrifuges require cleaning every few days, self-cleaning mechanisms in centrifuges are often insufficient to remove sludge.

Practical experience	**General**	**Offshore**
	Much operational experience in the processing industry.	Centrifuges are applied offshore for produced water treatment, mainly on gas producing installations.
Conclusion	■ BAT	☐ Emerging Candidate for BAT
Literature source	[1]	

Table C - 8: Steam stripping (end flow)	
Principle	Hydrocarbons can be removed from produced water by means of steam stripping. The water is fed into a packed column and brought into extreme contact with steam (known as stripping). This technique is suitable for the removal of dissolved oil (BTEX), but will also remove aliphatic hydrocarbons. Steam and hydrocarbon vapours are condensed and separated easily because of the high hydrocarbon content. Hydrocarbons that have been separated by steam can be directed to the condensate treatment system; water can be discharged.
Process diagram	
Basic elements	Buffer tank, feeding pump, heat exchanger, stripping column, condensor, BTEX-accumulator, re-circulation pump, condensate pump, (electric) re-boiler

Suitable for the removal of:

R = removal efficiency

Heavy metals	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
□ Cadmium		■ Methanol	10-80	■ **Dissolved oil**	>90
□ Zinc		□ Glycols		■ BTEX	>90
□ Lead		■ Corrosion inhibitors	*	■ Benzene	>90
□ Mercury		■ Anti-scale solutions	*	■ PAHs	>90
□ Nickel		■ Demulsifiers	*	**Dispersed oil**	**R [%]**
				■ Oil	>85

Remarks:

The expected removal efficiency for BTEX is high: reduction from 50 mg/l to < 6 mg/l, aliphatic hydrocarbons from 30 mg/l to < 3 mg/l

*: The hydrophobic part is partly removed.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
	Required area (LxWxH)	3 x 2 x 5 m	6 x 3 x 5 m	
	Mass (filled)	12 tonnes	20 tonnes	

Critical operational parameters	Since produced water usually contains salts and solid particles, problems with depositions (scale) may occur in the boiler and the heat exchanger. In order to prevent concentration of salts in the boiler, it is recommended to create a slight throughput by means of a re-circulation line from the boiler to the column. The steam line must be large enough in order to allow for equal levels in boiler and column (and above the bundle of the boiler). In order to guarantee a constant throughput, a buffer tank is required. This also provides the possibility to skim off oil, avoiding disruption of the process in the column.
Operational reliability	When the produced water contains large amounts of salts, the installation will need to be shut down regularly to enable removal of salt depositions.

Indication of costs

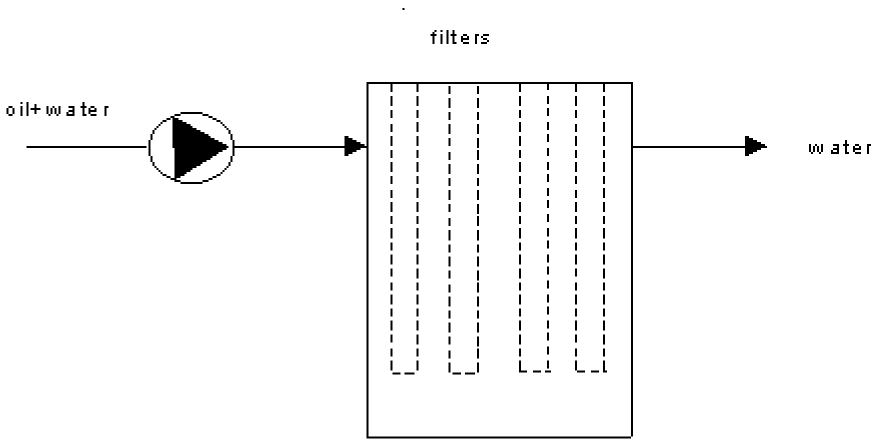
Costs	Investment costs (CAPEX) [€]		Exploitation costs (OPEX) [€ / year]	
	present	new	present	new
gas platform, small	670 000	560 000	238 000	169 200
gas platform, large	990 000	840 000	401 400	276 900
oil platform	n.a.	n.a.	n.a.	n.a.

Cost/kg removed	Gas platform, small		Gas platform, large		Oil platform	
	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]	Existing [€/kg]	New [€/kg]
dissolved oil	3 404	2 412	327	226	n.a.	n.a.
dispersed oil	3 064	2 171	277	191		
zinc equivalents	5 050	3 578	1.212	836		

Remarks:
Energy consumption is relatively high, despite the fact that part of the heat is recovered. Consumption can be reduced considerably when heat from the process or from the exhaust gases from turbines is used.

