Investigation of the potential to reduce the operating costs through successful implementation of field re-development projects

Master Thesis

of

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Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Vienna, May 2013

Sergej Gall

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Abstract

The Program Management of OMV Austria Exploration & Production (E&P) in Gänserndorf handles several oilfield re-development projects in the area of Matzen (Lower Austria) and its close proximity. The ongoing Mature Oilfield Re-development (MORE) program in Matzen pursues the goal to increase the Net-Present-Value by implementing new recovery strategies to accelerate the oil production and to realize possible reserves.

The research questions of this thesis should be seen as arising out of, and contributing to, the discussion of optimizing operating costs issues in re-development projects.

The theoretical part of the thesis starts with the description of the Matzen oilfield and its history, the Mature Oilfield Re-development (MORE) program, as well as the ongoing re-development projects in Matzen and Erdpress. The goals, objectives and approaches of the MORE program are characterized and different cases with different amounts of investments are presented.

The following part deals with the literature review and includes the main cost accounting methods used in the oil and gas industry. The differentiation between Capital expenditures (CAPEX) and Operational expenditure (OPEX) as well as the distinction of production costs and lifting costs are also provided. A further focus of this review is the life-cycle-costing method. This is included to provide an overview of this method, which will then be used at the practical part. The method is chosen because it applies the generic logic of the replacement cost approach and extends this through dynamic consideration of the total assets related costs over the life span of the assets.

A further aspect of the thesis was given by OMV Upstream Accounting. In the course of this, costs are defined whether to be capitalized or expensed. Another issue is based on OMV Cost Accounting. The cost structure of OMV is described, using the structure of SAP. Moreover, the allocation of costs is defined and exemplarily described.

A major step of the thesis is to show the breakdown of costs and how they are composed. For that purpose, a split of OPEX, production costs, lifting costs and its individual components is presented in hierarchically structures. By the end of the OPEX split, an example of the OPEX distribution, based on the costs of 2012 from the Matzen oilfield, is performed.

The main focus of the practical part of this thesis lays on the optimization of OPEX. For that intent a differentiation between electric submersible pumps (ESP) and sucker rod pumps (SRP) is revealed from an economical point of view. Therefore, the method of life-cycle-costing is used to show the differences of both pumps based on costs for acquisition, energy and maintenance. For the calculation the dependencies between the costs for energy and maintenance with the production rate and the reliability are also taken into account. A detailed analysis of these parameters is performed, to come out with the main result that ESPs have lower long-term costs than SRPs for rates higher than 200 m^3/d.

Due to the fact that an increase of the gross production rate, leads to a growth of the water rate, water management is identified as a further research issue of the thesis. Therefore, two new water treatment systems (hydrocyclones and tanks) and one for the existing water treatment system are calculated to demonstrate the different amount of costs. The results of this analysis underline that both new water treatment systems can reduce the water treatment costs.

In the last step the total OPEX for the Bockfließ Area is calculated, using scenarios of different water treatment systems.

Finally it can be stated that the total OPEX are mainly affected by the costs for energy, well interventions and water treatment. Total OPEX can be reduced by applying new water treatment methods compared to the existing system. Talking in numbers, this means 57,17 EUR/m³ (9,09 EUR/bbl) of OPEX for the method with hydrocyclones, 54,85 EUR/m³ (8,72 EUR/bbl) of OPEX for the method with tanks and 62,27 EUR/m³ (9,90 EUR/bbl) of OPEX for the existing system.

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2P	Proved + probable reserves
3P	Proved + probable + possible reserves
API	American Petroleum Institute
A-oil	Asphaltic oil
P-oil	Paraffinic oil
bopd	Barrels of oil per day
bwpd	Barrels of water per day
CAPEX	Capital Expenditures
E&P	Exploration & Production
Erd	Erdpress
ESP	Electrical Submersible Pump
FASB	Financial Accounting Standards Board
FC	Full Costing
FDE	Field Development Erdpress
GOSP AU	Gas and Oil Separation Plant Auersthal
GOSP MA	Gas and Oil Separation Plant Matzen
GWST	Gewinnungsstation (German for GOSP)
HSEQ	Health Safety Environment Quality
KPI	Key Performance Indicator
LCC	Life-Cycle-Costing
LOEMST	Lebendöl-Messstation – life oil metering station
LOESST	Lebendöl-Sammelstation – life oil collecting station
MA	Matzen
MM	Million
MORE	Mature Oilfield Re-Development
MTBF	Mean Time Between Failure
MTP	Mid Term Plan
N.B.	Nota Bene (remark)
NFA	No Further Action
NPV	Net Present Value
OOIP	Original Oil In Place
OPEX	Operational Expenditures

PC	Profit Center
PPS	Parallel Plate Separator
PtL	Produce the Limit
RD	Re-Development
RDE	Re-Development Erdpress
RDM	Re-Development Matzen
RoR	Rate of Return
SE	Successful Effort
SRP	Sucker Rod Pump
TCO	Total Cost ofs Ownership
TF AU	Tank Farm Auersthal
TH	Tortonian Horizon
UGS	Underground Gas Storage
VDMA	Verband Deutscher Maschinen- und Anlagenbau
WI	Well Intervention
WO	Workover
WC	Water Cut
WTP	Water Treatment Plant

1 Introduction

1.1 Initial situation and goals

The Program Management of OMV Austria Exploration & Production GmbH came up to the Department of Economic and Business Management of the Montanuniversität Leoben and provided a Master Thesis about the operating costs and development of them if field re-development projects are implemented.

These projects are initiated to increase the net present value (NPV) of an asset. To be able to know how the operating costs will develop after the implementation of such re-development projects, OMV Austria Exploration & Production GmbH supplied a Master Thesis about that topic.

Due to the high maturity of the Matzen oilfield more and more costs have to be expended to struggle against declining oil rate. The purpose of the Mature Oilfield Re-development (MORE) program is to increase the NPV by implementing new recovery strategies to accelerate the oil production and to realize possible reserves. In the course of the MORE program several considerations should be evaluated and reviewed:

- Evaluation of the cost structure in OMV Austria
- Review of OMV OPEX split
- Investigation of the main cost drivers of OPEX
- OPEX optimization
- OPEX forecast in the Bockfließ Area

The performance requirements on the part of OMV – Program Management were to create clarity and transparency and give an insight into cost structuring and cost splitting. The task was to investigate OMV oilfields, especially the Matzen oilfield and in particular the water management of the 16th TH (Tortonion Horizon) – Bockfließ Area. Through this investigation, an optimization for particular well planning as well as optimization of the water management for the 16th TH was elaborated. The way of proceeding thereby was to collaborate with the Controlling Department to illustrate figurative a deciphering of the SAP structure both total cost structure and OPEX split.

After association with the Project Management, the situation of the Bockfließ Area was worked out. Therefore, the conversion of water treatment within the gas and oil separation plant (GOSP) in Auersthal should be explained and methods of cost reduction are supposed to support the planning of the Bockfließ Area.

The strategy and procedure, how these tasks are solved, is shown in the following.

1.2 Procedure

After a short remark of the Matzen oilfield and its individual re-development projects, a literature review is given in chapter 2 about cost accounting and its goals. The individual costs and the common methods of cost accounting for the oil and gas industry are explained. In another subsections, the terms of capital expenditures and operating expenditures and its differences are explained. Furthermore, there will be another distinction between production costs and lifting costs for the petroleum industry. An additional focus of this thesis was on life-cycle-costing (LCC). The reason for this is due to the fact that LCC provides a meaningful tool to select the best alterative out of multiple alternatives. By the end of literature review, this thesis is responsive to OMV cost accounting and OMV upstream accounting. The focus thereby is on detailed definitions for OMV like the difference of workovers (WO) and well interventions (WI) and the difference, whether costs are capitalized or expensed. Cost accounting focuses on cost structuring and cost allocation of OMV.

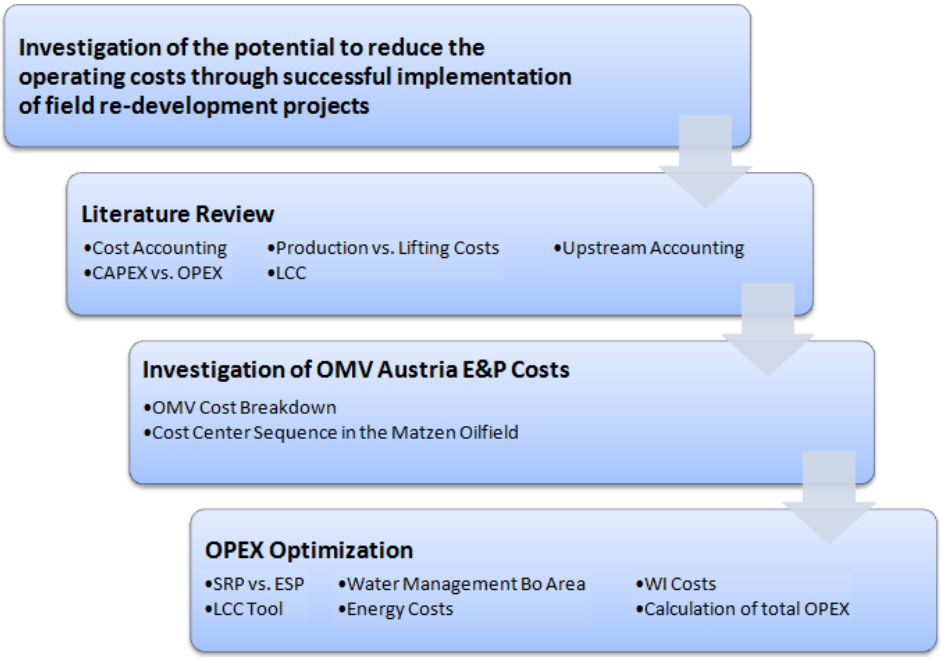

Figure 1: Procedure & Strategy of the Thesis

In chapter 3, the OMV cost breakdown will be investigated. Thereby the OPEX split and the split of its individual sub-costs is shown.

- Labor
- Service
- Material & Energy
- Other Operating Costs
- Allocations

Furthermore, a cost distribution from the Matzen oilfield from the year 2012 can be seen. Another focus of chapter 3 was on the distinction between production costs and lifting costs.

All the important cost centers of the Matzen oilfield and its interaction are explained after discussion with the responsible cost center supervisors.

In consequence of the need to rise the gross production rate to fulfill the enhancement of NPV it is apparent that not only CAPEX will accrue. There will also be an increase of operating costs, attributable to the large amount of water that has to be treated and re-injected. Another issue of increasing OPEX will be the rising energy demand due to an additional deployment of electric submersible pumps (ESP).

Chapter 4 provides a more practical section where the difference between sucker rod pumping and electric submersible pumps from an economical point of view is shown. Thereby, parameters like MTBF, energy costs, well intervention costs and oil and water treatment costs were empirically determined. Another emphasis in this section is on the LCC tool. It was generally generated and can be adopted to determine costs for several components or facilities. As an example in this chapter, the cost differences between electric submersible pumps and sucker rod pumps are shown.

Another sub-chapter is about the water management of the 16^{th} TH – Bockfließ Area. Thereby, the field infrastructure and the conversion of GOSP Auersthal are described to understand the background of the necessity of water management. For the purpose of water management, three scenarios were elaborated. One is the treatment of water with hydrocyclones and the second is based on water treatment with tanks & parallel plate separators (PPS). The third scenario was elaborated based on the old system to show the differences to the newer methods. Independent on the type of water treatment, an injection system will be required to re-inject the processed formation water into the subsurface and therefore, costs were determined. After calculating water treatment costs, the total OPEX of the Bockfließ Area were calculated, based on the gross production rate increase of pre-defined wells defined by the Project Management in Gänserndorf. For this purpose, the factors mean time between failure (MTBF), oil & water treatment costs, energy costs and well intervention costs influence total OPEX of a well and subsequently of a total field.

2 The MORE program

2.1 Overview

Figure 2 shows the location of the Matzen oilfield, a giant field and one of the largest on-shore oilfields in Europe. The field has an extent of about 10 km in length and 5 km in width. Geologically speaking, it is part of the Vienna Basin and located about 20 km in the north-east of Vienna, where OMV is producing since the early 1950s. Since then, a variety of activities had been done to struggle against production rate decline. To support the economic life of these mature fields OMV introduced the MORE program where some re-development projects are already implemented and some are currently (effective April 2013) in the planning phase. In the figure below, the ongoing re-development projects are illustrated:

- RDM – re-development Matzen
- RDE – re-development Erdpress

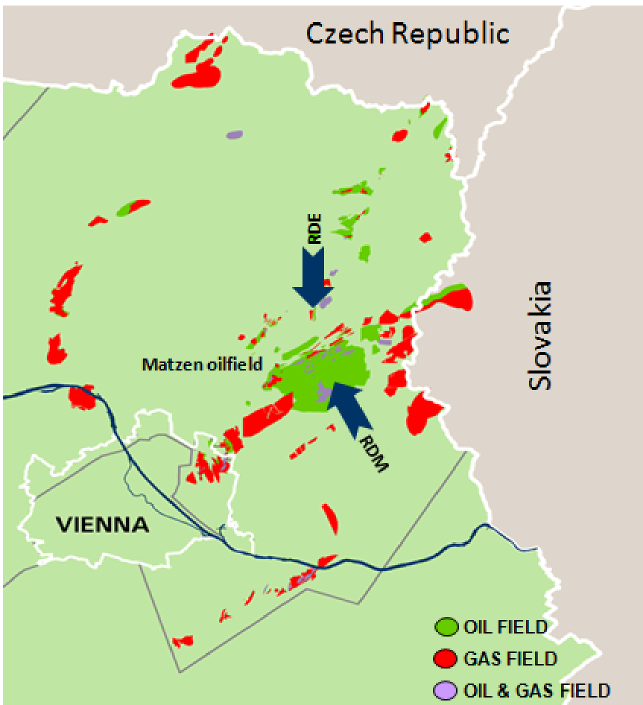

Figure 2: Field Location[1]

Generally, it can be said that the young ages of an oilfield are short and remain only up to five years. The following next five to ten years yield a plateau production phase followed by

[1] C.f. Ondracek et al. (2012), p. 6

a decline phase that persists about 30 to 100 years. In the last phase, a lot of effort has to put into maintenance to support the battle against declining production curve. If primary and secondary recovery methods (e.g. waterflooding) are applied, the reservoir will only be depleted up to about 1/3 of its original oil in place (OOIP). Hence, mature oilfields are those that are subjected to oil production over decades and associated with waterflood operations where about 2/3 of the OOIP is left behind. Mature oilfields contain a considerable amount of 'proved + probable' (2P) reserves. Of course, the profitability of mature fields is much lower compared to younger oilfields, but just because of that, there is an interest of re-development (rejuvenation) of mature oilfields to increase the production and profitability. The low oil price in the past was the main reason that hindered oil companies in re-developing mature fields, but this has changed in the last five years (effective April 2013).[2]

The further oil recovery is promoted, meaning from secondary to tertiary recovery methods, the more costs will accrue. Primary recovery methods are applied if sufficient reservoir pressure is available. This method includes the natural flow of fluids when oil is displaced by a water drive, the gas cap expands and when gas, that is initially dissolved in the oil, expands.

If the reservoir pressure declines due to the extraction of fluids, secondary recovery methods have to be applied. Therefore, artificial lift methods are used to increase the productivity of a well. Another method of secondary recovery is to inject water into the subsurface. Thereby, energy is added to the reservoir resulting in an increase in productivity.[3]

Tertiary recovery is the last stage of oil recovery. The methods used for this stage are thermal practices, gas injection and chemical flooding. Tertiary recovery mentioned in this thesis will refer only to chemical flooding (polymer flooding) due to the fact that a polymer pilot is in operation for the 8th TH.

The production profile of the Matzen Sand shows a rapid increase in oil production rate from the beginning of discovery in 1949. Production peaked in 1954 followed by a significant decrease of oil rate and a subsequent tail production until today. Since its discovery, 393 production wells were drilled in the Matzen Sand.[4]

The current (effective April 2013) number of producers in the Matzen Sand account for 69. In average, each well has a gross production of 109 m^3/d and an average oil production of 6,6 m^3/d. This results in an average water cut (WC) of 94%. There are currently 6 injectors with a total water injection rate of 4.500 m^3/d.[5]

Currently (effective March 2013) available surface facilities are two GOSPs each one in Auersthal and Matzen, one Water Treatment Plant (WTP) in Schönkirchen and one Gas Compression Station (GCS) in Auersthal. The pipeline network has an extent of ~2.000 km.

The Matzen Oilfield production is split into fields and areas and each of the areas again is split into individual horizons (reservoirs). The following fragmentation (Figure 3) shows a classification of OMV oilfields. There are two main fields (015 and 006) and these again are split into areas. Field 015 is split in Area 2 and 13 where Area 13 is Strasshof Tief and Area 2 is 'Matzen oilfield'. Field 006 is equal to Area 4 and it is mainly Erdpress with its individual horizons.

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[2] C.f. Ondracek, W.; Liebl, W. (2009), p. 1 et seqq.
[3] C.f. Engineering Insights (2013), p. 15
[4] C.f. Kienberger et al. (2006), p. 1 et seqq.
[5] C.f. Poldlehner et al. (2012), p. 14

OMV Austria is split into three concession areas, OMV NOe (Lower Austria), OMV OOe (Upper Austria) and OMV Wien (Vienna). This thesis comprises only the area of activities in Lower Austria.

The MORE programs' main focus areas are on the horizons with the biggest future potential regarding OMV Austria actual and future production.

The area covered by the re-development program is located about 30 km northeast of Vienna and extends over an area of approximately 220 km².

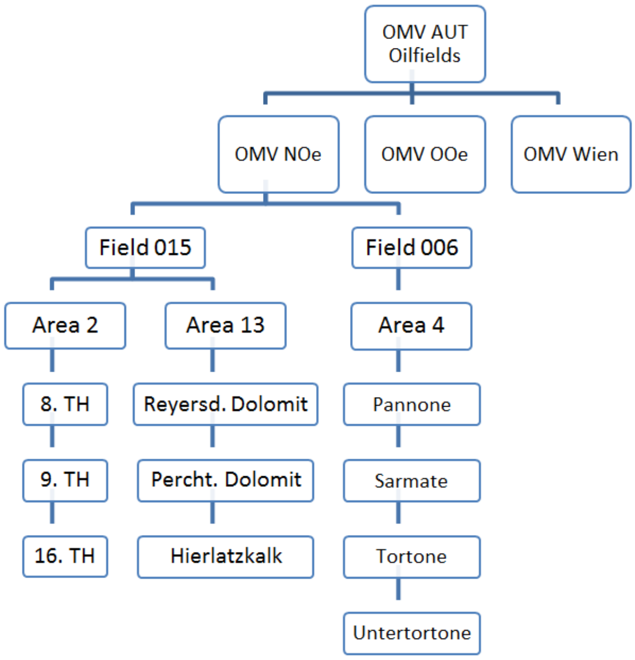

Figure 3: Classification of OMV oilfields[6]

2.2 Goals and Objectives of the MORE program

The MORE program specifically aspires to enhance the NPV. The increase of NPV is targeted by initiating and implementing new recovery strategies and technologies to accelerate production of 2P reserves, get access to 3P ('proved + probable + possible') reserves and as a consequence increment the ultimate recovery factor.

The Base Case forecasts a declining production rate due to limitations of well capacities and production handling capacities of surface facilities. Base Case, from a productional point of view predicts that production rate that will be achieved if no investments in facilities or new wells are implemented. Despite all that, ongoing workovers will be included for

[6] C.f. Geomedia Ltd – 8. TH (2012), p. 14

the Base Case. The cumulative production predicted by the Base Case equals the quantity of the currently (effective December 2010) booked 2P reserves.[7]

The goal of the MORE program is to accelerate production of the 2P reserves (proven + probable reserves) significantly. The program also contains the implementation of projects to realize 3P reserves within the next 30 years (effective April 2012):

- 10,33 MM m³ oil (65 MM bbl) 'proved + probable reserves'.
- 10,33 MM m³ oil (65 MM bbl) 'possible reserves'.[8]

The strategy is to drill 'in-field' producers to reduce the natural decline of the production rate of the mature horizons. To stabilize the production rate, the optimization of the production is an issue.

Another focus of the MORE program is to introduce secondary recovery methods, e.g. increase the gross production by increasing water flooding, and tertiary recovery methods, e.g. polymer flooding. The challenges to be met are:

- Rig contracting for drilling and workover
- Upgrade of the existing pipeline system and electrical grid
- Upgrade of existing surface facilities due to extra gross production and extra gas volumes
- Water management

The next figures show the development of oil rates (Figure 4) and water rates (Figure 5) per day for the Base Case (2P), Accelerated Case, Growth Case and Maximum Case:

Accelerated Case: An acceleration of the production of the 2P reserves is based on an investment of 260 MM EUR. That investment includes drilling of 80 new wells and adaptions and improvements of surface installations. It would be possible to stabilize oil production at a level of 2.300 m³/d (14.500 bbl/d) over the next 7 years (effective 2012) with that scenario. Key Performance Indicators (KPI) like RoR, NPV or the ratio of NPV over CAPEX, based on the assumptions of the accelerated case would deliver quite good results. Rate of Return (RoR) is estimated to be 59%, NPV is calculated with +100 MM EUR and the ratio NPV over CAPEX is determined by 0,4.[9]

Growth Case: The investment of that scenario means excess figure of 190 MM EUR compared to the Accelerated Case. The costs of 450 MM EUR contain adaptions and improvements for surface installations and pipeline system as well as drilling of further production and injection wells over the next 10 years. The goal of that case is the oil production of a quantity that equals the amount of 2P reserves and additionally the half of possible reserves. The total volume of oil produced for that scenario would be 16,69 MM m³ (105 MM bbl).[10]

Maximum Case: The investment of that case means additional costs of 420 MM EUR compared to the Growth Case. According to that the total costs of 870 MM EUR should be invested over the next 10 years to drill 225 new wells and to significantly improve surface facilities to handle much higher gross production rates. For the Maximum Case, the

[7] C.f. OMV Aktiengesellschaft (2012): Project Initiation Note, p. 3 et seqq.
[8] C.f. Production and Reserves MORE (2012), p. 2
[9] C.f. OMV Aktiengesellschaft (2012), p. 3
[10] C.f. OMV Aktiengesellschaft (2012), p. 3, 4

daily oil production would increase from 2.300 m³/d (14.500 bbl/d) to 3.500 m³/d (22.000 bbl/d).[10]

Mature field re-development does not only mean excellent implementation of production but also perfect control of cost and production, recognition of options to increase the value of mature fields and consequently improve the KPIs of activities.[11]

For both scenarios, Growth Case and Maximum Case, excellent KPIs are expected. RoRs of about 50% and the ratios of NPV over CAPEX are estimated to be 1. The NPV is determined to be 540 MM EUR for the Growth Case and 790 MM EUR for the Maximum Case.[12]

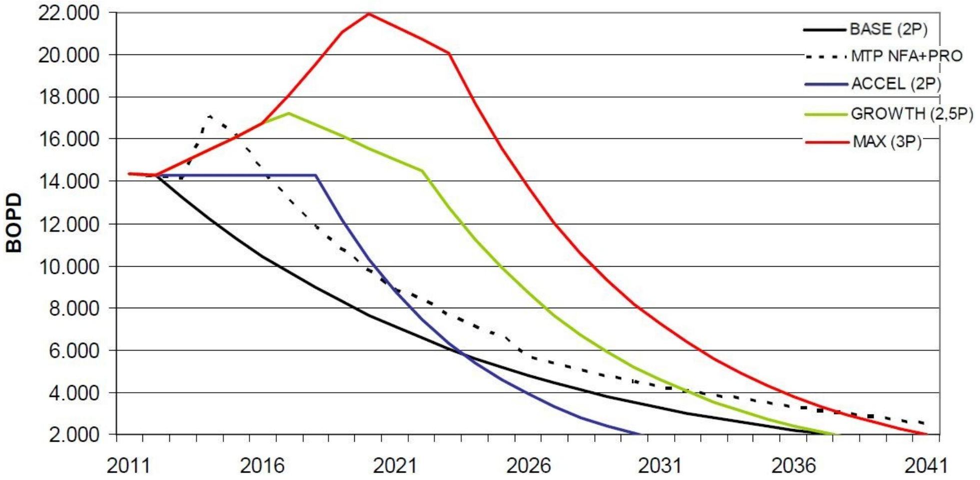

Figure 4: Oil production in the course of the MORE program[13]

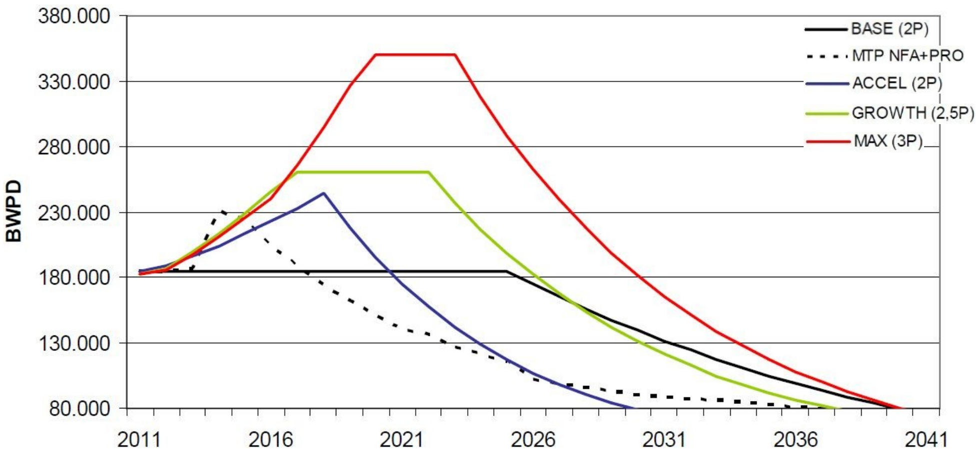

Figure 5: Water production in the course of the MORE program[13]

Several approaches are scheduled in the MORE program to increase the gross production rate:

- Recomplete existing wells

[11] C.f. Ondracek, W.; Liebl, W. (2010), p. 1

[12] C.f. OMV Aktiengesellschaft (2012): Project Initiation Note, p. 3 et seqq.

[13] C.f. OMV AUT E&P (2012), p. 10

- Locate and drill new (horizontal) wells
- Optimize artificial lift systems (e.g. exchange SRPs and install ESPs)
- Upgrade surface facilities (e.g. GOSP Matzen)

Other important aspects of the MORE program are to hold CAPEX & OPEX at the minimum. This should be managed by:

- Efficient use of facilities
- Efficient water management
- Efficient dealing with energy

To implement the MORE program multiple reasonable sub-projects should be planned. These individual sub-projects are geared towards re-development of particular reservoirs, horizons, areas or fields. MORE covers the three stated below projects (see Figure 2) until now (effective March 2013), where the projects from the 8th and the 16th TH are described by the re-development Matzen (RDM):

- Re-development 8. TH
- Re-development 16. TH
- Re-development Erdpress (RDE)

2.3 8th Tortonion Horizon

The re-development project 8th TH is part of the MORE program. It consists of four layers and is located between the village Schönkirchen-Reyersdorf and Gänserndorf. Start of OMV-production of that horizon was in 1951 and 339 wells were producing in total. Currently (effective May 2013), about 80 production wells are in operation and 8 wells inject water from the northern edge of the field. Three injection wells are situated within the field and act as pattern injection wells. The average oil production rate per well is 2,40 m³/d (15 bbl/d). The injection rate per well is in the range of about 320 – 480 m³/d of water (2.000 – 3.000 bbl/d of water).[14]

Two phases were defined by OMV Austria in the course of the re-development of that horizon. These phases represent the production levels:

- Phase 1 refers to a gross production of 4.200 m³/d.
- Phase 2 refers to a gross production of maximum 7.500 m³/d.

The re-development of the 8th TH focuses on an increase of the NPV. Project motive is an enhancement of the gross production rate with the limitation of 4.200 m³/d (phase 1). By exceeding that rate, additional adaptations of the surface facilities would be inescapable (phase 2). Surveys have shown that reserves are still in the reservoir. These reserves are accessible through an individual field re-development. Therefore, re-development concepts were elaborated and simulated.

[14] C.f. FDP – RD 8. TH-Phase 1 (2012), p. 6: after consultation with Günther Scherz; EATP-1 Project Management 1

2.3.1 Re-development contents 8th TH

Currently phase 1 is in execution and the selected concept for re-development of the 8th TH includes the below mentioned activities.[15]

Increase the oil production rate of 24 existing wells

This should be accomplished through successful implementation of the following opportunities. Several sub-surface activities have to be performed to recognize an increase of the oil production rate. One option is a bean-up operation where change in stroke speed of SRPs is implemented. Thereby, strokes can be accelerated by modifying the size of the sheaves. For this purpose, no workover or well intervention is necessary. Costs for such an operation are minor and can be performed with short lead time. Limiting factor can be an increased gross production and associated water handling problems.

11 workovers should be implemented between 2012 and 2014. The total oil rate of these 11 wells before the workovers start is 24,50 m^3/d (154 bbl/d). After implementation of workover, a rate of 57,20 m^3/d (360 bbl/d) should be reached, meaning an increase of 134%. Currently (effective January 2013) 7 workovers have already been performed.

For the purpose of perforating new additional horizons, a workover rig is necessary. In the context of the re-development project 8th TH a new layer in one well should be perforated and the production of the current producing layer is abandoned. In ten other wells, an additional interval should be perforated.

13 well interventions should be implemented between 2012 and 2014. The total oil rate of these 13 wells before the well interventions start is 28,60 m^3/d (180 bbl/d). After implementation of well interventions, a rate of 55,65 m^3/d (350 bbl/d) should be reached, meaning an increase of 93%. Currently (effective January 2013) no well interventions have been executed.

Pump change has to be performed if an old pump should be substituted by a new one. For that operation it is not necessary to change the surface equipment (pump jack or ESP surface installations). A pump has to be changed if it shows severe signs of wear and tear. The lead time for pump change operations is quite long due to the long order time of at least nine months.

Unit change is necessary if an old unit is replaced by a new and bigger one. Usually a unit change goes hand in hand with a pump change. However, no well intervention or workover is necessary if only the unit is changed.[16]

Drilling of 6 new production wells

These are all located to the village of Schönkirchen-Reyersdorf in close proximity to Gänserndorf. The most cost effective way for drilling the new wells is a cluster solution.

[15] After consultation with Günther Scherz; EATP-1 Project Management 1

[16] C.f. FDP – RD 8. TH-Phase 1 (2012), p. 26 et seqq.: after consultation with Günther Scherz; EATP-1 Project Management 1

Currently (effective January 2013) no drilling activities took place. The first well to be drilled is planned in February 2013.

2.4 16th Tortonion Horizon – Bockfließ Area

The 16th TH is just as the 8th TH a part of the Matzen oilfield and it is located about 20 km NE of Vienna. The production start was in 1949 and it covers an area of about 10,5 km².

In 2003 a geological survey was accomplished in order to implement a simulation study which should be the frame for a potential re-development project. Due to the complexity of the model, it was split into two sectors (sector I & sector II). These two sectors depict the present Bockfließ Area which is the main area for the re-development of the 16th TH.

In 2006 a main conclusion of the simulation study was performed. Although, production lasts since the 1950s, the result of the conclusion was that only half of the 3P reserves will be produced until 2046 if production is continued with the current steady rate. To accelerate and maximize the production and ultimate recovery factor, a 'Produce the Limit' (PtL) workshop was implemented in 2011 and according to the results of that workshop the re-development project 16th TH Bockfließ Area was started.

Currently 69 production wells and 5 injection wells are in operation in the Bockfließ Area. The average gross production rate per well is 118 m³/d and the average oil production rate results in 6 m³/d.

Oil production is assisted by 64 sucker rod pumps and 5 electric submersible pumps. The total gross production in that area amounts to 7.500 m³/d and total oil production results in 452 m³/d, giving a water cut of 94%.[17]

2.4.1 Re-development concepts for 16th TH

For the design of the re-development of the 16th TH several concept were elaborated just as for the 8th TH. In the following, the considerations about the concepts are shown:

Earliest oil – Min CAPEX

The strategy of that concept is "quick win and low budget" activities. Hence, no additional drilling activities are planned because drilling new wells would significantly increase CAPEX. The concept only includes PtL activities:

- 17 bean ups
- 8 unit changes
- 5 pump changes
- 6 artificial lift changes

[17] C.f. Geomedia Ltd – 16. TH (2012), p. 14

- 30 workovers that all include new perforations

By means of this concept, the ultimate recovery factor can be improved from 58.3% to 58.9%. This amounts an additional oil of approximately 60 MM m³ (~375 MM bbl) over the life cycle of the field.

To implement that concept several adaptions for surface installations have to be done. These adaptions would include the replacements of flowlines and trunklines for 'life oil metering stations' (LOEMST) and 'life oil collecting stations' (LOESST). GOSP Auersthal would need additional processing installations for the implementation of that concept. To provide an appropriate injection system, two new pumps for the injection ring would be indispensable and modifications for the injection water pipelines would be necessary.[17] [18]

Max oil rate

The strategy of that concept is based on PtL activities and drilling of new producers and injectors:

- Drill 6 new horizontal ESP wells with a rate per well and day of about 2.000 m³
- Drill 2 new horizontal injectors with a rate per well and day of about 3.000 m³
- Adaptions of 5 pumps for already existing injectors to perform a rate per well and day of about 1.000 m³
- 30 workovers that all include new perforations

By means of this concept, the ultimate recovery factor can be improved from 58.3% to 62.3%. This amounts an additional oil of approximately 397 MM m³ (~2.500 MM bbl) over the life cycle of the field.

To implement that concept several adaptions for surface installations have to be done. These adaptions would include the replacements of flowlines and trunklines for LOEMSTs and LOESSTs. GOSP Auersthal would need additional processing installations like slug catchers and modifications to the existing headers and water regulation system have to be performed. In addition, water treatment tanks have to be extended. As in the case before, two pumps for the injection ring to inject the treated water have to be adapted and the pipeline system for the injection water needs to be extended. The newly drilled injection wells have to be tied into the water injection system[19] [20]

Max recovery

The strategy of that concept is based on PtL activities and drilling of new producers and injectors:

- Drill 6 new horizontal ESP wells with a rate per well and day of about 2.000 m³
- Drill 2 new horizontal injectors with a rate per well and day of about 3.000 m³
- 30 workovers all including new perforations that should be performed in three-years-steps. Each step consists of 10 workovers starting in 2017

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[18] C.f. Wanzenböck, G. (2012), p. 17 et seqq.
[19] C.f. Geomedia Ltd – 16. TH (2012), p. 15 et seqq.
[20] C.f. Wanzenböck, G. (2012), p. 22 et seqq.

By means of this concept, the ultimate recovery factor can be improved from 58.3% to 62.9%. This amounts an additional oil of approximately 461 MM m³ (~2.900 MM bbl) over the life cycle of the field.

To implement that concept several adaptions for surface installations have to be done. These adaptions would include, as in the cases before, the replacements of flowlines and trunklines for LOEMSTs and LOESSTs and additional processing installations for GOSP Auersthal. The water treatment tanks have to be extended and two injection ring pumps have to be adapted. The pipeline system for the injection water needs to be extended and the newly drilled injection wells have to be integrated into the water flooding system[19 20]

Restart

The strategy of that concept is based on PtL activities and drilling of new producers and injectors:

- Drill 6 new horizontal ESP wells with a rate per well and day of about 2.000 m³
- Drill 8 new inclined ESP wells with a rate per well and day of about 1.000 m³
- Drill 4 new horizontal injectors with a rate per well and day of about 3.000 m³

By means of this concept, the ultimate recovery factor can be improved from 58.3% to 62.3%. This amounts an additional oil of approximately 397 MM m³ (~2.500 MM bbl) over the life cycle of the field.

To implement that concept several adaptions for surface installations have to be done. These adaptions would include two adaptions of pumps for the injection ring to re-inject the treated water. The replacement of flowlines and trunklines for LOEMSTs and LOESSTs will be indispensable and additional processing installations for GOSP Auersthal will be necessary. The water treatment tanks for the additional water have to be extended. The pipeline system for the injection water needs to be extended and the newly drilled injection wells have to be integrated into the water flooding system.[21 22]

2.5 Erdpress

Erdpress is a satellite field and it is part of the Hohenruppersdorf field located about 20 km in the north of Gänserndorf. Other fields in that area are Niedersulz and Spannberg.

The field Hohenruppersdorf started its production in 1939. In the late nineties the satellite field Hohenruppersdorf OST was developed. Other field developments followed in 2001 and 2002. These developments and Erdpress 1 in 2003 were the results of an exploration project.

Results from two appraisal wells were the basis of three extra producers drilled in 2005. After a new simulation study new wells were planned and drilled from February to August 2011.

[21] C.f. Geomedia Ltd – 16. TH (2012), p. 17 et seqq.
[22] C.f. Wanzenböck, G. (2012), p. 31 et seqq.

In June 2011 a workshop was held to determine future development options and improvements for existing wells. Based on that workshop, two scenarios have been elaborated:

- 'Drilling, Recompletion and Water Injection' Scenario
- 'To the Max' Scenario

Each scenario is split into four divisions – base case, base case optimized, new wells and water injection. 'Base Case' can be equaled to a 'do nothing case'. In the 'optimized base case', additional gains are expected by recompletion. The case 'new wells' review the potential for extra production of oil if new wells are drilled. 'Water injection' was taken into consideration for maintaining the pressure and as a consequence to improve the recovery factor.[23]

[23] C.f. Redevelopment Erdpress – Preliminary FDP (2011), p. 38 et seqq.

3 Cost accounting in the oil and gas industry

Cost accounting is done voluntarily and due to economically reasons. In contrast to accounting, there are no legal regulations. The main reason of cost accounting is to provide the basis of decision making.[24]

The preparation and processing of source data for cost accounting is based on certain criteria like accrual of costs and split of costs. In particular, there are three steps of cost accounting:

- Cost-type accounting
- Cost-center accounting
- Cost-unit accounting

Cost-type accounting shows the origin and the basement of total cost accounting. This means that the results of cost-type accounting are adopted in cost-center accounting and in cost-unit accounting. Therefore it is important to proceed very accurate and carefully for further accounting. The data for cost-type accounting are gathered from upstream areas of the corporate accounting system like financial, material, personnel and assets accounting. The target of cost-type accounting is to scientifically acquire and account actual costs, accrued within a period. It is not about a specific calculation but rather basically about the recognition of costs. Thus, cost-type accounting provides information about which costs and the amount that accrue in a period.[25]

Cost-center accounting is the second stage of cost accounting. In that stage, the costs determined from cost-type accounting are distributed to the corporate areas of activity (cost center). This is particularly applied for overheads that cannot be allocated to individual cost units.[26] One target of cost-center accounting is to allocate primary overheads (e.g. personnel costs, lease costs). An important task is the allocation of internal costs (e.g. payment of the in-house service station). Another issue of cost-center accounting is the determination of charge rates for further charging of overheads from cost centers to cost units (products).[27]

Cost-unit accounting is the last stage of cost accounting. After cost acquiring by means of cost-type accounting and further charging to cost centers within cost-center accounting, follows cost attribution to individual cost objects.[28] Therefore, the central question arise, for what are costs arisen in an accounting period. A cost object is defined as performance unit and product unit leading to an internal consumption of goods and thereby causing costs.[29]

[24] C.f. Reschny, R.: Einführung in die Kostenrechnung. U
[25] C.f. Fandel, G. et al. (2004), p. 83
[26] C.f. Atilgan, E. (2001), p. 9
[27] C.f. Kalenberg, F. (2004), p. 70
[28] C.f. Kühnapfel, A. (2003), p. 8
[29] C.f. Preißler, P.; Dörrie, U. (2004), p. 105

3.1 Goals of cost accounting

The main target of accounting is to create clarity and transparency as well as financial information about the business entity.

Various internal and external parties of a corporation require financial information about a company:

- Information for managers that help for decision-finding of operations
- Information for investors that are essential to find out how to invest reasonable
- Information for partner to ensure the integrity of the business based on contractual regulations
- Information for finance authorities to ensure that the corporation pays the appropriate amount of taxes[30]

There are basically four main costs to be distinguished for accounting purposes in the oil and gas industry:

- **Acquisition costs** are costs that incur for obtaining an asset (field, area, property, reservoir). Costs for rights for exploring, drilling and producing oil are classed among acquisition costs.
- **Exploration costs** incur during the exploration phase of an asset. Expenditures for exploration include costs for examination of certain areas that are potential candidates for carrying oil. Common costs that are involved are G&G costs and costs for exploration wells.
- **Development costs** are costs that incur to get access to proven reserves (see explanation in Appendix A). Furthermore, costs for preparing surface facilities like pump jacks, processing installations and storage tanks belong to development costs.
- **Production costs** are costs that incur in the process to extract the oil from the subsurface and lift it to the surface. Further costs for gathering, treating and storing the oil belong also to production costs.[31]

For accounting the four main types of costs (mentioned above) in the oil industry, companies can decide whether to apply the successful efforts (SE) method or full cost (FC) accounting. The aspect thereby is whether to capitalize or expense the incurred costs.

The **SE method** enables a company to capitalize those costs that are related with successful discovering of oil and gas reserves. Costs accruing through a discovery operation that is not successful are charged against the revenues of the corresponding period.[32]

Figure 6 shows an overview of the four main types of costs and how they are treated under the SE method. By considering the acquisition costs, they are capitalized as unproved property until either proved reserves are found or until the property is impaired/abandoned (see figure). In the successful case of finding reserves, the unproved property is then reclassified to a proved property. For accounting purposes, exploration costs are separated in drilling costs and nondrilling costs. If the costs are nondrilling costs,

[30] C.f. Wright, C. J.; Gallun, R. A. (2005), p. 21
[31] C.f. Gallun, R., et al., (2001), p. 31
[32] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 235

they are charged to the income statement (expensed as incurred). In the case of drilling costs, exploration costs are capitalized for the duration that the well is in progress until it is determined if proved reserves are found or not. If an exploration well was successful (discovering proved reserves), exploration drilling costs are then added to wells and related equipment and are amortized on the basis of production. In the case of drilling a dry hole, costs are expensed.