Cross media effects	**Air**	Required energy will increase air emissions. After the condensor very few gases remain.
	Energy	Approximately 40 kWh/m^3 produced water (mainly for boiler).
	Added chemicals	Scale inhibitor is needed in order to prevent deposition of salts in the heat exchanger and boiler as much as possible. Corrosion inhibitors in view of high temperatures (dependent on materials applied).
	Waste	Sludge will deposit in the buffer tank. Salt depositions need to be removed from the boiler regularly (mechanically or using acids).
Other impacts	**Safety**	No significant influence.
	Maintenance	Maintenance on boiler and heat exchanger may be considerable when the salt content in produced water is high. Complicated procedures and high costs in case of NORM deposition.

	General	**Offshore**
Practical experience	Practical experience was gained in onshore gas production operations and on partial streams offshore.	Practical experience was gained offshore on partial streams. Currently there are no offshore applications of end stream treatment operations.
Conclusion	■ BAT	□ Emerging Candidate for BAT
Literature source	[1]	

Table C - 9: Adsorption filters	
Principle	Adsorption filters may be applied for the removal of aliphatic hydrocarbons. Water is pumped through a process tank with filters. These filters contain chemically treated cellulose fibres which adsorb aliphatic hydrocarbons and, to a lesser extent, aromatic hydrocarbons. Regeneration of the filters is not possible since contaminants are adsorbed mainly chemically.
Process diagram	
Basic elements	Process tank with filters and pump.

Suitable for the removal of:

R = removal efficiency

Heavy metals	**R [%]**	**Production chemicals**	**R [%]**	**Oil**	**R [%]**
☐ Cadmium		☐ Methanol		■ **Dissolved oil**	<10*
☐ Zinc		■ Glycols	>50	■ BTEX	<10*
☐ Lead		☐ Corrosion inhibitors		■ Benzene	<10*
☐ Mercury		☐ Anti-scale solutions		■ PAHs	<10*
☐ Nickel		☐ Demulsifiers		**Dispersed oil**	**R [%]**
				■ Oil	95

Remarks:

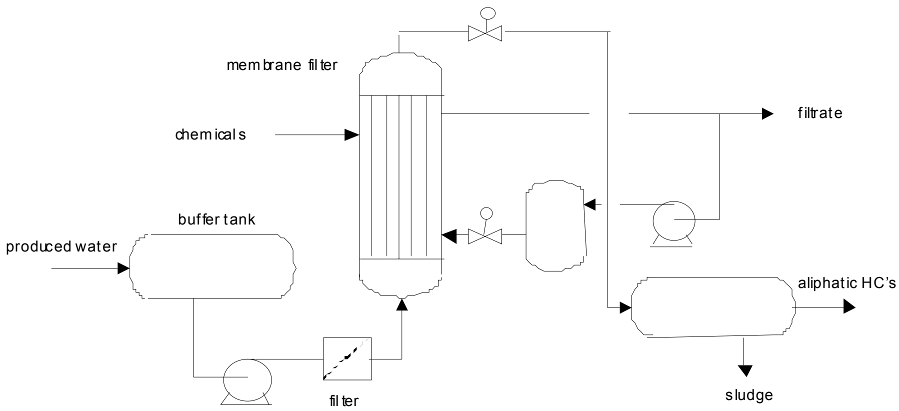
Dissolved components, excluding aromatic hydrocarbons, will not be removed. Heavy metals are only removed as solid particles > 20 µm, sometimes in the form of scale.

*: When the filter is new, this removal efficiency may be considerably higher, but when the aromatic hydrocarbons content is high, the filter will soon be saturated.

Technical details	Platform	Gas 1 (small)	Gas 2 (large)	Oil 1
	Produced water volume (design)	1 m^3/h	6 m^3/h	n.a.
	Required area (extra) (LxWxH)	1,6 x 0,8 x 2 m	2,1 x 1 x 2 m	
	Mass (extra)	1,3 tonnes	1,9 tonnes	

Critical operational parameters	Filters require frequent replacement. Particles > 20 µm will be removed but may also lead to clogging. Removal efficiency dependent on composition of produced water, and should be determined by means of field tests, i.e. on existing offshore installations.
Operational reliability	High, although frequent replacement is required. Mainly applicable in situations in cases of problems in the regular process, in order to be able to achieve the performance standard for dispersed oil.