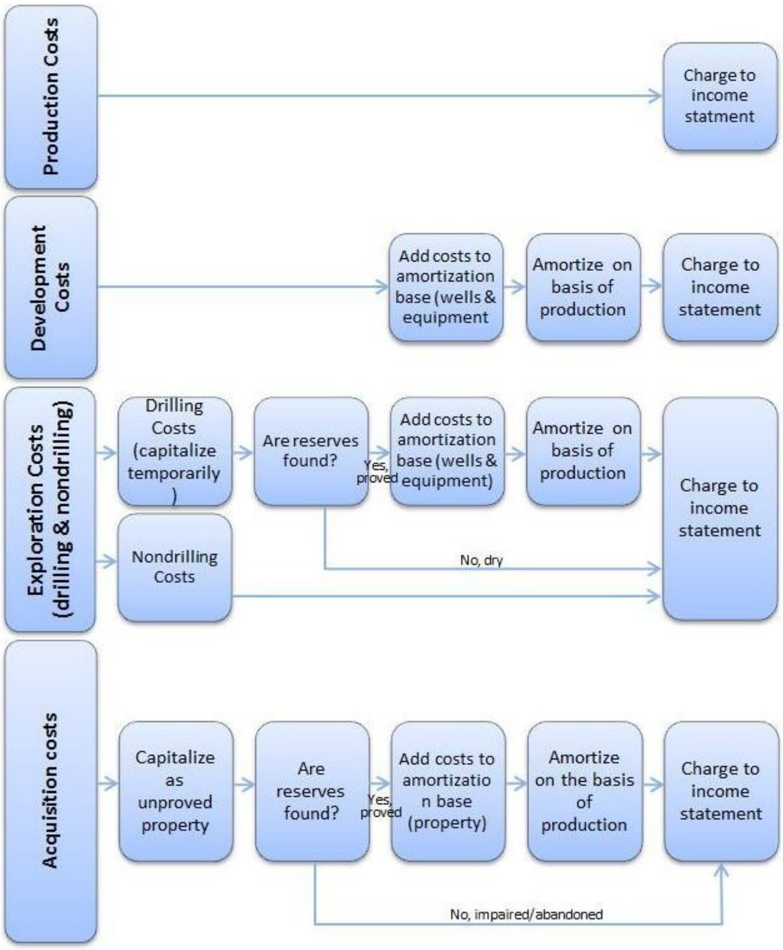

Figure 6: Successful Effort Method[33]

Development costs include the costs for drilling development wells. They are capitalized irrespective of whether or not finding proved reserves. Considering the production phase, all costs incurred in that phase are expensed.

Full cost accounting makes no distinction between discovering reserves or not. As can be seen in Figure 7, acquisition, exploration, and development costs are capitalized under the FC method. As with the SE method, acquisition costs are estimated as an unproved property. If proved reserves are found, the unproved property is transferred to a proved property. If no proved reserves are found (property is impaired or abandoned), the costs stay capitalized and are then transferred to abandoned or impaired costs. Using the FC method, all

[33] C.f. Gallun, R., et al., (2001), p. 43

acquisition, exploration, and development costs incurred in each country are capitalized (see Figure 7). Compared to these costs, production costs are expensed as incurred.

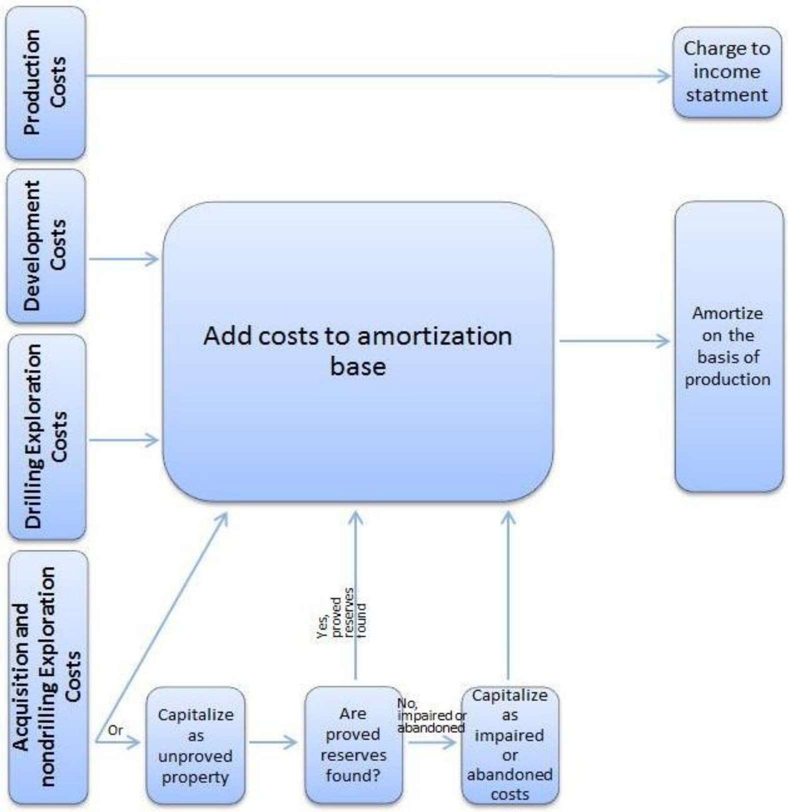

Figure 7: Full Cost Accounting[34]

3.2 Capital Expenditures

Capital expenditures are onetime costs and accrue usually at the beginning of a project. At the most, they arise several years before any incomes are made. CAPEX are classed with:

- Geological and geophysical costs (G&G)
- Drilling costs
- Completion costs
- Process equipment
- Storage tanks
- Wellhead
- Lines to transport the oil
- Buildings for supply and accommodation for the staff, etc.

[34] C.f. Gallun, R., et al., (2001), p. 54

Potentially, capital expenditures also emerge during the economic life of projects, buildings, facilities etc. These CAPEX have to be differentiated from the ongoing operating costs. Later arising capital expenditures can arise in case of:

- The natural flow is not intense enough to bring the oil autonomously to the surface. As a consequence, artificial lift systems have to be installed that again induces high capital expenditures. These expenditures must not be seen as belonging to operating expenditures.
- If the methods of artificial lift systems are not sufficient anymore, other measures have to be adopted to lift the fluid. For this purpose, there is the opportunity of secondary recovery, meaning waterflooding, or tertiary recovery, meaning injection of chemicals.
- Reconstruction and upgrading of already existing buildings and facilities[35] [36]

ISO 15663-2 defines CAPEX and OPEX as follows:

Table 1: Exemplary differentiation of CAPEX and OPEX[37]

CAPEX	OPEX
Project management	Operation man-hours
Engineering personnel	Maintenance man-hours
Contractor project support	Maintenance spares and materials
Asset purchase cost	Tools and equipment
Fabrication follow-up cost	Scheduled overhaul
Initial spares	Sub-contractors's manpower
Tools and test equipment	Transport of personnel
Documentation	Transport of consumables
Installation	Fuel/oil
Commissioning manpower	Energy consumption costs
Commissioning consumables	Chemicals
Materials	Onshore support in offshore operations
Initial training	Rental/lease payments
Reinvestment cost, for equipment of expected lifetime shorter than installation/function lifetime	Insurance

[35] C.f. Mian (2011), p. 154 et seqq.
[36] C.f. Wright, C. J.; Gallun, R. A. (2005), p. 66
[37] C.f. ISO 15663-2 (2001), p. 23

3.3 Operating Expenditures

Costs that are aggregated due to the day-to-day business and therefore frequently occurring are called operating expenditures. OPEX should be seen as costs for facilities that have an expected useful life shorter than one year. Operating costs are mirror inverted compared to capital costs, because the latter are onetime occurring costs.

Operating costs include:

- Labor costs that contain salaries and benefits of employees
- Materials and services in the day-to-day business (e.g. equipment, tools etc.)
- Storing, processing and measuring of the oil
- Costs for evacuation accrue for the transport of oil from the field
- Maintenance (e.g. workover and well interventions)
- Insurance costs arise especially at the beginning of the lifetime of the field
- Main and field office costs, technical services, lease of equipment, public relation[38]

3.3.1 Production Costs

Production costs are referred to as costs to lift the oil to the surface as well as costs for gathering, treating and storing.

"Production costs are those costs incurred to operate and maintain an enterprise's wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities (par. 26) and other costs of operating and maintaining those wells and related equipment and facilities."[39]

Production costs are part of the costs of produced oil. For that reason, these costs are inventoried as finished products until the oil is sold. From the sales point on, production costs are costs of goods sold. For most practical purposes, production costs are expensed as incurred immediately after production. Usually the oil is sold after production. But there are companies having oil in their stock. In most cases this is only a small proportion compared with the total production. Due to the small quantities in the storage tanks, oil companies do not assess their stock in the financial statement.

Cost centers are used to cluster production costs. Such cost centers can be reservoirs, individual areas or fields. The smaller a cost center is, the more transparent and clearer the accounting. Production costs can be either directly attributable to a specific well, lease, area or field or have to be allocated on a reasonable basis. If a worker operates on a specific well or if an individual well is repaired and maintained, the accruing costs for it are attributed to the appropriate well as long as the allocation of costs happens on basis of individual wells. Costs for water flooding, serving several wells have to be allocated on reasonable basis. Conventional allocation bases are e.g. quantities of produced oil or amount of production wells.

[38] C.f. Gallun, R., et al., (2001), p. 261
[39] Statement of Financial Accounting Standards (1977), p. 10

Table 2: Direct attributable costs & allocable costs - examples[40]

Direct attributable costs	Allocable costs
Equipment, working fund and fuel that can be assigned to a specific well, lease, area or field	Offices and facilities (e.g. water treatment plants, tank farms, etc.) that operate for several wells, leases, areas or fluids
Workers that act only on one well or record working time for several wells	Wages and benefits of workers that operate several wells (e.g. supervisors of more than one lease)
Costs for service companies (e.g. fracturing, acidizing, etc.)	Depreciation of facilities that act for several leases (e.g. water treatment plant, etc.)
Maintenance for an individual well	Costs for transportation for the purpose of several wells
Insurance and property taxes	Costs for disposal systems if several leases are afflicted
Production taxes for individual wells, leases, areas or fields	Costs for boats and fuels in offshore operations when several leases are involved

Labor costs: To operate and maintain wells and consequently a whole field, supervisors, field operators and employees are required which in turn cause costs like wages, salaries and employee benefits. The activities of first-level supervisors is directly associated with the work of employees in the field. Hence, the accruing costs can directly be charged to the appropriate well or lease. For that course of events, accurate time recording is of importance. If time recording is not available, the costs for hours worked have to be allocated on reasonable basis.

Maintenance: These activities include common repairs, workovers and re-completions. Common repairs incur at buildings, facilities, crop damage, tanks and flowlines etc. Maintenance operations are expensed except where the operating life of an asset is essentially extended or the productivity of the wells is substantially increased. The allocation should hint which well or lease is involved, then costs for maintenance operations can be directly allocated to the appropriate well or lease.[40]

Workovers: Production costs also include several types of workovers. For the purpose of workover a special rig is used to restore or boost production from a certain, already producing well. An example, where a workover is unavoidable is an open hole completion where co-producing sand would partially or completely clog a part of the production tubing. Another example for workovers is if the perforations of a casing are clogged by small rock fragmentations or sand and prevent fluid flow into the production string. For both cases, workover costs are expensed as production costs because production of an existing horizon was solely restored.[40]

This definition is not valid for OMV Austria because all costs for workovers are capitalized and therefore do not belong to production costs, aligned with OMV E&P and Ernst & Young procedure.[41]

[40] C.f. Gallun, R., et al., (2001), p. 264
[41] After consultation with Kammlander Bernd; EFAT-C Controlling

Workover operations where new proven reserves are developed belong to drilling operations, either exploration or development drilling. An example for such an operation is plugging back and complete at a shallower depth to produce the shallower hydrocarbons. Another example would be drilling a well to 3.000 m and completing it in 2.000 m. In a subsequent workover operation, a dual completion is set in 3.000 m depth. Both cases lead to a capitalization because it deals with new production from new formations and not with restoring production of already existing developed formations.

Costs for fuels, working funds and materials: If materials and working funds are used in common maintenance activities, costs accrue. They are counted as production costs and can be assigned to individual wells or leases.[42]

Property Taxes: Another component of production costs are property taxes and insurances on proved reserves/properties. A property tax is an ad valorem tax whereas the difference to specific taxes is that the ad valorem tax is on the price of the considered good and not on the quantity. They are levied on behalf of governmental interests. Property taxes on proved properties cause an essential proportion of production costs whereas property taxes on unproved reserves only cause a negligible part of costs. They are then resembled as exploration costs rather than production costs. Types of **insurances** range from general liability, indemnity and remuneration to fire and other accidents. Property taxes and insurances can be assigned to individual properties.[42]

Overheads: These costs, e.g. administrative costs, not directly associated with oil production are expensed as incurred. Administrative costs include costs for head office as well as costs for labor acting in the head office, legal fees, accounting etc. Overheads that are not directly related to oil production do not count among production costs and are therefore not allocated to individual wells or leases for reporting purposes.[42]

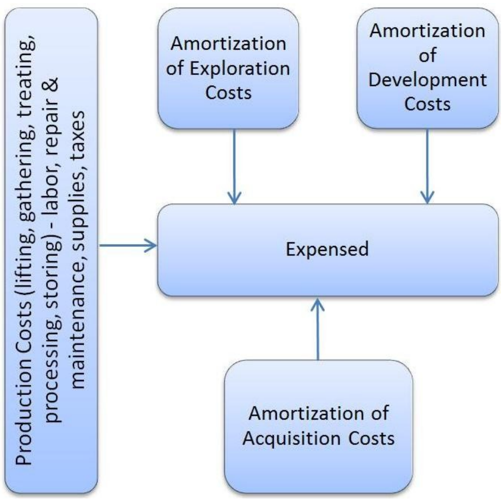

Figure 8: Accounting for production costs[43]

Figure 8 shows a schematic of accounting for production costs. The definition is for both accounting methods (SE & FC) the same. Production costs become part of the cost of the oil and gas produced.

[42] C.f. Gallun, R., et al., (2001), p. 266 et seqq.
[43] C.f. Gallun, R., et al., (2001), p. 161 et seqq.

Costs for secondary & tertiary recovery

Facilities are required that bring along high expenditures to perform 2nd & 3rd recovery methods. Costs like drilling new horizontal injection wells or acquisition of injection equipment can arise. These costs accrue during the operating phase of a project but has to be treated as costs for the development of a field. Therefore, they are capitalized and then amortized over the "unit-of-production" method (see chapter 3.3.2).

Tertiary recovery methods include among others injection of chemicals. There are two options for accounting chemicals to be injected:

- Chemicals are assumed to be injection well equipment and can be therefore depreciated. In this case costs for chemicals are then amortized together with injection wells and associated equipment.
- Costs for chemicals can be assigned directly to production costs.

Costs for Maintenance activities of secondary and tertiary recovery systems are expensed and hence part of production costs.[44]

Costs for gathering systems

A gathering system is a network of pipelines and treatment installations which transport the oil to certain central points. It consists of various installations like pumps, headers, separators, tanks, compressors, that sort of thing. After the oil is treated in the gathering system (removal of sediments, gas and water), it is then pumped for further treatments into processing plants. The separated water is moved to the water treatment plant and the associated gas to a compressor station.

Accumulated costs for the construction of a gathering system belong to development costs. Consequently, these costs are part of DD&A. Costs incurred during the operation of a gathering system are counted among production costs and are therefore expensed.[44]

Costs for water disposal system

The high portion of produced water especially in mature oilfields is an undesired by-product that has to be re-injected by means of injection wells. This has to be performed in an environmentally friendly way and to maintain the natural reservoir pressure. The components of a water disposal system have to be established in a way to ensure the treatment of the water and removal of chemicals and corrosive materials. After processing, the water can be re-injected into the underground. Costs for building a water disposal system belong to development costs and are on the subject of DD&A. Operating costs are expensed as incurred and should be allocated if the system serves multiple leases.[44]

If the production wells produce almost the same quantity of water, costs can be allocated based on the number of wells. If the wells produce considerable different quantities of water, costs should be allocated based on the amount of water produced (see example in 3.2 Cost allocation).

Costs for tubular goods

In the oil and gas industry tubular goods are defined as casing and tubing. Costs for tubular goods consist of the acquisition and installation and are capitalized for initially well construction. Following substitution or repair activities of tubular goods are assumed to be production costs and therefore expensed.[44]

3.3.2 Lifting Costs

Performance indicators based on total lifting costs are used to detect how efficient an oil company produces oil from a field. The applied formula for that approach is as follows:

$$Lifting\ costs\ \left[\frac{EUR}{bbl}\right], \left[\frac{EUR}{boe}\right] = \frac{Total\ lifting\ costs\ per\ year}{Total\ oil/gas\ production\ per\ year}$$

Formula 1: Lifting costs[44]

To interpret and analyze the result of that formula correctly it is important to understand the costs that hide therein. In various literatures lifting costs and production costs are summarized as one term. The Financial Accounting Standards Board FASB defines production costs in paragraph 24 as follows:

"Production costs are those costs incurred to operate and maintain an enterprise's wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities (paragraph 26) and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- *Costs* of *labor to operate the wells and related equipment and facilities.*
- *Maintenance.*
- Materials*, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities.*
- *Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.*
- *Severance taxes."*[45]

Another important paragraph of FASB is no. 25 and also consists of lifting costs:

"*Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs also become part of the cost of oil and gas produced along with production (lifting) costs identified in paragraph 24.*"[46]

Depreciation, Depletion & Amortization (DD&A)

The terms of tangible property and intangible property are used in financial accounting. Tangible properties are *depreciated*, intangible properties are *amortized* and natural resources

[44] C.f. Gallun, R., et al., (2001), p. 268, 269, 619
[45] Statement of Financial Accounting Standards (1977), p. 10
[46] C.f. Gallun, R., et al., (2001), p. 619 et seqq.

are *depleted*. For oil and gas accounting, the total term depreciation, depletion and amortization (DD&A) is used.

This means for SE companies like OMV is that acquisition costs and costs for wells, associated equipment and facilities are amortized to become element of costs for oil produced. Thereby, proved reserves and proved developed reserves have to be distinguished:

- Acquisition costs have to be amortized over proved reserves.
- Wells, associated equipment and facilities have to be amortized over proved developed reserves.

Acquisition costs are defined as costs clustered in the interests of the whole cost center. That's why all reserves are involved that are produced from these cost center.

Proved reserves represent:

- Reserves that can be produced from already existing completed wells.
- Reserves that will be produced in future through drilling new wells.

Proved developed reserves are reserves already produced from existing wells and equipment. Wells, associated equipment and facilities have to be amortized over proved developed reserves because based on these reserves costs already accumulated for completed wells and equipment. Remaining proved undeveloped reserves are excluded to amortize existing wells because these reserves can only be produced if extra future expenditures are incurred. If a reservoir is completely developed, proved reserves and proved developed reserves are equal.

To ensure the accumulation of costs an appropriate cost center is required. For this purpose reservoirs, areas or field are ideal.

For amortization of acquisition costs and wells, associated equipment and facilities, the so-called 'unit-of-production method' is used.[47] [48]:

$$\frac{Book\ value\ at\ year\ end}{Estimated\ reserves\ at\ beginning\ of\ the\ year} \times Production$$

Formula 2: Unit-of-production method[49]

If all costs, meaning costs plus DD&A and royalties, are present in total lifting costs per year, the result of the above mentioned formula is a criterion of the overall operating performance. By analyzing of an individual field, DD&A and royalties should be ignored. It always depends for which area performance indicators are evaluated.

For benchmarking there are several influences to pay attention on. E.g. oil can be produced at a lower price than gas. Company A produces mainly oil and company B mainly gas. From all appearances using the afore-noted ratio for benchmarking, company A produces less efficient than company B. Therefore it is important to keep an eye on the selection of companies to be benchmarked. Furthermore there has to be a distinction between onshore

[47] C.f. Gallun, R., et al., (2001), p. 161
[48] C.f. Statement of Financial Accounting Standards (1977), p. 11 et seqq.
[49] C.f. Gallun, R., et al., (2001), p. 161, 263

and offshore production. Even if an onshore production is cheaper than an offshore production it does not necessarily mean that the onshore produced oil yields more profit than the offshore produced oil. The reason therefore is that offshore production is more high-grade than onshore production and can therefore be sold at a higher price.

3.4 Life Cycle Costing

Over the course of re-development projects, a lot of investments have to be done to meet the requirements of these projects. For selection of several investment options, it is often not easy to choose the economical best alternative. Thereby, the method of life-cycle-costing (LCC) provides a tool that enables to pick out the best option from a variety.