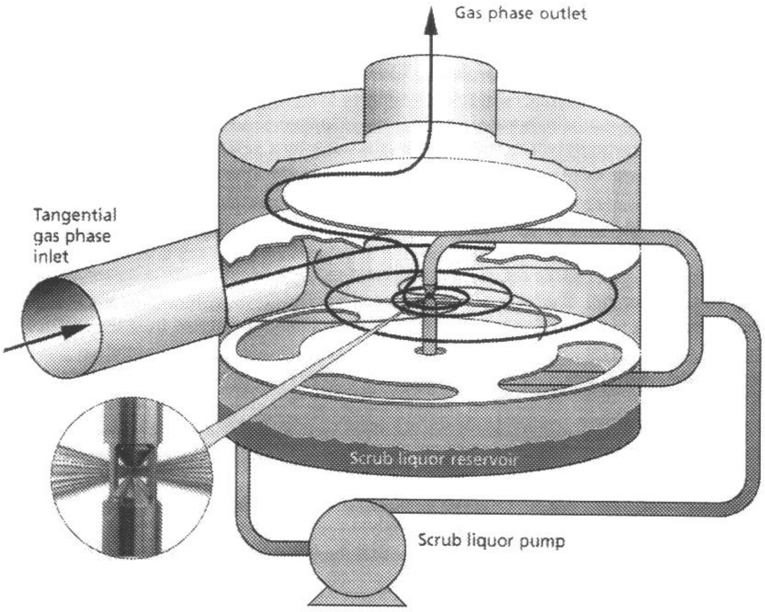
<table>
<tr><td rowspan="1">Indication of costs</td><td colspan="3">Remarks:
An adsorption filter with a capacity of 15 m^3/h costs approximately € 45 000, excluding pump, equipment and installation costs. OPEX are estimated to be € 0,4 /m^3.</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="2">Energy for feed pump will increase air emissions.</td></tr>
<tr><td>Energy</td><td colspan="2">Energy for feed pump.</td></tr>
<tr><td>Added chemicals</td><td colspan="2">None.</td></tr>
<tr><td>Waste</td><td colspan="2">Saturated filters (aliphatic hydrocarbons, clay, sand, scale which is often slightly radioactive – NORM).</td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="2">Risk of exposure to benzene when filters are replaced.</td></tr>
<tr><td>Maintenance</td><td colspan="2">Filters need frequent replacement.</td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="2">General</td><td>Offshore</td></tr>
<tr><td colspan="2"></td><td>Applied offshore on some installations.</td></tr>
<tr><td>Conclusion</td><td colspan="2">■ BAT</td><td>☐ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="3">[1]</td></tr>
</table>

<table>
<tr><th colspan="7">Table C - 10: Membrane filtration</th></tr>
<tr><td>Principle</td><td colspan="6">Aliphatic hydrocarbons may be removed by means of membrane filtration. Water (low pressure, approximately 3,5 bar) is guided along a number of ceramic or synthetic filter elements which contain pores of 0,1 – 0,2 µm. Build up of filter cake is avoided by a cross flow and a turbulent flow along the membrane surface. Part of the permeate is directed to the pressure-pulse system for cleaning of the membranes, the remaining part is discharged. The components that remain in the membrane after the pressure pulses need to be removed with chemicals periodically. The main part of aliphatic hydrocarbons and solids remain in the concentrate, which is directed to a settling tank, where the oil can be separated easily in view of the high concentrations.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Buffer tank, pre-filter, membrane filtration unit, pressure-pulse system, settling tank.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
☐ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]
*
*
*
*</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
70-90</td></tr>
<tr><td colspan="6">Remarks:
Measurements during tests revealed removal of 150 mg/l to 15 mg/l, from 110 mg/l to 30 mg/l and from 70 mg/l to 10 mg/l.</td></tr>
<tr><td>Technical details</td><td colspan="6"><table>
<tr><td>Platform</td><td>Gas 1 (small)</td><td>Gas 2 (large)</td><td>Oil 1</td></tr>
<tr><td>Produced water volume (design)</td><td>1 m^3/h</td><td>6 m^3/h</td><td>n.a.</td></tr>
<tr><td>Required area (LxWxH)</td><td>2 x 2 x 2 m</td><td>2 x 4 x 2,5 m</td><td></td></tr>
<tr><td>Mass (filled)</td><td>4 tonnes</td><td>10 tonnes</td><td></td></tr>
</table></td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">When produced water contains large amounts of salts, membranes will clog easier. Especially barium sulphate and strontium sulphate are difficult to remove chemically. Chemicals for regeneration of membranes need to be suitable for the removal of these sulphates and clay particles. Ceramic membranes are more robust and more resistant to chemicals than polymer membranes. Pre-filtration is required in order to avoid erosion of the membranes. A relatively constant flow speed (buffer tank) is needed for optimal filtration. No oxygen should be able to enter the equipment in order to avoid formation of ferrous oxides. When the permeate for the back pulse is not free of oxygen, filtration of ferrous oxides is required. Duration and frequency of pressure pulses are critical and need to be established empirically.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">During offshore testing, membrane elements were not fully regenerated, rendering this technique insufficiently reliable. It is expected that this equipment would require frequent shut down for maintenance. Furthermore, relatively intense supervision is required. Experience onshore confirm problematic removal of aliphatic hydrocarbons from salty water.</td></tr>
</table>

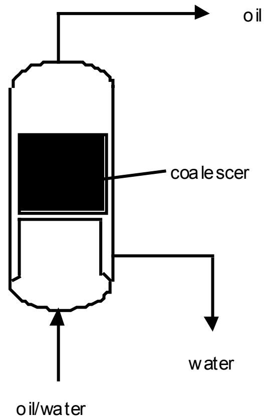
<table>
<tr><td rowspan="10">Indication of costs</td><td colspan="6"></td></tr>
<tr><td>Costs</td><td colspan="2">Investment costs (CAPEX)
[€]</td><td colspan="3">Exploitation costs (OPEX)
[€ / year]</td></tr>
<tr><td></td><td>present</td><td>new</td><td>present</td><td colspan="2">new</td></tr>
<tr><td>gas platform, small
gas platform, large
oil platform</td><td>555 000
915 000
n.a.</td><td>455 000
745 000
n.a.</td><td>216 000
448 200
n.a.</td><td colspan="2">143 900
328 000
n.a.</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td>Cost/kg removed</td><td colspan="2">Gas platform, small</td><td colspan="2">Gas platform, large</td><td>Oil platform</td></tr>
<tr><td></td><td>Existing [€/kg] | New [€/kg]</td><td></td><td>Existing [€/kg] | New [€/kg]</td><td></td><td>Existing [€/kg] | New [€/kg]</td></tr>
<tr><td>aliphatic hydrocarbons
BTEX</td><td>5 140 | 3 419
- | -</td><td></td><td>1 523 | 1 115
- | -</td><td></td><td>n.a. | n.a.</td></tr>
<tr><td colspan="6">Remarks:</td></tr>
</table>

Cross media effects		
	Air	Little effect on air emissions in view of low energy consumption.
	Energy	Estimated energy consumption: 1,2 kWh/m^3 produced water.
	Added chemicals	Chemicals for periodical cleaning and conditioning of membranes.
	Waste	Relatively large amounts of sludge in settling tank. Membranes are clogged relatively fast with sulphates which are hard to remove and may contain NORM. This would cause complex cleaning procedures or removal. Pre-filters to be regarded as waste after use.
Other impacts	**Safety**	Working with various chemicals, which may cause injury (burns). Risk of exposure to benzene when filters and membranes are replaced.
	Maintenance	Relatively high maintenance: replacement of filters and membranes, removal of sludge from settling tank.
Practical experience	**General**	**Offshore**
	Well-known and applied principle for water treatment in onshore process industry.	A number of tests were carried out offshore in the Netherlands, all tests revealed problems with membrane clogging.
Conclusion	☐ BAT	■ Emerging Candidate for BAT
Literature source	[1]	

<table>
<tr><th colspan="7">Table C - 11: V-Tex</th></tr>
<tr><td>Principle</td><td colspan="6">Gas enters the circular flat vortex chamber of a gas liquid contactor tangentially, through a series of vanes, evenly located around the chamber rim. The gas follows the circular contour of the chamber and moves inwards towards an outlet port, mounted on the central axis of the chamber. This relatively slow radial movement increases the tangential velocity, which can increase to as much as 15 m/s. At the same time, the liquid phase of the scrubbing liquor is sprayed into the centre of the chamber forming droplets, which fly out towards the chamber periphery, making contact with the rotating gas. Closing contact speeds can be high, allowing intense mass and heat transfer. As they continue to pass trough the spinning gas, the droplets develop a tangential velocity component and this generates a centrifugal acceleration which disentrains the drops by spinning them towards the chamber wall.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Stripper with integral sump mounted on a Carbon Steel skid, electrical pre-heater, centrifugal pumps</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