In the past, acquisition costs were the main criterion for the selection of equipment. This is the easiest way to choose between different alternatives but it can lead to poor long-run costs. Low acquisition costs often go hand in hand with low reliability, meaning higher maintenance costs, and higher energy consumption, resulting in an increase of costs during operation. To make reasonable financial decisions it is important to have accurate details of costs over the life cycle of the equipment.[50]

Seen from a historical perspective, LCC has its origin in the 1960s. At that time, the U.S. Department of Defense recognized at first that acquisition decisions based only on the procurement price could lead to bad long-term costs. Following studies has shown that total costs of ownership (TCO), such as costs to operate and maintain the system, are typically higher than initially investment costs.[51] [52]

3.4.1 Definitions of LCC

The purchaser pays that price for equipment that the manufacturer has to defray. These are costs accruing for manufacturing plus a proportion of profit. Due to that fact, the life cycle costs of the customer perspective will always be the highest.[53]

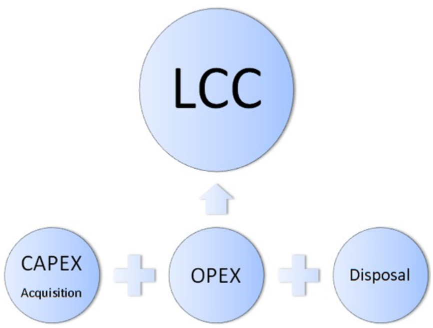

Figure 9: Encountered costs during LCC

[50] C.f. Barringer, P. (1997), p. 3
[51] C.f. Eisenberger; Lorden (1977), p. 102
[52] C.f. Gluch; Baumann (2004), p. 571
[53] C.f. Emblemsvag (2003), p. 17

LCC involves not only acquisition costs but also costs for the operating time frame and costs for disposal. That fact results from the issue that LCC considers a certain time frame. A huge amount of costs can be allocated to maintenance and support activities. LCC is a type of investment decision tool to compare different investment alternatives. Despite a specific life cycle, LCC does not include all environmental costs and cannot be used as an environmental accounting tool. The main uses and purposes are listed below:

- LCC can be used as a decision support to compare between different alternatives and decide for the most cost effective one.
- Unlike in traditional cost accounting tools, the method of LCC enables a meaningful insight how individual pools of costs are composed of.
- LCC is a tool to manage ecological problems.

There are different point of views that has to be considered, depending on the perspective of interest:

- Marketing perspective
    - Introduction → Growth → Maturity → Decline
- Production perspective
    - Conception → Design → Development → Production → Logistics
- Customer perspective
    - Purchase → Operating → Support → Maintenance → Disposal[54]

LCC within this thesis will only focus on the customer perspective due to the fact that OMV is purchaser of oilfield equipment.

LCC is defined as a process to collect, interpret and analyze data and apply tools and techniques to forecast future supplies that will be necessary in individual life cycle stages of a system of interest.[55] By means of life cycle costing it is possible to choose between alternatives covering all costs that accrue throughout the life of an asset, starting from investment costs followed by operating and maintenance costs and finally ending with abandonment costs.[56]

3.4.2 The life cycle of equipment

The life cycle is defined by "*all development stages of an item of equipment or function, from when the study commences up to and including disposal*".[57]

The life cycle of equipment consists of individual stages that a component or several components of a system run through, negligent which decision makers are involved. According to which equipment should be treated, each stage of the life cycle can be extended by several detailed activities.

A manufacturer will typically grapple with the first stages of the cycle against what a customer has to concern with the right-hand side of the graphic, shown in Figure 10.

[54] C.f. Okechukwu (2011), p. 22
[55] C.f. North Atlantic Treaty Organisation (2009)
[56] C.f. Al-Hajj, Vorarat (2004), p. 1
[57] ISO 15663-1 (2000), p. 3

There are intensified laws and regulations, handling the lower part of the graphic and the left-hand side due to increasing ecological problems since the 1950s. A lot of companies realized that new opportunities can be yield through that laws and regulations and already grapple with the lower part and the left-hand side of the graphic.

Considering the de-manufacture part in Figure 10, there are several options for end-of life strategies for equipment. The first alternative is whether to return the equipment or not. Some companies are obligated to take back their own equipment because of laws and regulations. Other companies take back the equipment because they recognize creation of value. The last option is that a company takes back the equipment that is neither the producer nor the customer of it and disposes the equipment of. The numbered arrows in Figure 10 indicate the following:

1. Direct recycling or re-use
2. Remanufacture of reusable components
3. Reprocessing of recycled material
4. Raw material regeneration

After the equipment has reached its life-end, it can be either re-used or de-manufactured. Re-usage is the best option considering costs and environment. The farther the equipment is situated towards the left-hand side of Figure 10, the more it is downgraded. Being on the other side, the better it is to sell. This means in other words, the equipment has to be demanufactured for the purpose of economically interest.

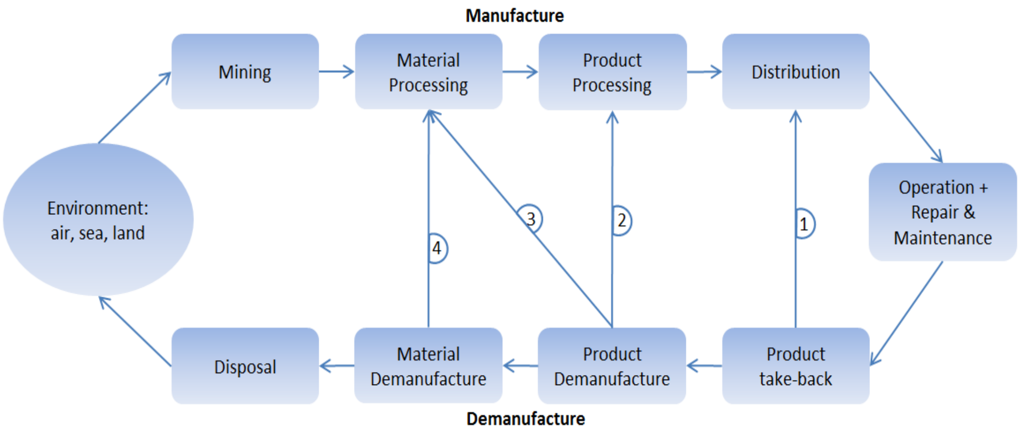

Figure 10: Life Cycle after Emblemsvag[58]

3.4.3 Advantages and disadvantages of LCC

There are various advantages and disadvantages of life cycle costing. The method is defined as the sum of initially acquisition costs plus subsequently operational costs considered over

[58] C.f. Emblemsvag (2003), p. 18, 20

the entire life cycle of the equipment. The consequent goal should be to minimize total costs over the observed timeframe.[59]

One advantage of LCC is that it provides a management tool to compare particular alternatives and serves as a selective tool for the most economical alternative. Another advantage of life cycle costing is that it can be applied as an evaluating tool by trading off initially acquisition costs against subsequently operational costs. A further advantage is yield by a view into costs and the composition of particular pools of costs.

Fortunately, the disadvantages inferior to the advantages of life cycle costing. But there are two disadvantages that should be kept in mind. One disadvantage is yield by an initially thought too long timeframe. This happens especially when older technologies are substituted by newer ones. Another disadvantage of LCC is that it is difficult to develop a meaningful model to predict operational costs over a certain timeframe. The reason therefore is that suitable data are often not available.

3.4.4 LCC in the oil and gas industry

The Norwegian Petroleum Industry developed Norosok standards to unify LCC techniques for selecting the equipment that gives the best economical values. Norsok standards are widely referenced to international standards.

Life cycle costing for the petroleum and natural gas industry is also defined by ISO 15663. In part 1, life-cycle cost is defined as "*discounted cumulative total of all costs incurred by a specified function or item of equipment over its life cycle*[60]. The acquisition costs of equipment compared to its total costs of ownership (OPEX & disposal costs) over the total time frame of interest is only the tip of the iceberg. This can often be in the range of up to 75% of total life-cycle costs of the system.[61] Considering an electric submersible pump, the energy costs to operate the pump are sharply higher than the acquisition costs. In other words, pumps have to be purchased by casting an eye at the energy efficiency of the pump to save money over the life time of the pump.[62]

Life cycle costing can be used very spacious. It can be applied to all phases (conceptual, planning, constructing and operating phase) that a facility or equipment passes through. In the long-term history of the oil and gas industry, the feasibility of projects was bound to beat down the CAPEX to a minimum. OPEX played only minor walks-ons for pushing projects through. The circumstance to beat down the CAPEX to a minimum led often to operational costs that rocketed upwards. The method of LCC offers therefore a tool to get the knack of the problem. Due to increasing aging oil fields, maintenance is brought into focus of the industry. That again means that OPEX are more emphasized because maintenance costs belong to operational costs.

LCC in the oilfield can be used for optimization purposes of existing facilities and optimization for the operation phase. The cost elements that should be included are capital and

[59] C.f. Remer (1977), p. 61
[60] ISO 15663-1 (2000), p. 3
[61] C.f. Kayrbekova, D. (2011), p. 3
[62] C.f. Barringer, P. (1997), p. 5

operational costs as well as costs for deferred production.[63] A distinction between CAPEX and OPEX is shown in chapter 3.2.

The complicacies in applying LCC are to acquire or generate data and the uncertainty of future predictions due to the incertitude of discount rate, lifetime and prediction of future operational costs like costs for energy or labor costs.[64] A database for failure that can be used to calculate how often a component or facility needs to be repaired is provided by *OREDA®*.

LCC Model after ISO 15663

ISO 15663-2 defines four stages with its individual sub-categories for a LCC Model. Figure 11 shows an overview of the steps[65].

The numbering in Figure 11 is not up against with the consecutive numbering. It only provides assistance for describing the development of a LCC model.

1.1 Identify goals: The goals should be elaborated with all stakeholders, all team members and above all with the responsible managers. Therefore, two question arise that have to be answered:

What are we looking at? That questioning shows the focus which system or equipment should be examined.

Why are we looking at it? That question justifies the examination.

1.2 Identify constraints: ISO 15663-2 schedules three sources that might lead to constraints:

Project constraints: Such constraints might arise due to time scale constraints. E.g. Change the fixed specification during construction and hook-up. Therefore, a response in a few days will be required and the LCC has to be adapted to the time scale. For this purpose a possible response can be either that the change has little or significant impact.

Technical constraints: E.g. There is a change on an existing facility and several new technologies are available. This means that the operator may be constrained to certain technical options.

Budgetary constraints: E.g. Limitations on CAPEX

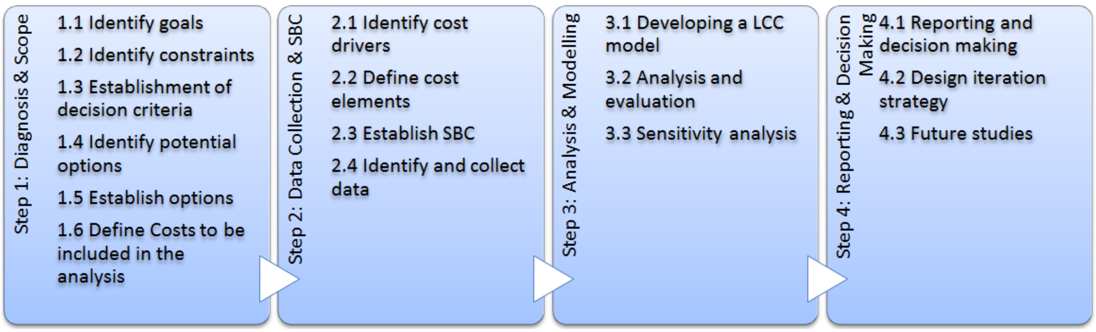

Figure 11: Process of life cycle costing after ISO 15663-2

[63] C.f. Norsok Standard (1996), p. 5
[64] C.f. Al-Hajj, Vorarat (2004), p. 1
[65] C.f. ISO 15663-2 (2001), p. 2 et seqq.

1.3 Establishment of decision criteria: The picked decision criterion should always be adapted to the final user. It should constitute a structured approach for defining the economic influence on technical decisions. The most common evaluation methods are:

NPV: The net present value is the present value of future cash flows that are associated with an investment by deducting initially investment costs.[66] The method of NPV is an economic procedure for projects, taking into account costs, time and discount factor.[67]

The NPV is calculated by discounting the net cash flows, summing them over the timeframe of the project and deducting the initial investment.

$$NPV = -I_0 + \sum_{t=1}^{n} \frac{NCF}{(1+i)^t}$$

Formula 3: Calculation of NPV

Where

I_0	is the initial investment;
NCF	is the net cash flow at the end of year t;
t	is the amount of years;
i	is the discount rate;
n	is the considered timeframe in years.

A positive result of the formula above means that the sum of the discounted net cash flows is higher than the initial investment. In other words, the project gives a positive return on investment and it can be accepted. If the NPV is negative, it is better to reject the project.

Life cycle cost: The method of life cycle cost can be applied for ranking alternatives. Life cycle cost is defined as the discounted sum of CAPEX, OPEX, revenue impact and decommissioning.

CAPEX are all costs that arise initially. This are costs such as discovery, appraisal, engineering, construction and commissioning.

OPEX are all costs to sustain the operation and to maintain the asset. A juxtaposition of CAPEX and OPEX is shown in chapter 3.2.

Revenue impact describes the costs when the revenue stream is affected. This can happen when production is deferred due to a planned shutdown and an unscheduled shutdown (failure). Other examples for revenue impacts are penalties and tax credit/debit.

Decommissioning are costs for abandonment. Therefore costs for the project management, survey costs, transportation, equipment etc. arise.

Internal rate of return (IRR): The method of IRR enables for an investment with fluctuating revenues to calculate an average, annual income return. For this method, that rate of interest is desired where the NPV of a project is zero.

[66] C.f. Adams (2010), p. 2
[67] C.f. Barringer, P. (1997), p. 4

This is the rate that puts the PV of the net cash flow on a level with the initial investment costs:

$$I_0 = \sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t}$$

Formula 4: Calculation of IRR

Where

I_0	is the initial investment;
NCF	is the net cash flow at the end of year t;
t	is the amount of years;
n	is the considered timeframe in years.

The IRR can be used as a decision tool. If IRR is higher than the discount rate, the project can be accepted because it gives a higher return on investment than the required minimum. The project should be rejected if IRR is less than the discount rate.

Profitability index (PI): It is defined as the ratio of the present value of future cash flows and the initial investment.

$$PI = \frac{PV}{I_0}$$

Formula 5: Calculation of PI

If PI is higher than 1, the project can be accepted because it gives a positive return on investment. A project should be rejected if PI is less than 1.

Payback Method: The payback period is calculated to determine the number of years required to recover the initial investment from the future cash flows of the project.

$$Payback\ period = \frac{Initial\ investment}{Annual\ cash\ receipts}$$

Formula 6: Calculation of the payback period

Break-even: The break-even point is defined where the NPV is 0 or where revenues and costs balance. It is applied e.g. for the determination of the sales volume required to generate a positive revenue.

$$Break-even\ volume = \frac{Initial\ investment}{Price\ per\ unit - OPEX\ per\ unit\ produced}$$

Formula 7: Calculation of the break-even volume

1.4 Identify potential options: Therefore, an interdisciplinary team should be used to find out the options to be reviewed. All the alternatives should be structured and reported. The quality can be increased by use of a moderator.

1.5 Establish options: The alternatives identified in the previous section should be screened. Each option should be screened by the same procedure/questions:

- What are the costs?
- Can it meet the technical tasks?
- Is it practical?
- Can it meet the HSSE criteria?

1.6 Define costs to be included in the analysis: A total analysis of the total system will be necessary to define all the costs involved. Costs for energy, processing and maintenance will be an issue in this section.

2.1 Identify cost drivers: The cost drivers are dependent on the application, the type of equipment and the configuration of the equipment. The major cost drivers will be found within CAPEX and OPEX.

2.2 Define cost elements: The identified cost drivers in the previous section have to be calculated. This section deals with, how the costs are calculated in the model.

2.3 Establish structured breakdown of costs: The cost elements should be structured taking into account the way in which costs are acquired and the way cost elements are calculated.

2.4 Identify and collect data: It can be seen from the previous section, which kind of data will be necessary to calculate the individual costs defined in section *2.2*. Reasonable data can be gathered from operators, contractors and vendors. Data for CAPEX can be costs for man hours, equipment, material or re-investment. Data for OPEX can be costs for man hours, spare parts, energy, maintenance or processing.

3.1 Developing a LCC model: A calculation sheet should show the most economical results for modeling life-cycle costs. Ideally, the sheet should be flexible and adaptable to add further types of costs. It should be transparent to the user and accurate to show the differences between the alternatives. The calculation should include discounted future costs and revenues back to the present value.

$$PV = \frac{FV}{(1+i)^t}$$

Formula 8: Calculation of the present value

3.2 Analysis and evaluation: The key is to keep LCC as simple as possible. An analysis should focus on

- Design differences
- Impact on the economics
- Identifying the cost drivers
- Sensitivity of the results towards the input data

Analysis should be done to find out differences of alternatives and check out why they occur, if they are logical and can be explained.

3.3 Sensitivity analysis: It targets to provide the basis for reducing the number of options and improve confidence in those options. Then it can be decided whether to implement an option or evaluate further options.

4.1 Reporting and decision making: The LCC model and results should be contained in the final project documentation. The results should be spelled out with supporting arguments.

4.2 Design iteration strategy: The next LCC iterations should be mentioned and identified. An example could be to identify the next step of system selection. This could be system optimization with material optimization.

4.3 Future studies: If step *4.2* is not necessary, studies for the next phase should be made. This can be e.g. the integration into other systems or maintenance strategy.

3.5 OMV Upstream accounting

For activities in producing oil & gas, OMV utilizes for accounting and reporting purposes the successful efforts method. This method is described at the beginning of chapter 3.1. In compliance with the SE-method, those upstream costs are capitalized (CAPEX) that lead directly to discovering, acquiring and developing the oil fields. Costs that do not directly lead to discovering, acquiring and developing the oil reserves are entered as expensed (OPEX).[68]

For production purposes it is often not clear whether workovers, well interventions or any maintenance activities have to be entered as assets or liabilities. Hence, the terms of production, operative expenditures and accounting for activities after production start are illustrated hereafter.

Production starts after successful exploration and development when hydrocarbons are extracted from an oil or gas field; i.e. after ending the development of at least one part of the proven reserves of a field. Operating expenditures is a synonym of production costs. They are ongoing costs of the operation and maintenance as well as associated equipment of an oil and gas field and have to be expensed as incurred. Typical production costs are:

- Labor costs that are associated with production
- Costs for slight repairs of wells and other production equipment
- Gathering the oil from several wells in the field/area
- Transportation and storing the oil
- Treating the oil through separation of water, gas and sediments
- Costs for activities to guarantee future production (water injection etc.)
- Costs for reservoir simulation to optimize production
- Consumption of feedstock, supplies and fuels

[68] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 235

- Costs for insurance that are associated with the field[69] [70]

Production costs comprise the costs up to the time when the production well cannot produce hydrocarbons anymore due to economic or technical reasons. Then the well has to be abandoned and brought in a safe condition. All other costs that accrue subsequently are abandonment costs and do not belong to operative costs.

During the production phase, oil reserves are designated as production assets. If an asset is not under full usage, it can be designated as production asset under construction.

The SE-method sets only minor rules for activities after the production start. The reason is that these activities often overlap. Maintenance can coincide with improvement and upgrade, workover can coincide with development. For that reason OMV specified some regulations for minor and major repairs, workovers and upgrading activities. The following principles have to be applied[71]:

- The new installed parts have to be capitalized and the substituted parts have to be derecognized in case of enhancement or replacement of older parts of a plant.
- Activities that target to increase the production rate through incremental production or generate developed proved reserves from previously undeveloped proved reserves lead to capitalization.
- Finding proven reserves are exploration and appraisal activities. All costs that are directly related of drilling exploration and appraisal wells have to be capitalized. If these wells were not successful, these costs have to be gathered as expenses (either appraisal or exploration) in the income statement.
- The SE-method provides for development activities (i.e. create developed proven reserves from undeveloped proven reserves) widely capitalization.

Maintenance

Minor repair, maintenance and replacement of small parts have to be expensed as incurred. Costs for **well interventions** that do not fall into the predefined workover activities have to be expensed immediately. The capitalization of new inserted parts in the context of well intervention is also possible, if the older replaced parts are derecognized at the same time.

There are separate regulations for major repair, maintenance and replacement activities. Capitalization of costs for improvement and upgrade activities cause in general de-recognition of the replaced parts. The problem thereby is that the book value is often not available. In that case, estimates are necessary. If only a few information are available, it is reasonable due to cost-benefit considerations to expense the costs for the particular activities whereby no de-recognition for the replaced parts is necessary.

Workover

Workover is defined as broad and constant rehabilitation work to restore, maintain or improve production of a completed well by re-entering the well. Workovers are all activities

[69] C.f. Gallun, R., et al., (2001), p. 261 et seqq.
[70] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 246
[71] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 247 et seqq.

that were not performed during the first completion of a well but subsequently and these activities do not depict well interventions.

The list below shows an overview of workovers. These activities have to be **capitalized** if successful. Therefore, costs for workovers **do not become part of production costs**. Components have to be derecognized if they are replaced by new one during workovers. Pumps, sand screens, packers, tubings, liners, sucker rods and X-mass trees belong to these parts.

- Re-perforation
- Installation of an injection well to change a producer to an injector
- Sand control to prevent sand migration from the reservoir into the wellbore
- Zonal isolation to avoid an unwanted influx of reservoir water/gas into the well-bore
- Testing the production of a well during and after workover to evaluate the potential of the well dependent on workover activities
- Re-completion to repair the original completion and restore the productivity of the well
- Well integrity to restore and improve the integrity of the casing
- Stimulation is mainly done by hydraulic fracturing and matrix treatments
- Data acquisition to gather information about the wellbore or formations[72]

Replacement of facilities

According to the general regulations of OMV accounting manual, subsequent costs of an asset have to be capitalized if the recognition criteria (future benefit, reliable valuation) are accomplished. To avoid double acquisition, derecognition of replaced parts of an asset is necessary. Replaced parts are components or objects that are tangible substituted by new components or objects.

If only parts of an object are replaced, the exact book value is not available. In that case, estimates are necessary, considering all possible factors like inflation, age etc.

Surveys for producing fields

Reservoir surveys that are performed to determine the potential of production increase or enable perforation into new formations with proved undeveloped reserves have to be capitalized. Costs for technical surveys, that can be allocated directly to drilling of wells or the preparation of facilities, are treated as a part of the costs of these assets. If the survey is not successful, the costs therefore have to be amortized.

[72] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 247 et seqq.

Exploration, appraisal and development activities after start of production

Even after commencement of production in a reservoir, activities like exploration of new reserves, development of proven reserves and activities to increase production can be adopted or continued.

If proven reserves are exploited or should be produced through activities, costs should be capitalized as development costs (e.g. drilling a service well).

If the activities are targeted to obtain proven reserves, costs should be treated as exploration and appraisal costs as explained before. The treatment of well costs depends on the result of the activity, whereas other exploration costs have to be expensed.

Certain activities can be of exploration and development nature at the same time, e.g.:

- Drilling into known producing horizons (development) and continuing drilling into deeper unknown horizons.
- Drilling into unknown horizons (exploration) and thereby coming upon hydrocarbons before reaching the desired horizon; if the desired horizon shows no hydrocarbons in place, the well has to be plugged back to the shallower horizon with hydrocarbons.

Cost allocations for exploration and development costs have to be done on reasonable basis. In the case of a plugged portion of a well, additional costs for the plugged part have to be expensed.

Secondary & tertiary oil recovery methods

After primary recovery (i.e. production that is due to the initial natural reservoir pressure and production with artificial lift systems) secondary and tertiary recovery methods must be applied. Thereby, the declining reservoir pressure is increased again by means of gas, water or chemical injection. Costs for injection wells and associated facilities have to be considered to the field development costs and capitalized in the corresponding well or facility categories.

The increase of proved developed reserves due to 2nd and 3rd recovery methods is allowed only after such techniques have been proved by tests. Capitalized costs of facilities for 2nd and 3rd oil recovery have to be depreciated on basis of total proved and developed reserves of the field.[73]

3.6 OMV cost accounting

The goal of cost accounting is to generate transparency regarding to the amount and responsibility of incurring expenses and performances. Cost accounting is the foundation of cost management, planning and economic analysis.

Cost accounting is used to calculate the costs per unit (e.g.: processing costs of oil in €/ton). If the management does not know the processing costs of oil or water treatment costs, they will not be able to determine the OPEX (EUR/m^3).

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[73] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 247 et seqq.

Cost accounting in OMV has to describe three different sections[74]:

- Production
- Underground Gas Storage
- Service

The depiction is done with Profit Centers (PC). For this Master Thesis, only the area 'Production' is of importance:

- Incomes are allocated corresponding to the produced amounts of oil and gas to the specific production areas (there are different areas for asset gas and asset oil).
- Costs emerge autonomous in the areas of production (e.g. labor costs, depreciation of facilities).
- Beyond that, costs from other areas of accountability are allocated to the areas of production according to the 'principle of causation'. In other words, costs are outlined at the causer and not at the location of origin of costs (e.g. maintenance costs are outlined at the recipient of goods and services, not at the area of maintenance).
- Only that costs are allocated to the production areas where identifiable goods and services underlie. Costs that are not allocated remain at the section 'Service'.
- Production areas are split into asset oil and asset gas.

A cost center is defined by several accounts. This are accounts for salaries, wages, trainings, cars, business trips, infrastructures etc. Costs are attributed to the aforementioned accounts and cost centers. Each cost center is matched to a profit center. The difference between cost center and profit center is that incomes are only charged to profit centers. This means that profit centers consists not only of costs but also of accounts of proceeds (oil, gas, natural gas liquids).

The elements of cost accounting are 'cost structure' (type of costs, cost center, profit center), 'cost allocation' (order, offsetting, shares in the costs) and 'cost aggregation' (projects, functional budgets). The implementation is done with SAP.

3.6.1 Cost accounting elements

OMV applies several cost accounting elements to describe cost structuring, cost allocation and cost aggregation:

- Elements for cost structuring: cost types, cost centers and profit centers
- Elements for cost allocation: orders and apportionment
- Elements for cost aggregation: projects and functional budgets

[74] C.f. OMV Austria Exploration & Production (2008), p. 7

Cost structuring

To create transparency in cost accounting, the accruing costs have to be structured regarding to their type of costs and location of where they arise (cost center, profit center).

A profit center is an organizational subarea possessing certain independence. A separate net profit or loss for the period is determined to assess and control profit orientated activities of the subareas. Thereby the subarea managers act in a fashion like independent enterpriser. The purpose of a profit center is the positive motivation of the subarea managers due to the profit orientated subdivisions.

Figure 12 shows the areas of OMV E&P Austria and appropriate profit centers. Level 1 shows the level of OMV Austria – income statement. The next subordinate level indicates the level of OMV Austria – production costs (level 2). The lowest level 3 shows the level of production costs per production area. Asset Oil has four production areas (1, 2, 4, 5) and Asset Gas presents six production areas (area 2-7). The following description is based on the profit center and cost center hierarchy of SAP. To understand the following profit centers and cost centers it is helpful to use the structure in SAP or view the structure in the Appendix B.

Production areas and gas storage (see Figure 12, level 3) are key elements of cost accounting in OMV Austria. These areas show costs and incomes for oil and gas production as well as costs and incomes for gas storage. Look into a cost center report in SAP, production costs are split into a general administration and staff management division and a productive division. The generation of cost centers in OMV is usually based on areal given conditions. Productive division – cost centers are first split into oil and gas and its individual areas. Each area has then two nodes – "general production" and "facilities and wells". In chapter 4.2 some of these cost centers are described exemplarily. Examples for cost centers of individual production areas are:

- Production wells
- Injection wells
- Gas lift supply
- Gas and Oil Separation Plants
- Gathering systems
- Pipelines

In the profit center 'Area Support (Area 0)' several costs that are related to oil & gas production are bundled. These costs cannot be allocated to a specific production are a hundred per cent. As a rule it is about costs for achievements that are performed for multiple production areas. Consequently, costs from that area are allocated or charged to specific production areas. Examples for cost centers of Area 0 are:

- Waste management
- Processing of associated gas and lift gas
- Tank farm
- Water flooding

The profit center 'Energy Park' bundles all energy creating cost centers of OMV Austria. Costs for energy generation are bundled in a profit center and can be obtained without further evaluation via a profit center report. For analysis purposes it is important to distinguish between external sourced energy and internal produced energy. Examples for cost centers of the Energy Park are:

- Current supply
- Heat supply
- Treatment of industrial water
- Gas conversion into electricity
- Power-heat-coupling

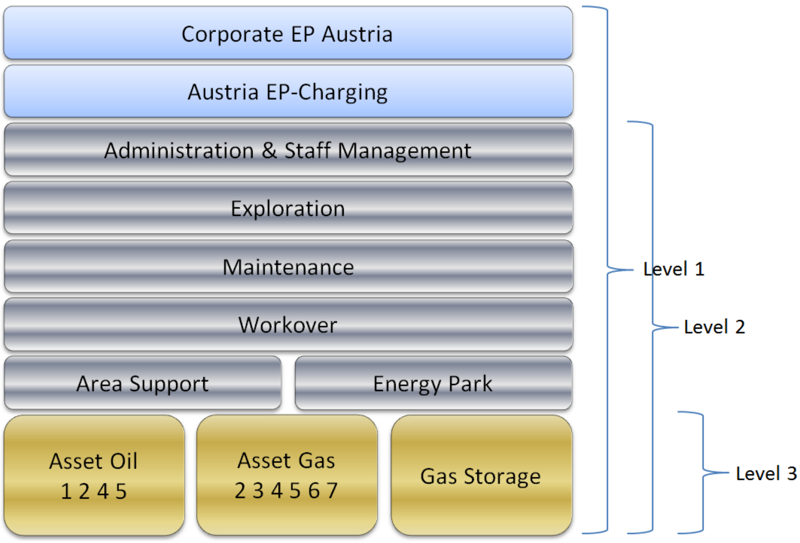

Figure 12: Areas of OMV E&P Austria[75]

The area service contains both, 'Workover' and 'Maintenance'. Structuring of these two divisions is usually done based on organizational aspects. 'Maintenance' contains of cost center nodes like:

- Workshops
- Logistic departments
- Electrical engineering
- Company fire brigade

The division 'Workover' is comprised of:

- Perforation and wireline service
- Drilling technique
- Transport

[75] C.f. OMV Austria Exploration & Production (2008), p. 10

- Pump service
- Pipe and rod warehouse

The profit center 'Exploration' is composed of expenditures for exploration activities as long as allocable to OMV Austria. In particular it is about expenditures for unsuccessful exploration wells (non-production costs). Successful exploration wells are capitalized according to the appropriate asset. Exploration is split into two sections in OMV Austria – 'Austria EP Exploration' and 'Deep Gas Austria Exploration' (since 2011).

The profit center 'Administration & Staff Management' consists of several cost centers:

- Administration: This node includes the cost centers for 'administration' and 'planning' to depict the performances of administration & staff management. Another cost center within that node is that of 'dispatched personnel'. The latter includes all labor costs for dispatched personnel whose payroll accounting is made by OMV Austria.
- Environment, authorities, safety: It includes costs for HSEQ and image projects of OMV Austria.
- Commercial: This node includes costs for property taxes and authorities.
- Finance: It includes costs for 'purchasing', 'controlling' and the 'administration of the finance department'. A sub-node of Finance is 'buildings & infrastructure'. It includes costs for facility management, office blocks and educational center. Another sub-node of Finance is 'materials management/warehouse'. It involves costs for warehouses (gas station) and materials management.
- Project Management: This node involves costs for projects, surveying & geo-information, engineering, documentation, telecommunications system and process control systems.

In Figure 13 a rough cost structure of OMV Austria is shown. It can be seen that there are four main sectors. These are 'group charges corporate' (Konzernumlagen Corporate), 'EP Austria Production Costs', 'EP Austria Non Production Costs' and 'blocked cost centers' (gesperrte Kostenstellen).

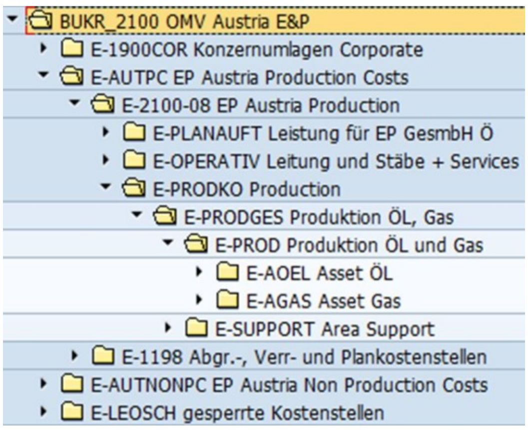

Figure 13: OMV Austria cost split – asset oil and gas[76]

[76] N.B. OMV SAP Structure

Considering EP Austria Production costs, it is evident that there is again a split in Production Oil, Gas and Area Support.[77]

Figure 13 shows a further split into individual areas of Asset Oil. Thereof, the split of Asset Oil can be seen into the individual areas (Area1 Öl, Area2 Öl, Area4 Öl, Area5 Öl Aderklaa). Each of the areas can be split into a last level of 'oil production general' (Öl Produktion allgemein) and 'plants and wells' (Stationen und Sonden). In a last level, the individual cost centers are shown. In the example of Figure 13, cost centers of 'oil production general' can be seen.

In SAP of OMV it is possible to have insight of a profit center view and cost center view. In the profit center view it is possible to break down costs to individual areas. Areas provide the lowest level of the profit center view. Watching a cost center report, it is feasible to break down further (see Figure 14). A total cost structure of OMV Austria E&P can be seen in the Appendix C.

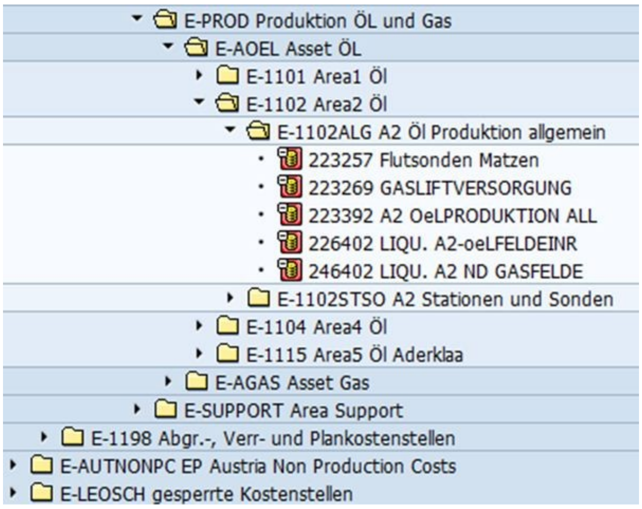

Figure 14: OMV Austria cost split – lowest level

Cost allocation

The goal of cost allocation in OMV Austria is the disclosure of costs according to the costs-by-cause principle.[78] This principle means that only those factors of production can be apportioned to a cost object that are utilized for producing these quantities of units. In other words, the costs-by-cause principle only apportions costs to an object if these costs are attributable to the object. This means an accurate disclosure of production costs of the 'production areas' (and 'UGS') and a financial disclosure of the 'service area' (maintenance, workover, exploration and administration & staff management).

Fundamentals of cost allocation: In general, cost allocation only makes a sense if it serves the purposes of cost accounting (correct disclosure of operating results of 'production areas', 'UGS' and 'service').

[77] N.B. OMV SAP Structure

[78] C.f. OMV Austria Exploration & Production (2008), p. 20

Cost allocation of performances is basically done via orders. The advantage is that the recipient of goods and services can see allocations of defined job accounting cost types (transparency for the recipient) and the provider of goods and services can identify the costs of the individual performances (transparency for the provider).

Allocation from cost center to cost center without interposition of orders should be avoided due to the reason of transparency and are only used in defined cases.

Cost allocation via orders has to be configured that the same received performance is depicted in the same way for each recipient of goods and services, namely as job accounting cost type.

In terms of cost accounting, orders are "roadsters" to gather and allocate further costs and revenues. Orders are split into sales based orders and **internal orders**. Sales based orders mainly conduce controlling of sales achievements (e.g. allocation of revenues from the production areas). For cost accounting in OMV Austria, **internal orders** are essential. Internal orders serve the allocation of costs between organizational units of OMV Austria and especially cost allocation according to the costs-by-cause principle (e.g. orders for maintenance).[79]

Primary costs (e.g. material and external service) as well as internal services of all areas are gathered in internal orders and then allocated to the recipient of performance.

A particularity of cost accounting in OMV Austria is the technique of job accounting. Costs that are gathered in orders are accounted for three cost types – internal services, external services, material:

- External services: These are services that are entered to an order and then allocated to the recipient. This is neither a concern of primary external services nor of external services allocated from cost centers.
- Internal services (OMV): These are internal services from cost centers that are allocated to orders and then allocated further to the recipient. Material overheads are also contained therein.
- Material: This is material that is entered to the order and allocated further to the recipient.

Example: OMV performed a well intervention in December 2010 for an oil well in Bockfließ. Thereby a change of the electric submersible pump and a change of the tubing string were performed. By entering the order number for that operation in SAP it can be visualized the portions of external services, internal services and material:

- Total Costs EUR 53.459,42
  - External services EUR 20.092,51
  - Internal services EUR 23.700,00
  - Material EUR 9.666,91

It is summarized to say that for the main part, services from cost centers are allocated to orders especially internal services resp. external services that are entered to cost centers.

[79] C.f. OMV Austria Exploration & Production (2009), p. 21

Another case of application is the internal allocation of energy. This is made via allocation between energy producing and energy consuming cost centers on the basis of accruing.

Besides internal orders there are other types of cost allocations. These are **cost dispersion** and **cost-element-percentage** method.

Dispersion is used to disperse according to the amount the following types of expenditures - automobile insurances, automobile taxes, rents and labor costs that cannot be embraced directly on an individual cost center. Dispersions are charged via sender cost centers and allocated through deposited distribution coefficient to individual recipients. Dispersions are mainly used for the purpose of streamlining to minimize the acquisition effort of accounting transactions.

Costs for the material management and warehouse (material overheads) are allocated via cost-element-percentage. The basis is to assign the material to orders or cost centers.

Illustration: The costs of OMV Austria Exploration & Production GmbH – Department Controlling in Gänserndorf accounted for €20,000 for the month of January 2013. The production office in Gänserndorf has monitored the wells shown in the tables below.

The example shown in the Tables 3, 4 and 5 does not relate to real data. These values are rough estimates that were assessed during this Master Thesis. Moreover, the result of that calculation should not be used for analysis purposes. The calculation should indicate how cost allocation can be done.

Table 3: Example OMV Austria: Cost allocation

Lease	Number of wells	m³ of oil produced (January)
8. Tortonion Horizon	80	4.770
16. Tortonion Horizon	69	3.180
Erdpress	13	795
Strasshof Tief Oil	40	2.385
Total	**202**	**11.130**

If the costs of the office are split according to the number of wells, the following allocation of costs results:

Table 4: Cost allocation based on the number of wells

Lease	Calculation	Costs
8. Tortonion Horizon	€20.000 x 80 wells / 202 wells)	€7.921
16. Tortonion Horizon	€20.000 x 69 wells / 202 wells)	€6.832
Erdpress	€20.000 x 13 wells / 202 wells)	€1.287
Strasshof Tief Oil	€20.000 x 40 wells / 202 wells)	€3.960
Total		**€20.000**

If the costs of the office are split according to the m³ of oil produced, the following allocation of costs results:

Table 5: Cost allocation based on the m³ of oil produced

Lease	Calculation	Costs
8. Tortonion Horizon	€20.000 x 4.770 m³ / 11.130 m³)	€8.571
16. Tortonion Horizon	€20.000 x 3.180 m³ / 11.130 m³)	€5.714
Erdpress	€20.000 x 795 m³ / 11.130 m³)	€1.429
Strasshof Tief Oil	€20.000 x 2.385 m³ / 11.130 m³)	€4.286
Total		**€20.000**

Another example is the water treatment plant in Schönkirchen. It handles not only the produced water of the Matzen oilfield, but also the water produced of the field in Erdpress, Pirawarth and Hochleiten. Therefore costs must be apportioned to all areas that utilize the services of the water treatment plant.

4 Investigation of OMV Austria E&P Costs

In the first level it has to be distinguished between oil and gas. Each of both divisions is split into areas and for each of the areas SAP provides a profit center report (see chapter 3.6).Taking a closer look into a profit center report in SAP, the terms of lifting costs and production costs are of importance. Lifting costs are the sum of all costs incurred during the production process and are generally defined as production costs + royalties + DD&A. Royalties consist of field tax and production tax. DD&A consists of depreciation of intangible assets and tangible assets.

Production costs are one level below the lifting costs. They are in general defined as the sum of OPEX + pipeline tariff + insurance. Insurance consists of property insurance of the enterprise and insurance for vehicle.

4.1 OMV cost breakdown

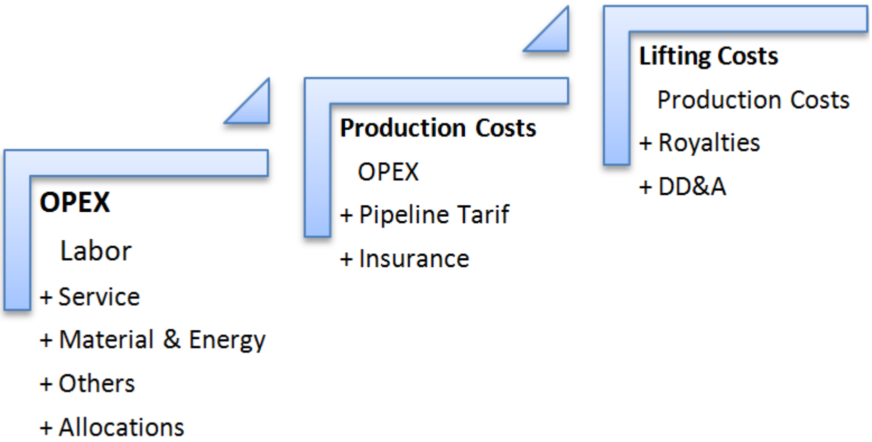

Figure 15: OMV cost breakdown[80]

4.1.1 Operating Costs

OPEX in OMV Austria are defined by the sum of

- Labor
- Service
- Material & Energy
- Other Operating Costs

[80] N.B. OMV SAP Structure

- Allocations

These five divisions are split and explained exemplarily in the following. The breakdown is based on the OMV SAP Structure of 2012 from Area 2 (Matzen Oil).

Figure 16 shows a segmentation of labor costs. All personnel costs and fringe costs inclusive expenditures for pension are included.

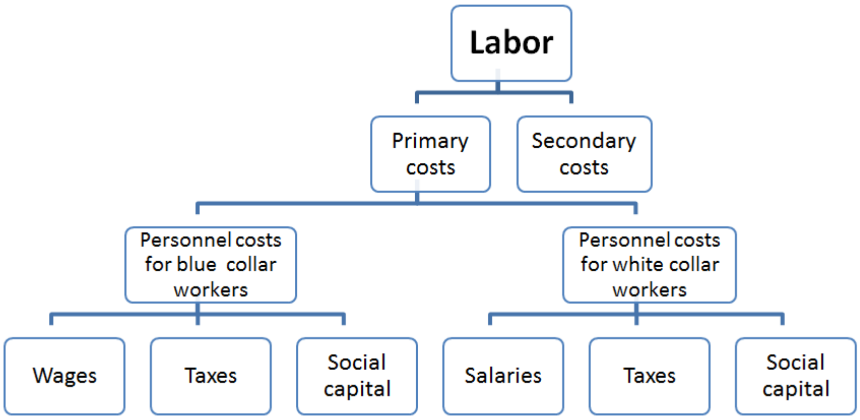

Figure 16: Split of labor costs[81]

Costs for labor are split into two divisions. These are primary and secondary costs. Primary costs are split again in personnel costs for blue-collar worker and costs for white-collar worker. Both contain wages & salaries, taxes and social capital.