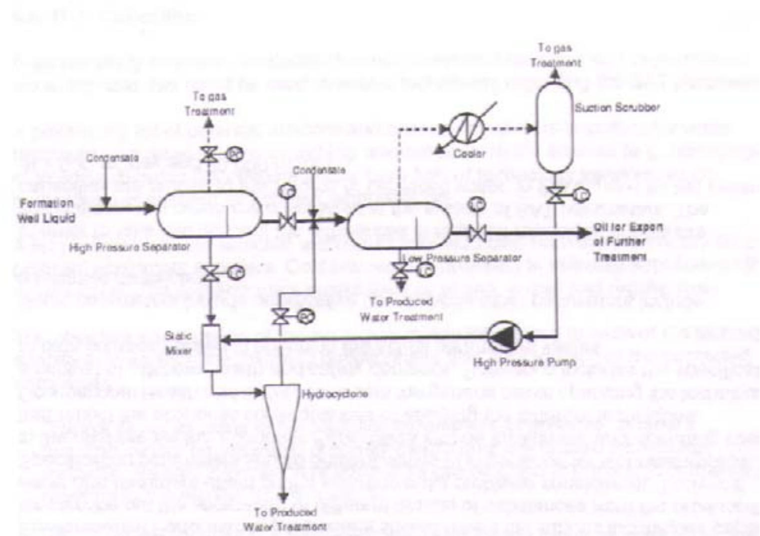
R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
■ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]</td></tr>
<tr><td colspan="6">Remarks:</td></tr>
<tr><td rowspan="4">Technical details</td><td colspan="2">Throughput (m^3/day)</td><td colspan="2">Weight (dry / wet, Te)</td><td colspan="2">Overall size l x h x w (m)</td></tr>
<tr><td colspan="2">10</td><td colspan="2">1,0 / 1,5</td><td colspan="2">2,0 x 1,15 x 2,0</td></tr>
<tr><td colspan="2">100</td><td colspan="2">2,25 / 3,0</td><td colspan="2">2,75 x 1,55 x 2,78</td></tr>
<tr><td colspan="2">500</td><td colspan="2">4,0 / 5,5</td><td colspan="2">3,75 x 2,5 x 3,75</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">The column has a design temperature range of –10 °C to 50°C, a design pressure of 3 bar. The material of construction will be carbon steel.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">The result of several trails showed that this technology was highly effective in removing a wide range of hydrocarbons (both aromatics and aliphatic hydrocarbons) from such mixtures.</td></tr>
</table>

<table>
<tr><td rowspan="9">Indication of costs</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Costs</td><td colspan="2">Investment costs (CAPEX)
[€]</td><td colspan="2">Exploitation costs (OPEX)
[€ / year]</td><td></td></tr>
<tr><td>present</td><td>new</td><td>present</td><td>new</td><td></td></tr>
<tr><td>gas platform, small
gas platform, large
oil platform</td><td colspan="5">No data on model situation available</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td>Cost/kg removed</td><td colspan="2">Gas platform, small</td><td colspan="2">Gas platform, large</td><td colspan="2">Oil platform</td></tr>
<tr><td></td><td>Existing [€/kg]</td><td>New [€/kg]</td><td>Existing [€/kg]</td><td>New [€/kg]</td><td>Existing [€/kg]</td><td>New [€/kg]</td></tr>
<tr><td>dissolved oil
dispersed oil
zinc equivalents</td><td colspan="6">No data on model situation available</td></tr>
<tr><td colspan="7">Remarks:</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="6"></td></tr>
<tr><td>Energy</td><td colspan="6"></td></tr>
<tr><td>Added chemicals</td><td colspan="6"></td></tr>
<tr><td>Waste</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="6"></td></tr>
<tr><td>Maintenance</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="3">General</td><td colspan="4">Offshore</td></tr>
<tr><td colspan="3"></td><td colspan="4"></td></tr>
<tr><td>Conclusion</td><td colspan="3">☐ BAT</td><td colspan="4">■ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="7">[3]</td></tr>
</table>

<table>
<tr><th colspan="7">Table C - 12: Filter coalescer</th></tr>
<tr><td>Principle</td><td colspan="6">Dispersed oil may be removed from produced water by means of a filter coalescer. The coalescer is usually equipped with a column packed with fine material. Small oil droplets (< 10 µm) conglomerate in the packed material to greater droplets, which are easier to separate. The technique is often used only as coalescer, i.e. to enlarge oil droplets, which can be separated in a next step. This technique is less suitable for large flows. In order to comply with the performance standard, a subsequent treatment step is required.
This technique is not suitable for removal of dissolved components as benzene and heavy metals.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">Cask packed with coalescer material.</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
☐ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
☐ Dissolved oil
☐ BTEX
☐ Benzene
☐ PAHs</td><td>R [%]</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
30</td></tr>
<tr><td colspan="6">Remarks:
A filter coalscer only removes larger oil droplets (> 10 µm) and often actual removal takes place in a next treatment step.</td></tr>
<tr><td>Technical details</td><td colspan="3">Platform
Produced water volume (design)
Required area (LxWxH)
Mass (filled)</td><td>Gas 1 (small)
1 m³/h
1 x 1 x 2 m
2 tonnes</td><td>Gas 2 (large)
6 m³/h
1,5 x 1,5 x 2,5 m
3 tonnes</td><td>Oil 1
175 m³/h
n.a.</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">Proper operation depends on droplet size of the input. Not suitable for emulsions. Pressure in coalescer preferably equal to the pressure in the next treatment step, since large differences in pressure pumps and valves may undo the results achieved in the coalescer. Applicability is often established empirically.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">Reliability is high as long as the filter pack is not contaminated.</td></tr>
</table>