All wages (and quoted wages) for blue collar workers are included in the array wages. Other costs that arise in that array are single payments for workers. The same is for white collar workers. All salaries (and quoted salaries) are contained in the array salaries. Taxes are comprised of social expenditures, local tax and family allowance for both, blue and white collar workers. Social capital consists of contribution to the pension fund and severance indemnity.

Secondary costs are minor compared to primary costs. The former include all accruing costs for internal labor.

[81] N.B. OMV SAP Structure

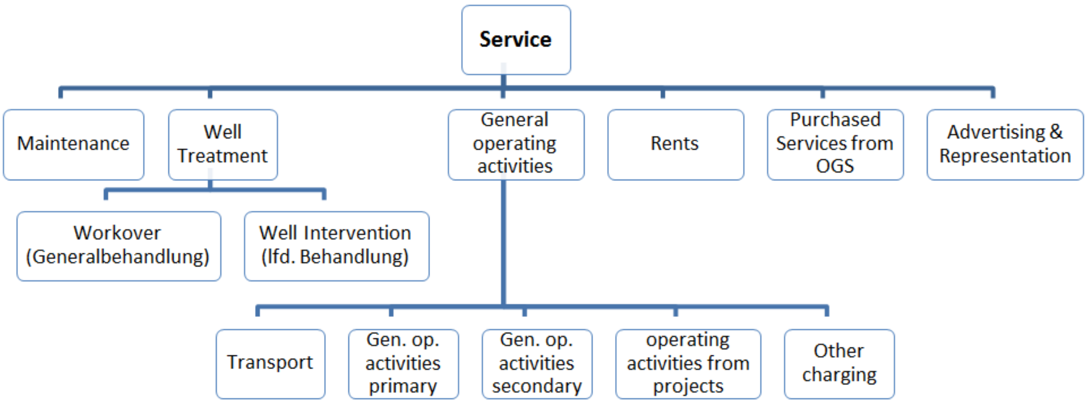

Figure 17: Split of service costs[82]

Figure 17 is a depiction of the service costs split. Service comprises all expenses for services related to producing oil. It is divided in six sub-categories and these are Maintenance, Well Treatment, General Operating Activities, Rents, Purchased Services from OGS and Advertising & Representation. Due to the extent of the service division, the sub-categories are explained separately and split in the figures below:

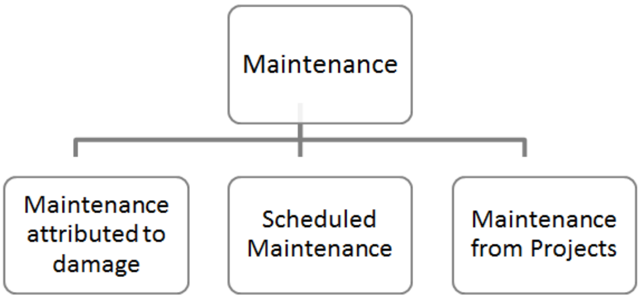

Figure 18: Split of maintenance costs[83]

In each of these three sub-sections of maintenance, costs are split into three types. These are costs for external services, internal services (OMV) and material (see chapter 3.6.1).

Costs for Maintenance are all costs for activities of minor repair as well as the replacement of smaller components. Figure 18 shows an illustration of the Maintenance segmentation. It is split into 'Maintenance attributed to damage', 'Scheduled Maintenance' and 'Maintenance from Projects'. Costs for Maintenance are divided in each section into external, internal (OMV) and material. Some examples of each section are shown below. It often includes in each section the same maintenance activities.

Examples for 'Maintenance attributed to damage' can be:

- Repairs of pumping units
- Remediate for pipe burst

[82] N.B. OMV SAP Structure
[83] N.B. OMV SAP Structure

- Repairs of X-mas tree
- Repairs of plunger pump
- Repairs of pressure line
- Plane the well site
- Repairs of any damages on properties (e.g. repair of sanitary installations)
- etc.

'Scheduled Maintenance' often overlaps with 'Maintenance attributed to damage'. Examples can be:

- Metalwork
- Repairs of line connections
- Repairs on the well site (e.g. repair of parking place and access protection)
- Service for fire alarm system
- Service for separators and compressors in LOEMST
- etc.

'Maintenance from Projects' can consist of:

- Repairs of roads, well site vehicle access and potholes
- Costs for engineering drawings
- Repair of pumping unit gear boxes

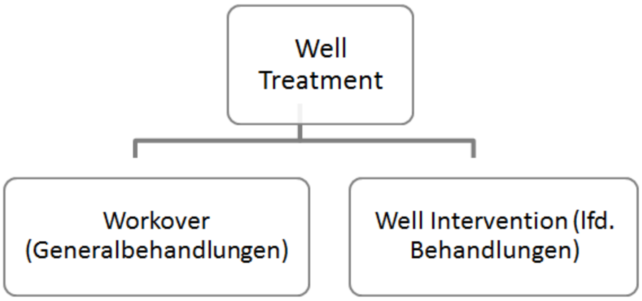

Figure 19: Split of well treatment costs[84]

Well Treatment is split into Workover and Well Intervention (see definition in chapter 3.5). Both sections are divided into external services, internal services (OMV) and material. Workover is defined as comprehensive and consistently rehabilitation work to restore, maintain or improve the production of an already completed well. Workovers are operations where the well is re-entered at a subsequent time after first completion. The definition

[84] N.B. OMV SAP Structure

of workover is not valid for drilling into a new formation.[85] Examples for workover can be seen in chapter 3.3.1.

In general, costs for well interventions are charged to orders and split into the above mentioned fractions (external services, internal services and material). 'Material' contains costs for internal material, whereas 'internals services' is comprised of equipment and personnel. The fraction 'external services' involves external material and external personnel. Nevertheless, the complete order of well intervention is charged to the section 'service'. This means, that there are also personnel costs and material costs included.

A workover is capitalized if successful. If not successful, the costs stay capitalized until the activities for workovers are completed. Afterwards, the costs are charged to the relevant cost center and depreciated.

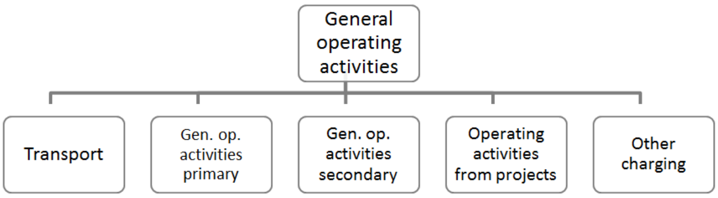

Figure 20: Split of general operating activity costs[86]

The division Transport is mainly comprised of mileage allowance. The costs for General operating activities consist for the most part of General operating activities secondary. Examples therefore are "Kärcher" workings, drawing the oil well basement, winter road maintenance, repair of pipe bursts, re-vegetate outdoor facilities, investments for pump jack, gas/liquid analysis, laboratory analysis, transport operations by truck, evaluation of samples, service operations for gas lift supply, insulating activies, cleaning of separators and surveying work.

Examples for *Operating activities from projects* are:

- Polymer pilot laboratory analysis
- Costs for project management
- Costs for planning purposes
- Digitalization of plans
- Costs for external project teams[87]

The sub-division 'Rents' is mainly composed of rents for the use of properties occupied by the surface installations that are necessary to produce oil. 'Purchased Services from OGS' is split into Office Infrastructure and General Solutions whereas Office Infrastructure contains IT-PC-Services and IT-Telephony and General Solutions contains medical attendance and advanced training.

'Advertising & Representation' involves travel expenses and that again are composed of:

- Travel expenses for blue-collar worker domestically

[85] C.f. OMV Konzernbilanzierungshandbuch (2012), p. 248: after consultation with Kammlander Bernd; EAFAT-C Controlling

[86] N.B. OMV SAP Structure

[87] N.B. OMV SAP Structure

- Travel expenses for blue-collar worker abroad
- Travel expenses for white-collar worker domestically
- Travel expenses for white-collar worker abroad

Other expenses for 'Advertising & Representation' are self-improvement for blue-collar worker and white-collar worker. 'Processing of associated gas' is another matter that is cited under 'Advertising & Representation'. By taking a closer look into the structure of SAP, it could be seen that the costs of 'processing associated gas' are not added up to the costs of 'Advertising & Representation'. For that reason, it should be watched out carefully for analyzing purposes.[88]

As the name hints, 'Material & Energy' is split into two sectors. Material is split into the cost divisions of internal products, primary costs material and secondary costs material. Internal products are all products that are produced by OMV from petroleum in the refinery in Schwechat.

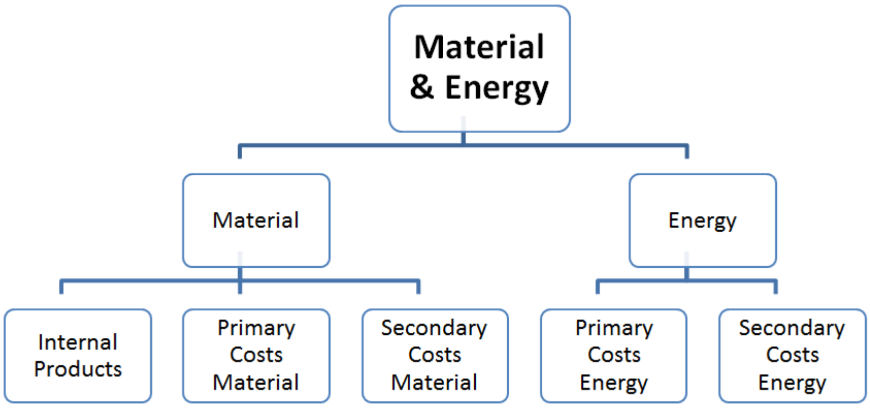

Figure 21: Split of material & energy costs[89]

Examples for internal products can be:

- Diesel
- Engine oils
- Highly compressed natural gas
- Corrosion inhibitor
- Compressor oil
- Lubricants[90]

'Primary costs material' are costs for not encamped materials, facility specific components, drilling and production material, chemical substances (laboratory material), seals, gum, leather, electric materials, equipment for fire brigade, hoist (chains and ropes), industrial requirements (mainly tools, motor vehicle spare parts (breakdown triangle, first aid box,

[88] N.B. OMV SAP Structure
[89] N.B. OMV SAP Structure
[90] N.B. OMV SAP Structure

towline), roller bearing and friction bearing, measuring and control technique, standard parts (screws, female screw, flat washers), piping components, welding material, work clothing, cleaning material, third-party products. 'Secondary costs material' are costs comprised of material overheads for stock material.

Energy is split into primary costs energy and secondary costs energy. The former is composed of costs for water (steam) whereas the latter comprises costs for water, electric current and natural gas. For natural gas it is important to distinguish between charge (energy production by means of power-heat coupling) and discharge (gas own consumption).[91]

Figure 22 shows the structure of other operating costs. Cost for crop damage, other taxes & charges and other expenditures drop into the sector of other operating costs. Crop damage involves costs for way leaves and damage on open fields. Other taxes & charges are comprised of other taxes like land taxes and land value. These taxes have to be disbursed to the individual communities. Other components are chamber apportionments, motor vehicle taxes, pension fund contributions, other charges and fees.[92]

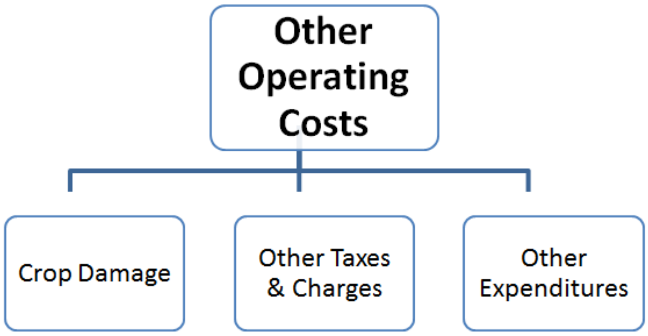

Figure 22: Split of other operating costs[93]

All costs that cannot be directly attributed to individual areas are allocated (see chapter 3.6.1). Figure 23 shows the split of allocations. Considering the allocation from support area, there are two areas of importance for oil production. These are allocations from support oil and allocations from support energy. The former consists of costs for waste management, processing of associated gas and liftgas, costs for control units, operation technique, water flooding, extraction technology materials, tankfarm in Auersthal and oil production in general. The latter is composed of costs for current supply, gas conversion into electricity, heat supply and processing of industrial water.

Allocation from administration & staff management also consists of costs for telecommunication systems and central process management system. Other allocations are Allocations from maintenance, allocations from tubings & sucker rods, allocations from liquidations, allocations from workovers, and allocations from infrastructure (personnel infrastructure, occupancy costs, costs for property management).[94]

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[91] N.B. OMV SAP Structure
[92] N.B. OMV SAP Structure
[93] N.B. OMV SAP Structure
[94] N.B. OMV SAP Structure

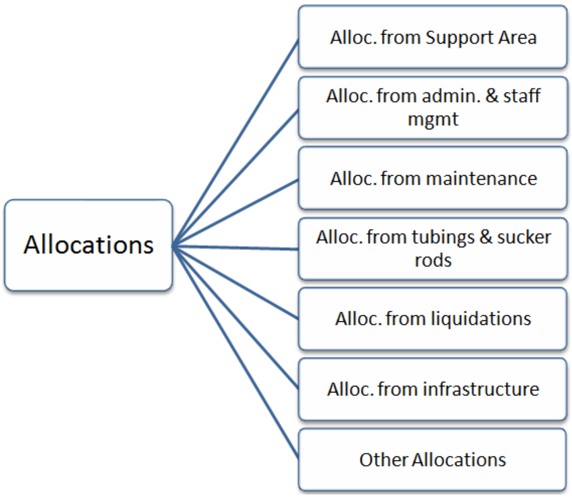

Figure 23: Split of allocations[95]

Allocations from tubings & sucker rods may cause confusion. After purchasing, tubings & sucker rods are capitalized. Then they are assembled and after a certain production time, they have to be exchanged. De-assembling and storing them cause costs. These are then allocated over the OPEX to the area of interest.

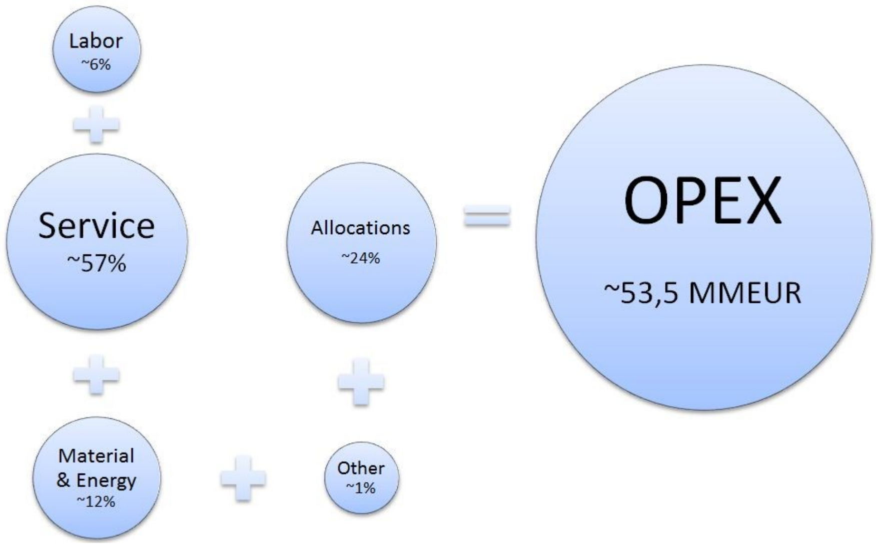

Figure 24: Percentage OPEX from area 2 (Matzen oil) 2012

Figure 24 shows the distribution of the OPEX of area 2 (Matzen oil) of the year 2012. The sector Service represents the lion's share of total OPEX with about 57%. The main cost driver of that division was well treatment with 44% (from that 28% workover and 72% well intervention) of the total service division followed by maintenance (25%), treatment of associated gas (19%), general operating activities (9%). The rest of the service costs (rents,

[95] N.B. OMV SAP Structure

purchased services from OGS, travel expenditures etc.) amounted to ~3%. The second biggest sector was that of Allocations with about 24% of total OPEX. These costs were mainly affected by allocations from the area support (oil and energy) with about 76% of total allocations followed by administration & staff management (15%), other allocations (9%), allocations from tubings & sucker rods (4%). It is obvious that the amount is too high by adding up the percent of allocations. So it must be clear that these charges are faced with 4% of discharge (allocation from support oil). The third biggest sector was that of Material &Energy with about 12% of total OPEX.

4.1.2 Production costs

Production costs in OMV Austria are defined as the sum of

- OPEX
- Pipeline Tariff
- Insurance

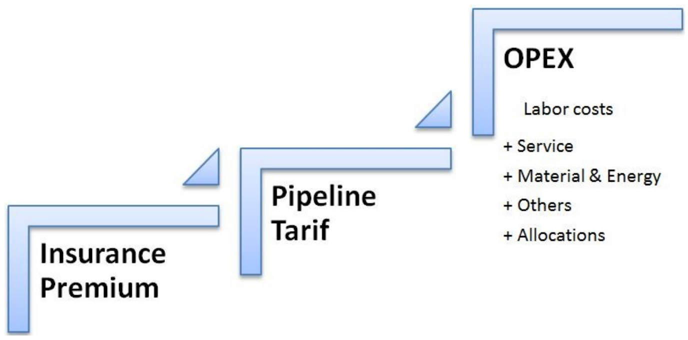

Figure 25: OMV Austria production costs breakdown[96]

$$Production\ Costs\ per\ Unit = \frac{Total\ Production\ Costs\ [boe]}{Production\ Volume\ [boe]}$$

Formula 9: Production Costs per Unit[97]

To use Formula 9 in a correct way it is important to use the 'total production volume' that is shown in Figure 27 as Wellhead Production for 'Production Volume [boe]' in the denominator of the fraction.

[96] N.B. OMV SAP Structure

[97] Controlling Manual OMV Group (2012), p. 96; after consultation with Kammlander Bernd; EAFAT-C Controlling

4.1.3 Lifting costs

Lifting costs in OMV Austria are defined as the sum of

- Production costs
- Royalties
- DD&A

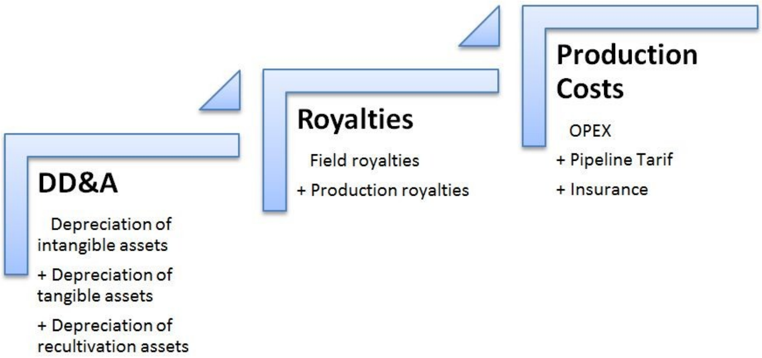

Figure 26: OMV Austria lifting costs breakdown[98]

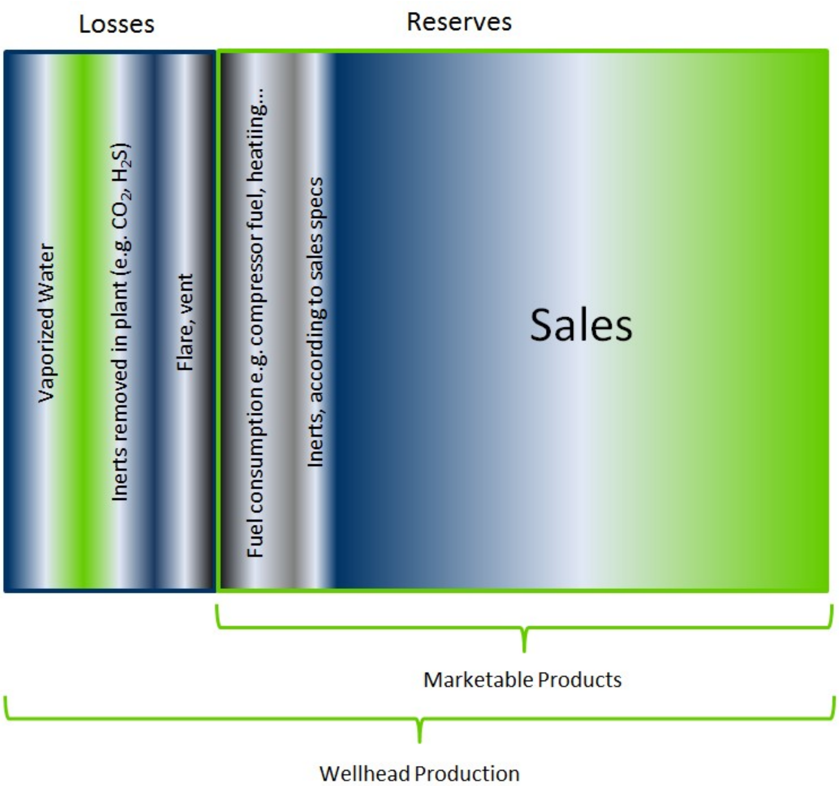

Figure 27: Marketable products[99]

[98] N.B. OMV SAP Structure
[99] After consultation with Kammlander Bernd; EAFAT-C Controlling

To use Formula 10 in a correct way it is important to use only the 'Sales' shown in Figure 27 for 'Sales Volume [boe]' in the denominator of the fraction.

$$Lifting\ Costs\ per\ Unit = \frac{Total\ lifting\ costs\ [EUR]}{Sales\ Volume\ [boe]}$$

Formula 10: Lifting Costs per Unit[100]

4.2 Matzen Oilfield – Cost center sequence

The oil is produced from individual wells. All costs that accrue in all oil wells are accumulated in the cost center 'Oelsonden Matzen 223220'. These are costs like chemical substances (anticorrosives), supplies like fuels, materials that support production, power and gas for heater treater.[101]

From the individual wells it is conveyed to LOEMSTs (life oil metering stations) and LOESSTs (life oil collecting stations) via life oil piplelines. All costs incurred for these pipes are accumulated in the cost center 'Lebendölleitung MA 223350'[102]. Once the oil is collected and metered, it is led into the gas and oil separation plant (GOSP) in Auersthal and Matzen.

There the oil is treated and separated (water content ~5%). All costs incurred in the terrain of GOSP Matzen plus the costs for operational personnel belong to the cost center 'GWST Matzen 223310'[103]. Costs that accumulate in the terrain of GOSP Auersthal as well as costs for operational personnel are counted among the cost center 'GWST Auersthal 223380'[104]. 'GWST Auersthal' includes not only costs of the separation plant itself. There are also costs involved from some LOEMSTs, LOESSTs and related life oil conduits:

- LOEMST Ma IX
- LOEMST Ma XV
- LOEMST Ma XVI
- LOESST Ma VIII
- LOESST Ma IX A, Ma IX B, Ma IX C
- LOESST Ma XV A, Ma XV B

Since OMV Austria E&P has an oil delivery contract with the refinery in Schwechat implying that the delivered oil has to have a water content of less than 1%, the oil has to be treated again after processing in GOSP Matzen and Auersthal. This occurs by pumping separately two sorts of oil, Asphaltic-oil & Paraffinic-oil (A-oil &P-oil), to the tankfarm in Auersthal. The cost center therefore is 'Tanklager Auersthal 223255'[105]. From GOSP

[100] C.f. Controlling Manual OMV Group (2012), p. 96; after consultation with Kammlander Bernd; EAFAT-C Controlling
[101] After consultation with Vogt Johann; EATAP-A Area Oil A
[102] After consultation with Stur Franz; EATA-L Pipeline Operations
[103] After consultation with Hess Josef; EATAP-B Area Oil B
[104] After consultation with Hess Josef; EATAP-B Area Oil B
[105] After consultation with Walk Johann; EATAP-B Area Oil B

Matzen, A-oil and P-oil is pumped to the tankfarm. This oil is already pre-processed with a water content of about 5%. The rest of the Matzen oil is pumped from several LOEMST to the GOSP Auersthal. It is in close proximity to the tankfarm of Auersthal. After oil processing in GOSP, the oil is pumped to the tankfarm and treated to a water content of less than 1%. Gas that accumulates due to oil processing, is led to KSAU (compressor station Auersthal) and accruing water is pumped to the water treatment plant in Schönkirchen or directly to the water injection ring.

All costs that accrue due to the processing process in the tankfarm in Auersthal belong to the cost center '223255'[106]. Costs that accumulate are costs for ongoing operating activities, costs for labor, maintenance etc. Heat supply for the tankfarm is a separate cost center and is given by the compressor station in Auersthal.

A cost center that is related to 'Tanklager Auersthal 223255' is 'Sammel und Verpumpung 223265'. This cost center involves all costs for service and maintenance for the pipes between:

- GOSP Matzen – Tankfarm Auersthal
- Tankfarm Auersthal – Tankfarm Lobau

The accruing water from GOSP Matzen and Auersthal is led to the water treatment plant (WTP). The WTP in the village Schönkirchen close to Gänserndorf is split into two cost centers[107]. One of it is 'Wasserfluten Ost (223256)'. All costs incurred in the WTP to clean and process the formation water are accumulated in this cost center. Costs for repairs accrued for the required facilities as well as costs for personnel, energy etc. are assigned to that cost center. The other one is 'Schlammaufbereitung (223266)'. This cost center in the area of the water treatment plant Schönkirchen is processing the oil sludge. All appropriate costs for operating, and maintenance of the facilities to process the sludge are accumulated in this cost center.

From the WTP, the processed formation water is pumped into two pipe rings that are split from each other. On is the so called Injection Ring. About 60% of the treated water is brought into that ring. These 60% are re-injected in producing horizons (e.g. 8th TH, 16th TH) and it serves about 30-35 injection wells. The other one is the Conglomerate Ring. The name refers to the Aderklaa Conglomerate. About 40% of the treated water is injected into the Aderklaa Conglomerate where no production activities are performed any more. The Conglomerate ring controls about 10-15 injection wells.

Due to the fact that for the Matzen oil more water is produced than injected, about 40% of the treated water has to be injected into the Aderklaa Conglomerate. These 40% do not conduce for production but it is deposited in the underground. The other 60% are injected into the respective horizons (e.g. 8th TH, 16th TH). The WTP in Schönkirchen delivers a water quality of ~2 ppm oil and ~1 ppm solids.

In the course of the MORE program, the western part of the 16th TH (Bockfließ Area) should be supplied by a new WTP close to the GOSP Auersthal where water processing is performed with hydrocyclones. A satisfaction of the water quality is given according to the motto "as good as necessary", in fact ~200 ppm oil and ~10 ppm solids. The eastern part of the 16th TH and all other horizons of the Matzen oilfield are conduced furthermore of the WTP in Schönkirchen.

[106] After consultation with Walk Johann; EATAP-B Area Oil B

[107] After consultation with Winter Josef; EATAE-W Water Treatment Plant

Two other cost centers associated with the water treatment plant Schönkirchen are[108]:

'Flutsonden Matzen (223257)': The cost center for flooding involves costs for all injection wells necessary. For flooding, all injection wells of, 8^{th} TH, 9^{th} TH, 16^{th} TH – Bockfließ Area, Schönkirchen Tief, Aderklaa conglomerate, Hochleiten/Pirawarth, Erdpress and Ebenthal are involved.

All surface and subsurface installations of the injection wells and sites belong to that cost center. Another component of '223257' is the injection ring (not conglomerate ring) and conduits between injection wells and injection ring.

'Wasserinjektion Südfeld (223261)'*:* The second ring of WTP Schönkirchen, conglomerate ring) is part of that cost center. It conduces about 10-15 injection wells that do not serve any production. Furthermore, '223261' is a kind of "support cost center" because the following parts also belong to it:

- Pipes of GOSP Auersthal & GOSP Matzen to the WTP Schönkirchen
- Water pumps and tanks of GOSP Auersthal and GOSP Matzen

In Appendix D, a summarized schematic of the interaction of the main individual cost centers in the Matzen field is shown. The fluid is extracted from the reservoir by means of ESPs and SRPs (Oelsonden Matzen 223220). Once the fluid is lifted to the surface it is brought via pipelines (cost center of the individual LOEMSTs and LOESSTs) to LOEMSTs and LOESSTs. In a LOEMST, the oil is collected and measured (by means of single test separators). In a LOESST it is only collected. For measuring purposes the oil is brought via single measuring lines to a LOEMST. After collecting and measuring of the oil, it is led to one of both GOSPS (GWST Auersthal 223380 and GWST Matzen 223310). In a GOSP, the oil, water and gas mixture is treated. Oil and water is led into the tank farm (Tanklager Auersthal 223255) and gas into the compressor station (Gasstation AU Inland 243231). Water is either directly brought into the injection system (Flutsonden Matzen 223257) or into the water treatment plant (WTP Schönkrichen 223256, 223261 and 223266). The separated oil from the tank farm and the gas from the gas station are then finally send upon for the purpose of sale.

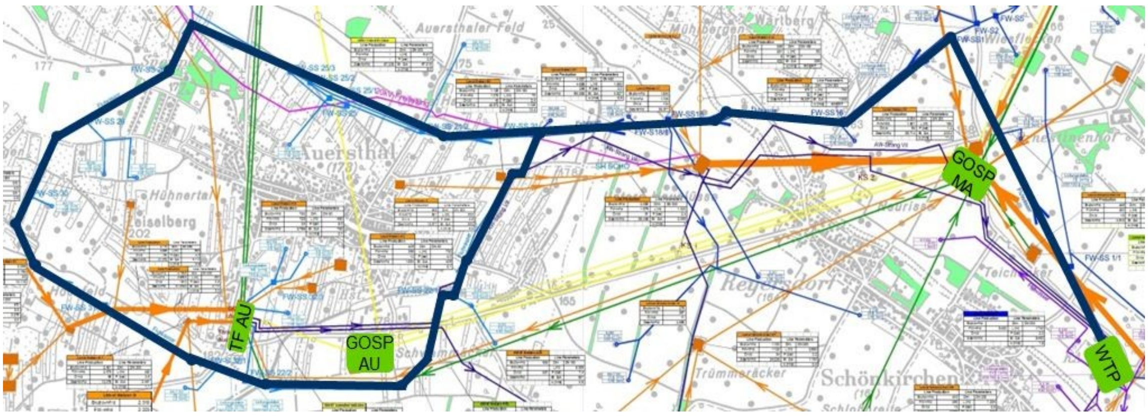

Figure 28: Schematic of water handling on the 16th TH[109]

[108] After consultation with Winter Josef; EATAE-W Water Treatment Plant

Figure 28 indicates the water handling of the Bockfließ Area. Thereby it can be seen that a long distance has to be hurdled to reach the water treatment plant in Schönkirchen. Water management will therefore be a key issue for re-development of the Bockfließ area to hold the operating costs at a low level. The following chapter and sub-chapters attend to the water management and indicate to options, how produced water can be handled in the Bockfließ area.

[109] After consultation with Nusser Heinz; EATP-1 Project Management 1

5 Options for OPEX optimization

5.1 SRPs & ESPs

For oil lifting, OMV uses electric submersible pumps ESP, sucker rod pumps SRP and the method of gas lift GL. After breaking down the OPEX and after investigation of the calculation of energy consumption it was obvious that there is a lack of precision in planning whether to install ESP or SRP for pumping purpose and thereafter total OPEX for re-development projects. The common approach for planning the energy consumption for new wells was to use only one charge rate for downhole pumps (ESP, SRP). For the method of gas lift an extra charge rate already existed.

An investigation showed that the approach could not be completely correct due to the fact that ESPs can produce much higher rates. As a consequence of higher rates the energy consumption must be higher than for rod pumping and also well interventions have to be conducted in smaller intervals. Another closer consideration was on the fact that there must be a difference in the "mean-time-between-failure" MTBF for both pumps. These aspects are described by life-cycle-costing LCC (25 years) for both pumps. Therefore investment costs (CAPEX), costs for well interventions and energy were examined.

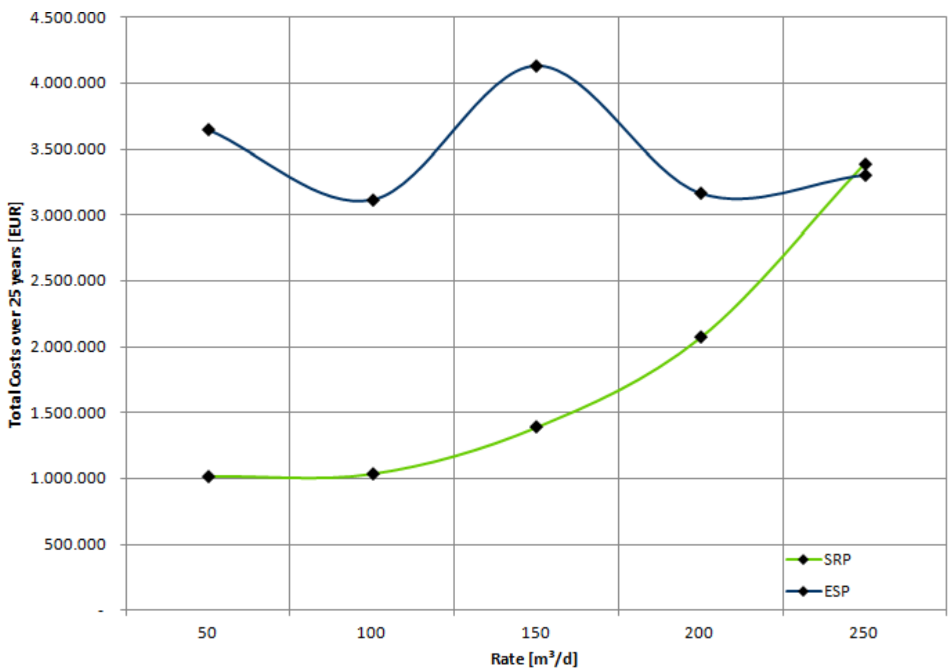

Figure 29: SRP vs. ESP over 25 years[110]

For life-cycle-costing of sucker rod pumps and electric submersible pumps five different scenarios with different production rates (50, 100, 150, 200, 250 m^3/d) were determined.

[110] After consultation with Florian Thomas; EATS-E Production Engineering

The rate 50 m³/d indicates the range of 25 – 75 m³/d, 100 m³/d hints to 76 – 125 m³/d, 150 m³/d indicates the range of 125 – 175 m³/d, 200 m³/d means the margin of 175 – 225 m³/d and 250 m³/d shows the range of 225 – 275 m³/d. By investigating the mean-time-between-failure of both pumps the costs for well interventions could be obtained. Another issue for this calculation was to examine the net operating time of both pumps. These aspects were accomplished by means of the OMV Information Management in Gänserndorf. In the following, costs over a period of rod pumping is explained (Table 6 – Table 9).

To calculate the capital expenditures for sucker rod pumping, it was important to receive costs for the foundation, pump unit, pump unit installation, E-motor, E-container, well monitoring, well site installation, sucker rods, tubing, well head & X-mas tree, downhole pump and costs for workover.

Table 6: CAPEX – SRP[111]

CAPEX	SRP_{q1}	SRP_{q2}	SRP_{q3}	SRP_{q4}	SRP_{q5}
Foundation	10.000	10.000	10.000	10.000	10.000
Pump Unit	88.000	88.000	88.000	88.000	88.000
Pump Unit Installation	17.000	17.000	17.000	17.000	17.000
E-Motor	3.000	3.000	3.000	3.000	3.000
E-Container	25.000	25.000	25.000	25.000	25.000
Well Monitoring	20.000	20.000	20.000	20.000	20.000
Well Site Installation	40.000	40.000	40.000	40.000	40.000
First Sucker Rods	13.000	13.000	13.000	13.000	13.000
First Tubing	12.000	12.000	20.000	20.000	20.000
Well Head inkl. X-Mas Tree	70.000	70.000	70.000	70.000	70.000
First Downhole Pump	3.400	4.800	4.800	12.200	15.000
Workover	100.000	100.000	100.000	100.000	100.000
CAPEX TOTAL	401.400	402.800	410.800	418.200	421.000

To see how often a well intervention has to be performed, it was essential to investigate the mean-time-between-failure. The MTBF was determined by figuring out the installation date and the removal date. By subtracting the installation date from the removal date, the MTBF was obtained. For that calculation, about 130 data sets were gathered from the Bockfließ Area. The results can be seen in Figure 30. Best results for rod pumping referred to MTBF can be obtained from rates of about 100 m³/d. By increasing the production rate, the MTBF decreases. For a rate of 150 m³/d a MTBF of about 740 days was observed and for a rate of 200 m³/d a MTBF of only 385 days was perceived.

[111] Assumptions based on OMV estimations; after consultation with Florian Thomas; EATS-E Production Engineering

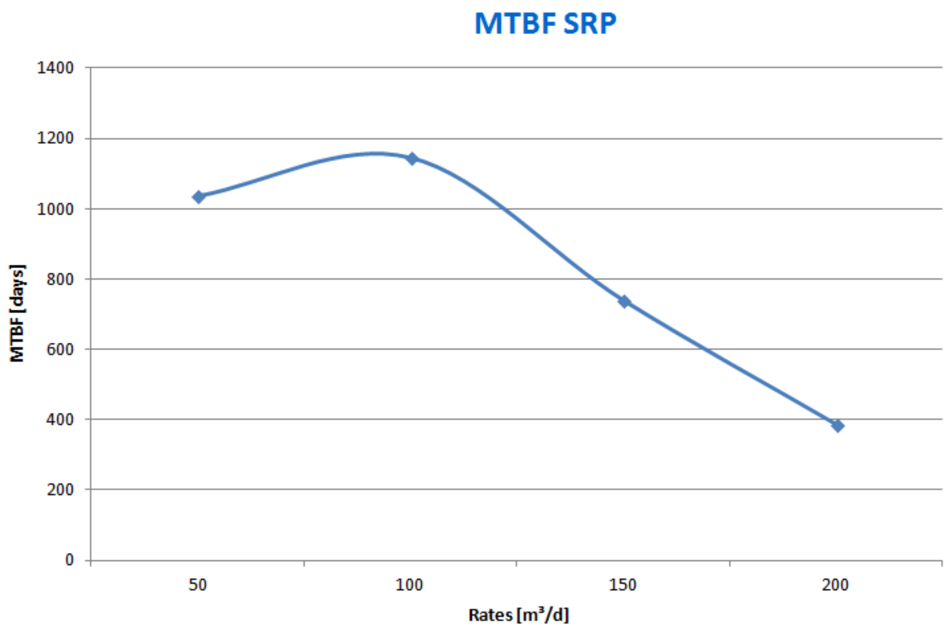

Figure 30: MTBF – SRP[112]

For calculating the costs for well intervention, several orders from SAP were gathered and the average was calculated. As a result, 53.000 EUR per well intervention should be taken into account.

Table 7: Costs for well interventions – SRP

Well Interventions	SRP_{q1}	SRP_{q2}	SRP_{q3}	SRP_{q4}	SRP_{q5}
MTBF [d]	1040	1145	740	390	200
Well Intervention TOTAL	465.024	422.380	653.547	1.240.064	2.418.125

The following formula was used to calculate well intervention total costs:

$$Cost\ for\ WI = \frac{Period\ [years] \times 365 \left[\frac{days}{year}\right]}{MTBF\ [days]} \times Costs\ for\ WI\ per\ well\ [EUR]$$

Formula 11: Costs for total WI

Two essential parameters were used to calculate the energy costs for rod pumping over 25 years. These parameters are the consumed power and the downtime. Energy costs were determined with the following formula:

[112] N.B. Calculation is based on Data obtained from the OMV Information Management; after consultation with Bohrn Wolfgang; EATS-I Information Management

$$Energy\ costs = \left(365\left[\frac{days}{year}\right] - Down\ Time\ \left[\frac{days}{year}\right]\right) \times Perid\ [years] \times Power\ [kW] \times PowerCosts\ \left[\frac{EUR}{kWh}\right]$$

Formula 12: Total Energy Costs – LCC

Table 8: Costs for energy – SRP

Energy Costs	SRP$_{q1}$	SRP$_{q2}$	SRP$_{q3}$	SRP$_{q4}$	SRP$_{q5}$
Measured Power [kW/d]	192	264	408	528	720
Downtime [d]	5	4	7	13	26
Energy Costs TOTAL	155.557	214.159	328.731	418.054	549.909

Total costs after 25 years are calculated by the sum of CAPEX, costs for well interventions and energy costs. Table 9 shows a summary of total costs for rod pumping for each case. A graphic representation is shown in Figure 29 (green line).

Table 9: Total costs after 25 years – SRP

	SRP$_{q1}$	SRP$_{q2}$	SRP$_{q3}$	SRP$_{q4}$	SRP$_{q5}$
CAPEX	401.400	402.800	410.800	418.200	421.000
Well Interventions	465.024	422.380	653.547	1.240.064	2.418.125
Energy	155.557,38	214.159,05	328.730,84	418.054,15	549.909,00
Total costs after 25 years	1.021.981	1.039.339	1.393.078	2.076.318	3.389.034

The same procedure was performed for life-cycle-costing for electric submersible pumps. To calculate CAPEX some assumptions for several types of costs were needed. These assumptions are costs for E-Container, well monitoring, well site installation, first tubing, wellhead, first electric submersible pump, workover and downhole gauge. Assumptions for CAPEX are shown in the table below and they are based on OMV estimates.

Table 10: CAPEX – ESP[113]

CAPEX	ESP$_{q1}$	ESP$_{q2}$	ESP$_{q3}$	ESP$_{q4}$	ESP$_{q5}$
E-Container	25.000	25.000	25.000	25.000	25.000
Well Monitoring	20.000	20.000	20.000	20.000	20.000
Well Site Installation	40.000	40.000	40.000	40.000	40.000
Cable (in ESP)	30.000	30.000	30.000	30.000	30.000
Tubing	12.000	12.000	12.000	12.000	12.000
Well Head	70.000	70.000	70.000	70.000	70.000
ESP	80.000	80.000	95.000	95.000	98.000
Workover	190.000	190.000	190.000	190.000	190.000
Downhole Gauge	13.000	13.000	13.000	13.000	13.000
CAPEX TOTAL	480.000	480.000	495.000	495.000	498.000

[113] Assumptions based on OMV estimations; after consultation with Florian Thomas; EATS-E Production Engineering

About 50 data sets were used to calculate the MTBF for ESPs, 16 of them from St. Ulrich, 6 from Hauskirchen, 3 from Muehlberg, 10 from the Bockfließ Area, 10 from the Matzen Area, 4 from Schoenkirchen and 2 of them from Breitenlee.