Indication of costs	*Remarks:*		
Cross media effects	**Air**	None.	
	Energy	None.	
	Added chemicals	None.	
	Waste	Very little (only when pack material is replaced).	
Other impacts	**Safety**	None.	
	Maintenance	Sand, clay and scale are hard to remove, rendering frequent cleaning or replacement of the filter material necessary. Removed material may be slightly radioactive (NORM).	
Practical experience	**General**		**Offshore**
	Well-known and applied, although effect in individual situations may be hard to predict.		Tested offshore for a short period, using centrifuge as subsequent treatment step.
Conclusion	☐ BAT		■ Emerging Candidate for BAT
Literature source	[1]		

<table>
<tr><th colspan="7">Table C - 13: Ctour process system</th></tr>
<tr><td>Principle</td><td colspan="6">The Ctour Process System is based on the extraction of hydrocarbons from water using gas condensate. The gas condensate acts as extraction-solvent. The principle of the extraction process is to add an immiscible solvent in a solution that will absorb the solute (in this case dissolved oil, BTEX etc.) because of the higher affinity towards the extraction solvent. The extraction process is based on thermo dynamical equilibrium between two liquid phases and is thus dependent on the actual composition of the extraction-solvent (and of the solution). In the Ctour process the extraction solvent is the gas condensate taken from the scrubber. The actual efficiency of the extraction process will therefore depend on composition of the condensate, which in turn is dependent on the operating pressure and temperature of the scrubber.
Condensate normally extracted from a gas train scrubber, is injected upstream of the de-oiling hydrocyclones. The condensate acts as a solvent, and the oil will have a high affinity towards the condensate. The condensate and the oil form large, low-density droplets that are easily removed by the downstream hydrocyclone.</td></tr>
<tr><td>Process diagram</td><td colspan="6">
</td></tr>
<tr><td>Basic elements</td><td colspan="6">High and low pressure separators, high pressure pump, static mixer, hydrocyclone</td></tr>
<tr><td rowspan="3">Suitable for the removal of:

R = removal efficiency</td><td rowspan="2">Heavy metals
☐ Cadmium
☐ Zinc
☐ Lead
☐ Mercury
☐ Nickel</td><td rowspan="2">R [%]</td><td rowspan="2">Production chemicals
☐ Methanol
☐ Glycols
☐ Corrosion inhibitors
☐ Anti-scale solutions
☐ Demulsifiers</td><td rowspan="2">R [%]</td><td>Oil
■ Dissolved oil
■ BTEX
■ Benzene
■ PAHs</td><td>R [%]
*
*
*
*</td></tr>
<tr><td>Dispersed oil
■ Oil</td><td>R [%]
*</td></tr>
<tr><td colspan="6">Remarks:
*: Removal efficiencies of 90% (dispersed oil) and 95% (BTX, PAH) have been reported under laboratory and pilot scale conditions. Offshore tests (Norway, 2000) revealed much lower removal efficiencies, and the process is, amongst others, dependent on the composition of the condensate used for extraction (in fact the condensate may lead to an increase of BTEX under certain circumstances). CTour is not yet generally applicable for reducing the amount of aromatics in produced water from offshore installations. However, the test results are promising and it is expected that future development may resolve the current problems. There might be a need for auxiliary equipment in order to reduce the potential transfer of light component (such as BTX components) from the condensate to the discharge stream.</td></tr>
<tr><td>Technical details</td><td colspan="3">Platform
Produced water volume (design)
Required area (extra) (LxWxH)
Mass (extra)</td><td>Gas 1 (small)
1 m^3/h</td><td>Gas 2 (large)
6 m^3/h</td><td>Oil 1
175 m^3/h</td></tr>
<tr><td>Critical operational parameters</td><td colspan="6">High pressure re-circulation equipment (>10 bar) is required. Pressure in produced water must be above 10 bar. Residual condensate in the underflow of the hydrocyclone must evaporate completely in the degasser at atmospheric pressure and the given temperature of the water.</td></tr>
<tr><td>Operational reliability</td><td colspan="6">Depends on condensate composition. In the liquid state the condensate must remain in the reject line upstream of the hydrocyclone reject control valve. In the gaseous state the condensate should have the same atmospheric pressure and temperature as the produced water.</td></tr>
</table>

<table>
<tr><td rowspan="9">Indication of costs</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Costs</td><td colspan="2">Investment costs (CAPEX)
[€]</td><td colspan="2">Exploitation costs (OPEX)
[€ / year]</td></tr>
<tr><td>present</td><td>new</td><td>present</td><td>new</td></tr>
<tr><td>gas platform, small
gas platform, large
oil platform</td><td colspan="4">No data on model situation available</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td>Cost/kg removed</td><td colspan="2">Gas platform, small</td><td colspan="2">Gas platform, large</td><td colspan="2">Oil platform</td></tr>
<tr><td></td><td>Existing [€/kg]</td><td>New [€/kg]</td><td>Existing [€/kg]</td><td>New [€/kg]</td><td>Existing [€/kg]</td><td>New [€/kg]</td></tr>
<tr><td>dissolved oil
dispersed oil
zinc equivalents</td><td colspan="6">No data on model situation available</td></tr>
<tr><td colspan="7">Remarks:</td></tr>
<tr><td rowspan="4">Cross media effects</td><td>Air</td><td colspan="6">Energy to generate high pressure will increase air emissions.</td></tr>
<tr><td>Energy</td><td colspan="6">Energy to generate high pressure (10 bars).</td></tr>
<tr><td>Added chemicals</td><td colspan="6">No need for flocculants and de-emulsifiers.</td></tr>
<tr><td>Waste</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Other impacts</td><td>Safety</td><td colspan="6"></td></tr>
<tr><td>Maintenance</td><td colspan="6"></td></tr>
<tr><td rowspan="2">Practical experience</td><td colspan="3">General</td><td colspan="4">Offshore</td></tr>
<tr><td colspan="3">Not yet generally applicable, test results are promising.</td><td colspan="4"></td></tr>
<tr><td>Conclusion</td><td colspan="3">☐ BAT</td><td colspan="4">■ Emerging Candidate for BAT</td></tr>
<tr><td>Literature source</td><td colspan="7">[5]</td></tr>
</table>

2. References

1 Stand der Techniek Offshore Productiewater Olie- en Gaswinningsindustrie (Best Available Techniques Produced Water Oil and Gas Industry), CIW VI subwerkgroep SdT Offshore productiewater, 14 January 2002
2 Environmental aspects of on and off-site injection of drill cuttings and produced water, OSPAR 2001, ISBN 0 946956 69 3
3 Removal of hydrocarbons from produced water, OIC 01/8/Info.3, Oslo, 13-16 February 2001
4 Twister - A supersonic separator for the de-hydration of gas, OIC 01/8/Info.6, Oslo 13-16 February 2001
5 Background document on aromatic substances including PAH in produced water, OIC 01/8/8, Oslo, 13-16 February 2001

Annex 1: Basis for figures in fact sheets

1. Model situations

Three model situations were established, i.e.:

1. small gas installation (based on 26 gas installations with small produced water discharges);
2. large gas installations (based on 27 gas installations with larger produced water discharges);
3. oil installations (based on 7 oil installations).

For each model situation, representative produced water quality and quantity figures were established. For water quality figures, the mediane and the 90 percentile values were established for each component, whereas the average design flow was used as point of departure for quantity values. For establishment of cost figures, new and existing offshore installations were distinguished.

The following points of departure were established on the basis of a considerable amount of data. It is noted that these data may not be representative for the all produced water discharges from all types of installations in the OSPAR area; the model situations were established on the basis of a limited amount of installations in a limited area. Other model situations may need to be defined when modifications of this background document are considered.

Model situation	**Average volume m^3/h**	**Design volume m^3/h**
Gas platform, small	0,2	1
Gas platform, large	1,4	6
Oil platform	150	175

Concentrations and loads for gas platform, small

		concentrations			**load per year**	
		median	90-percentile		median	90-percentile
Volume*	m^3/u	0,2	n.a.			
Benzene	mg/l	45	250	kg/year	79	438
BTEX	mg/l	50	300	kg/year	88	526
Cadmium	mg/l	0,0025	0,250	kg/year	0,004	0,44
Mercury	mg/l	0,0011	0,004	kg/year	0,002	0,007
Lead	mg/l	0,025	2,2	kg/year	0,04	4
Nickel	mg/l	0,040	0,080	kg/year	0,07	0,14
Zinc	mg/l	1,3	90	kg/year	2	158
Aliphatic HC's	mg/l	30	40	kg/year	53	70

* average volume in 1998

Concentrations and loads for gas platform, large

		concentrations			**load per year**	
		median	90-percentile		median	90-percentile
Volume*	$m^3/$	1,4	n.a.			
Benzene	mg/l	110	520	kg/year	1 350	6 375
BTEX	mg/l	130	550	kg/year	1 600	6 745
Cadmium	mg/l	0,0025	200	kg/year	0,030	2,45
Mercury	mg/l	0,0011	6	kg/year	0,013	0,074
Lead	mg/l	0,03	9	kg/year	0,4	110
Nickel	mg/l	0,030	60	kg/year	0,37	0,74
Zinc	mg/l	2	60	kg/year	25	735
Aliphatic HC's	mg/l	30	40	kg/year	370	490

* average volume in 1998

Concentrations and loads for oil platforms

		concentrations			load per year	
		median	90-percentile		median	90-percentile
Volume	m^3/	150	n.a.			
Benzene	mg/l	1,5	1,9	kg/year	1 970	2 500
BTEX	mg/l	2,5	3	kg/year	3 285	3 940
Cadmium	mg/l	0,0004	0,0006	kg/year	0,53	0,72
Mercury	mg/l	0,00003*	-	kg/year	0,039	-
Lead	mg/l	0,01*	0,025	kg/year	13,1	33
Nickel	mg/l	0,005*	-	kg/year	6,6	-
Zinc	mg/l	0,02*	0,1	kg/year	26,3	131
Aliphatic HC's	mg/l	25	40	kg/year	32 850	52 560

* = value established by judgement, below detection limit

The concentrations referred to in the column 'median' have been used for the model situations.

2. Cost figures

For each possible measure, model situations were established (where possible / relevant), including cost figures. Capital expenses (CAPEX) and operational expenses (OPEX) were estimated on the basis of market conformity (price level 2000). Estimates were based on price indications from suppliers, designers and fitters. Furthermore, use was made of data from information and experiences in the industry and other parties involved in offshore oil and gas activities.

CAPEX

Investment estimates for each technique is based on the following costs:

- design and project management;
- equipment;
- transport;
- fitting; and
- unforeseen.

Design and project management costs are dependent on the complexity of the installations, but were estimated to be 10% of the total investments.

For each technique, the treatment system will be formed of specific equipment and other equipment, necessary for proper functioning of the apparatus. These may be buffer tanks and pumps. Prices were based on information from more than one supplier where possible.

Transport costs are important when the technique is installed on existing offshore installations. For new installations, transport costs were assumed 0.

Fitting activities are dependent on the complexity of the installation, and will differ per technique and per situation (existing or new platform, etc.).

Use of space on offshore installations involves costs. For two exemplary situations, investment for use of space on a new platform was calculated.

Part of the investment costs cannot be estimated. Therefore, unforeseen costs have been incorporated in the calculations. On existing offshore installations, more unforeseen circumstances may be expected, therefore these costs may be higher than on new installations. For existing offshore installations unforeseen costs were estimated to be 15% of the total costs, for new installations these are estimated to be 10%.

Capital expenses of investments were calculated on the basis of the annuity method, taking account of the following situations:

		New platform	Existing platform
Depreciation period	[years]	10	5
Interest rate	[%]	10	10
Annuity	[% of total investment]	16,3	26,4

Total investment costs are the sum of design and project management costs, equipment, transport, fitting and unforeseen costs. The calculations above are based on the assumption that no rest value will remain. Re-use of parts is limited, rest value will usually be the scrap value and is assumed zero.

OPEX

All costs were based on the price level of the reference year 2000 (the Netherlands). For future estimates, price escalations of approximately 3% per year should be taken into account. Points of departure for calculation of yearly operational costs are presented in the table below. For each technique and model situation, yearly operational expenses were calculated (where possible).

	New offshore installation	**Existing offshore installation**
depreciation	0,163 x I	0,264 x I
maintenance	€/m^3 (i.s./e.f.) x Q	€/m^3 (i.s./e.f.) x Q
spare parts	€/m^3 (i.s./e.f.) x Q	€/m^3 (i.s./e.f.) x Q
use of chemicals	€/kg x kg/m^3 (i.s.) x Q	€/kg x kg/m^3 (i.s.) x Q
use of potable water	€ 3,40 /m^3 x amount m^3/year (i.s.)	€ 3,40/m^3 x amount m^3/year (i.s.)
other regular uses	i.s.	i.s.
operation (crew)	€ 32,--/uur x amount hours/year (e.f.)	€ 32,--/hour x amount hours/year (e.f.)
energy	€ 0,14/kWh x kWh/year (i.s.)	€ 0,14/kWh x kWh/year (i.s.)
Removal of sludge • regular quantity • small quantity (< 3 500 kg/year)	€ 365,--/ton x 1 000 kg/ton x amount kg sludge/m^3 (e.f.) x Q; € 680,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q;	€ 365,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q; € 680,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q;
Mercury containing sludge	€ 1 140,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q	€ 1 140,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q
Radioactive waste	€ 15 000,--/ton x 1 000 kg/ton x amount kg m^3 (e.f.) x Q	€ 15 000,--/ton x 1 000 kg/ton x amount kg/m^3 (e.f.) x Q

I : total investment costs in Euro (CAPEX);

Q : yearly treatment flow in m^3/year;

i.s. : information supplier;

e.f. : best estimate by authors fact sheet.

Usually, yearly OPEX will amount approximately 35 – 45% of the CAPEX (I).