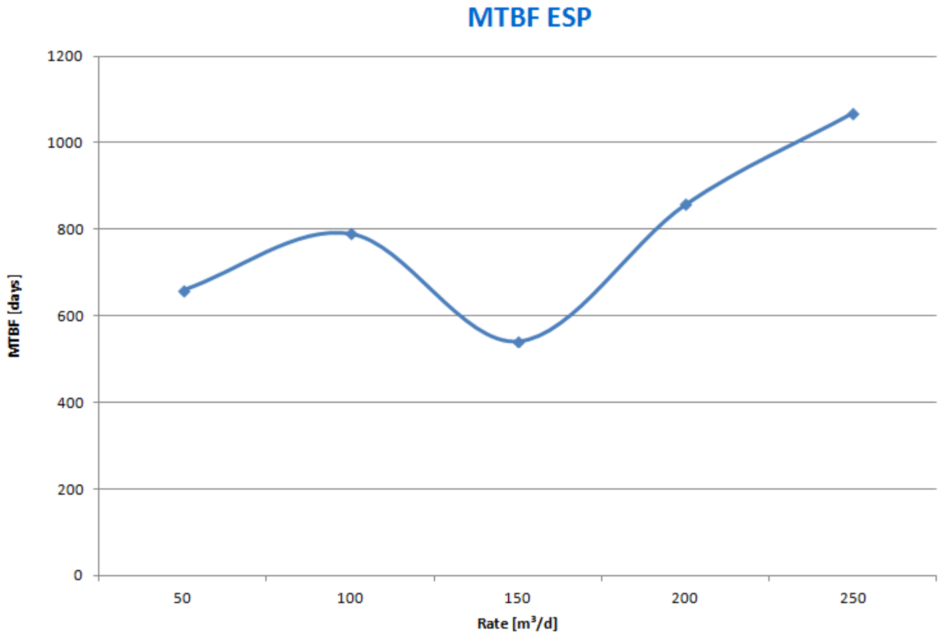

Figure 31: MTBF – ESP[114]

The results can be seen in Figure 31. Best results for ESPs referred to MTBF can be obtained from rates of higher than about 200 m^3/d. By increasing the production rate, the MTBF even increases. For a rate of 200 m^3/d a MTBF of about 860 days was observed and for a rate of 250 m^3/d a MTBF of 1.070 days was perceived.

For calculating the costs for well intervention, several orders from SAP were gathered and the average was calculated. The costs for well interventions for ESPs can be seen in the Appendix E. As a result, 170.000 EUR per well intervention should be taken into account. As for the calculation for SRP, Formula 11 was used to calculate total well intervention cost.

Table 11: Costs for well interventions – ESP

Well Interventions	ESP_{q1}	ESP_{q2}	ESP_{q3}	ESP_{q4}	ESP_{q5}
MTBF [d]	660	790	540	860	1070
Well Intervention TOTAL	2.350.379	1.963.608	2.872.685	1.803.779	1.449.766

To calculate the energy costs for ESPs, the same procedure as for the SRP calculation was executed and Formula 12 was used for the determination.

[114] N.B. Calculation is based on Data obtained from the OMV Information Management; after consultation with Bohrn Wolfgang; EATS-I Information Management

Table 12: Costs for energy – ESP

Energy Costs	ESP_{q1}	ESP_{q2}	ESP_{q3}	ESP_{q4}	ESP_{q5}
Measured Power [kW/d]	1.020	840	960	1.080	1.680
Downtime [d]	8	6	9	6	5
Energy Costs TOTAL	819.906	677.625	767.960	872.511	1.361.648

Total costs after 25 years are calculated by the sum of CAPEX, costs for well interventions and energy. Table 13 shows a summary of total costs for ESPs for each rate. A graphic representation is shown in Figure 29 (blue line).

Table 13: Total costs after 25 years – ESP

	ESP_{q1}	ESP_{q2}	ESP_{q3}	ESP_{q4}	ESP_{q5}
CAPEX	480.000	480.000	495.000	495.000	498.000
Well Interventions	2.350.379	1.963.608	2.872.685	1.803.779	1.449.766
Energy	819.906	677.625	767.960	872.511	1.361.648
Total costs after 25 years	**3.650.285**	**3.121.232**	**4.135.645**	**3.171.290**	**3.309.414**

The idea of the above described approach was determined for the re-development project Erdpress. This was a thought-provoking impulse for developing a real life-cycle-costing tool based on VDMA[115] that could be used for several facilities, components or products used in the petroleum industry. By using the method characterized in this section, the time value of money is not considered. There are also some other parameters that are not included, like quality checks of new pumps, warehousing costs or acreage costs, that can be different due to the footprint. The next section gives a well-structured calculation considering most of the essential parameters, necessary to distinguish between ESPs and SRPs.

5.2 Life-Cycle-Costing for ESPs and SRPs

In the course of the MORE Program, several ESPs are planned for the re-development of the 16th TH. As mentioned in the introduction, the MORE Program aspires to significantly enhance the NPV. This should be accomplished by increasing the gross production rate. There is no better pump to produce extraordinary rates than ESPs. But a usage of ESPs for high rates goes hand in hand with high power consumption resulting in extra costs compared to rod pumping. Another big issue is the interaction between production rate and MTBF. In the case of sucker rod pumping, the MTBF decreases with increasing production rate. This is not the case for ESPs because the MTBF increases with increasing production rate. These aspects cause in both cases extra costs if the planned pump is not adapted to a proper production rate. This implies that accurate planning is absolutely essential to operate in the future.

Therefore, to optimize the future OPEX a life-cycle-costing tool was generated by means of MS Excel based on VDMA. It is very easily structured and it can be adapted not only to

115 C.f. VDMA 34160 (2006), p. 6 et seqq.

pumps like in the example below, but also to facilities or other units, used in the petroleum industry. The tool created within this Master Thesis consists of five fields:

- General Framework
- Basic Data
- Acquisition Phase
- Operating Phase
- Disposal Phase

In the 'General Framework', the load spectrum should be defined. The idea was to state three different load types (full load, partial load, at-rest) where the sum of the distribution should always be 100%. Partial load is assumed to be half of the full load. At-rest means that there is no load, resulting in no costs for power consumption.

Table 14: LCC Tool – Input General Framework

General Framework		
Name	Description	Comment
Load Spectrum	Distribution of load types: full load, partial load and at-rest	Has to be set for each LCC prediction
Full Load	97%	
Partial Load	1%	half of full load
At-rest	2%	

In the field 'Basic Data', three parameters have to be entered:

- Life Cycle
- Rate
- Discount Rate

For these parameters, dropdown-functions are chosen to limit the input of data to a predefined range. The life cycle is defined as the timeframe of the product from acquisition to disposition. For the calculation, values in the range from 5 – 25 years can be chosen. The rate defines the gross production rate per day. The following values can be chosen:

- 0 – 75 m^3/d
- 76 – 125 m^3/d
- 126 – 175 m^3/d
- 176 – 225 m^3/d
- > 225 m^3/d

These values are based on production data of wells in the Bockfließ area.[116] After choosing the desired gross production rate, the power consumption of both pumps is defined automatically. It was important to have reliable data on the part of energy consumption because energy costs are one of the main cost drivers in field operations. Therefore power consumption values were specially metered for this thesis.[117] The values for the MTBF are also set automatically after choosing the gross rate. MTBF values are empirically determined based on data from the Information Management in Gänserndorf. Therefore, all the well

[116] After consultation with Nusser Heinz; EATP-1 Project Management 1
[117] After consultation with Gerlinger Josef; EATAT-E Elec.,Proc.&Instrum.Engineering

interventions since the year 2000 were gathered and a rate dependent MTBF was created.[118] That procedure was made for both pumps, ESPs and SRPs.

The acquisition costs for the pumps were received from the Production Engineering Department of OMV in Gänserndorf.[119] The higher the rate, the more expensive the pump but there is a significant price difference in both pump types.

The discount rate can be set by means of the dropdown function. OMV uses either 10% or 15% for discounting purposes.

Table 15: LCC Tool – Input Basic Data

Basic Data					
Pos.	Name	Description	Value ESP	Value SRP	Unit
BD1	Life Cycle	Timeframe of the product in use from acquisition to disposition	25		[years]
BD2	Rate	Gross production rate per day	> 225		[m³/d]
BD3	Power Consumption	Power Consumption of the tool to be investigated	75	30	[kW]
BD4	Discount Rate	Costs need to be discounted over the total life cycle	10		[%]
BD6	MTBF	Mean Time Between Failure	1.070	190	[days]
BD7	Pump Price	Acquisition Costs of the Pump	98.000	15.000	[EUR]

The ‚Acquisition Phase' is structured so that all the accruing costs are converted into values on the basis of one year, dependent on the MTBF. This procedure is applied for procurement costs, infrastructure costs and other acquisition costs.

Table 16: LCC Tool – Acquisition Phase

Acquisition Phase					
Pos.	Name	Description	Value ESP	Value SRP	Unit
AC	Total Acquisition Costs	Sum of Procurement Costs, Infrastructure Costs and Other Acquisition Costs over the total life cycle	547.617	448.140	[EUR]
AC1	Procurement Costs	Costs of all procurement achievements until production starts on the basis of one year	35.101	30.257	[EUR]
AC1.1	Procurement Price	Price of the product	98.000	15.000	[EUR]
AC1.2	Spare Parts Package	Price of the spare parts acquired with the product	4.900	750	[EUR]
AC1.3	Freight Charge	Transport costs of the product right up to the installation location	0	0	[EUR]
AC1.4	Customs Costs	Costs for export & import	0	0	[EUR]
AC1.5	Other Procurement Costs	Costs for other procurement achievements (e.g. safety equipment)	0	0	[EUR]
AC2	Infrastructure Costs	Costs for foundation of the installation place and product integration into the surroundings on the basis	229.000	173.500	[EUR]
AC2.1	Retooling Costs	Costs for retooling, necessary if gross production is increased; e.g. costs to exchange older pump jacks by newer ones or by ESP units (only type values in if retooling is planned of a new well is pallned)	229.000	173.500	[EUR]
AC2.2	Grid Infrastructure	Costs for setup of supply mains	0	0	[EUR]
AC2.3	Other Infrastructure Costs	Costs for other infrastructure achievements (e.g. insurances)	0	0	[EUR]
AC3	Other Acquisition Costs	Costs for other acquisitions on the basis of one year	0	0	[EUR]

Procurement costs are costs for all achievements until the production starts. Thereby, the procurement price and costs for spare parts are included. If freight charges and customs costs are not included in the procurement price, it can be entered separately. After entering the values in the sub-positions of AC1, they are summed up and converted on the basis of one year. The procurement price is linked to the input line 'Acquisition Costs of the Pump' of the 'Basic Data' field. The costs of the spare parts are assumed to be 5% of the pro-

[118] After consultation with Bohrn Wolfgang; EATS-I Information Management
[119] After consultation with Florian Thomas; EATS-E Production Engineering

curement price of the pump. For that calculation, freight charge and customs costs are included in the procurement price.

Position AC2 covers infrastructure costs. For that calculation it is assumed that these costs will accrue one time at the beginning of a project. Infrastructure costs consist of retooling costs and grid infrastructure costs. Retooling costs are accruing because if higher gross rates are desired, as in the case of the re-development of the 16th TH, newer pumping units will be necessary. Therefore, costs for site preparation, foundation, demolition of old pumping unit, installation of the new pumping unit, costs for the wellhead and X-mas tree, etc. will incur.

The 'Operating Phase' is the phase where the highest costs accrue. The main cost drivers thereby are energy costs, especially for ESPs and costs for well interventions.

At first, all costs are summed up in the data line OC1 and converted on the basis of one year. Afterwards, the total OPEX are determined by discounting the sum of all operating costs over the duration of the life cycle. The sum of data line OC1 includes the following positions:

- Maintenance: This position includes costs for overground services. Therefore, costs for labor, equipment, commodities and auxiliaries are taken into consideration. If these costs cannot be detected, a lump sum for overground services can be entered.
- Well Interventions: It includes all costs for the equipment, labor, logistics, tubing, sucker rods, downhole pump, material, planning, external services like external personnel, cable truck and site preparation. If these costs cannot be detected, costs can be entered as a lump sum.

Table 17: LCC Tool – Operating Phase

Operating Phase					
Pos.	Name	Description	Value ESP	Value SRP	Unit
OPEX	Total Operating	Sum of all operating costs over the total life cycle	780.984	1.014.374	[EUR]
OC1	Total Operating Costs per year	Sum of costs for Repair & Maintenance, WI, installation, commissioning, quality-check, acreage, energy and warehousing	86.039	111.752	[EUR]
OC1.1	Repair & Maintenance	Sum of all repair & maintenance activities per year	1.000	1.000	[EUR]
OC1.2	WI Costs per Year	Costs for WI (rig costs, tubing change costs) per year	26.573	84.142	[EUR]
OC1.3	Installation Costs	Costs of all installation achievements until production starts	0	0	[EUR]
OC1.4	Commissioning Costs	Costs of all commissioning achievements until production starts	0	0	[EUR]
OC1.5	Costs for Quality-Check	New products are checkt concerning operative readiness (costs on the basis of one year)	38	211	[EUR]
OC1.6	Acreage Costs	Costs for Acreage that OMV has to pay to landowner on the basis of one year	286	571	[EUR]
OC1.7	Energy Costs	Energy Costs for one year based on load spectrum	57.652	23.061	[EUR]
OC1.8	Warehousing Costs	Warehousing Costs for one year	491	2.766	[EUR]
OC1.9	Other Operating Costs	Other operating costs for one year (e.g. safety equipment, update costs for computer software)	0	0	[EUR]

- Installation & Commissioning Costs: These costs should only be entered if no lump-sum value is entered for well interventions because installation & commissioning costs are included in the blanked amount of well interventions. If costs for well interventions can be detected, installation & commissioning costs consist of costs for labor, travelling, equipment, wear parts, commodities, auxiliaries and operating material.
- Costs for Quality-Check: New pumps are checked concerning operative readiness. For this reason it is assumed to check a new pump one hour with a defined hourly rate.

- Acreage Costs: This consistent charge has to be paid annually to landowners. The rate therefore amounts for 0,42 EUR/m². Depending on extra profit situations or in case of vegetable growing, surcharges can be up to 70%. For this calculation, acreage costs are taken into consideration due to the fact that ESPs have a smaller surface footprint than rod pumping units.
- Energy Costs: Energy costs are dependent on the load spectrum and on the desired production rate that is defined in the field 'Basic Data'. The charge rate that OMV has to pay for one kWh is 0,09 EUR.
- Warehousing Costs: OMV has six holding areas for six pump in each case. The costs for one holding area are detected with 240 EUR.
- Other Operating Costs: This can be costs for safety equipment or update costs for computer software.

During the 'Disposal Phase', no costs are detected. Quite the contrary, there is a recovery value that amounts for 190 EUR per ton of scrap obtained from *Scholz Rohstoffhandel GmbH*.

Table 18: LCC Tool – Disposal Phase

Disposal Phase					
Pos.	Name	Description	Value ESP	Value SRP	Unit
DC	Total Disposal Costs	Sum of all disposal costs over the total life cycle	-512	-517	[EUR]
DC1	Total Disposal Costs per year	Sum of scrapping costs, recovery value, costs for logistics and other disposal costs	-57	-57	[EUR]
DC1.1	Scrapping	Costs for scrapping on the basis of one year	0	0	[EUR]
DC1.2	Recovery value	Recovery value on the basis of one year	-57	-57	[EUR]
DC1.3	Logistics	Costs for logistics (e.g. transport)	0	0	[EUR]
DC1.4	Other disposal costs	Other disposal costs on the basis of one year	0	0	[EUR]

The results of the calculation from the LCC calculation can be seen in the following figure. It can be seen that SRPs deliver better results at lower rates compared to ESPs. With increasing production rate, costs for SRPs rise stronger than costs for ESPs. This can be interpreted due to the fact that SRPs have poor values for MTBF at higher rates whereas ESPs show excellent values for MTBF at higher rates.

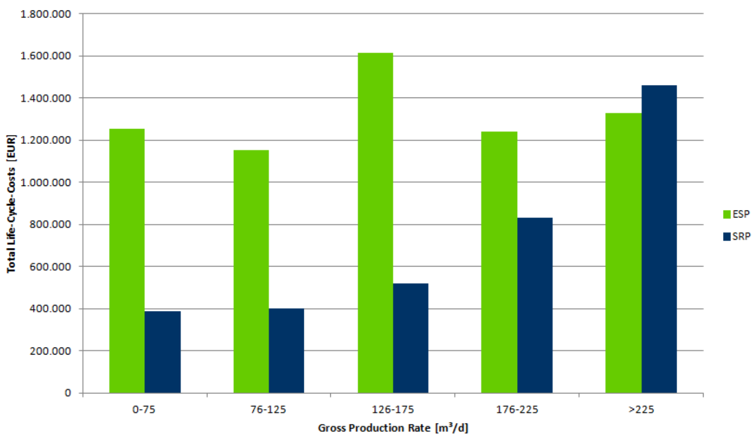

Figure 32: Results of LCC Calculation – ESPs vs. SRPs

5.3 Water Management – 16th TH Bockfließ Area

5.3.1 Field infrastructure – Bockfließ Area

The biggest project in the course of the MORE program is currently the re-development of the 16th TH and it was initiated to accelerate production. This should be accomplished by increase the gross production rate of specific well-chosen already existing production wells and by drilling additional two horizontal high capacity producers. Several concepts were elaborated for re-developing the 16th TH. The final re-development project is a combination of the scenarios of “Max oil rate” and “Max Recovery” (see chapter 2.4). Figure 33 shows a summarized schematic of the new and existing field infrastructure elements:

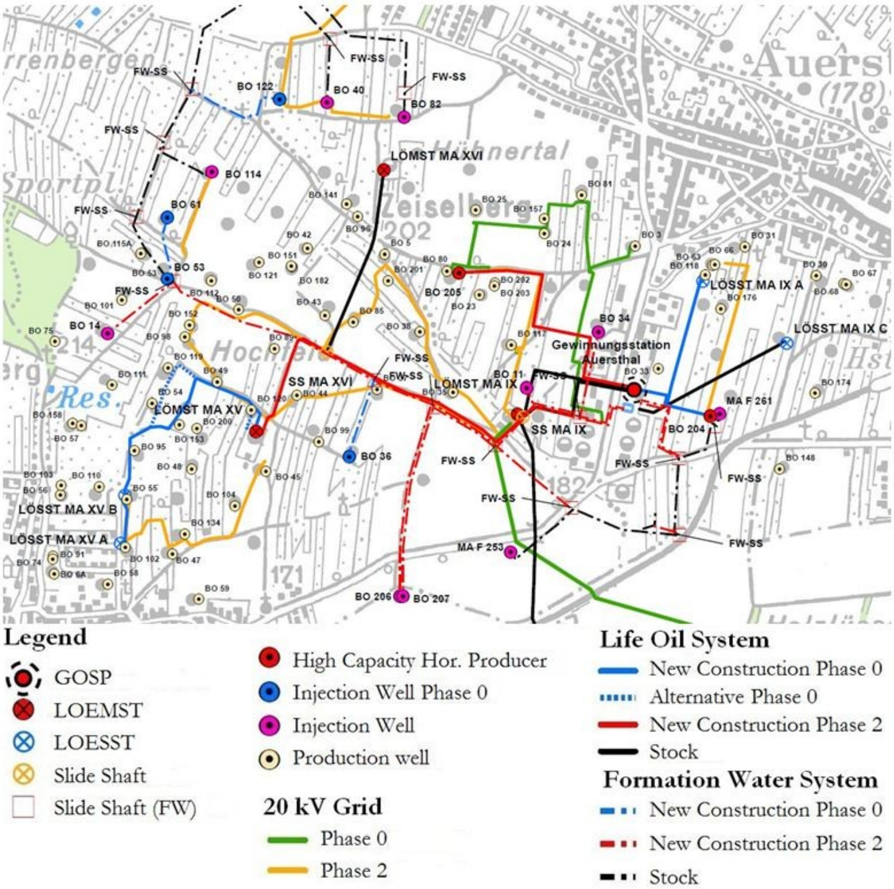

Figure 33: Re-development 16. TH - Layout plan of the field infrastructure[120]

A main focus of the project is on drilling of two high capacity horizontal ESP wells, drilling horizontal injectors and additional workovers of 41 wells. There are two phases for re-developing the 16th TH, phase 0 and phase 2. Phase 0 will be completed in 2013 whereas phase 2 is going to be finished in 2014/2015. In phase 0 the gross production rate of the Bockfließ Area should be increased by 150 m³/d. Therefore, one support is to drill a high

[120] Tecon Engineering (2013): after consultation with Nusser Heinz; EATP-1 Project Management 1

capacity production well (Bo 204) horizontally. Therefore it is necessary to build a new life oil line into the GOSP Auersthal also in phase 0 (see figure above). Another concern of phase 0 is building a new life oil line from LOESST Ma XV A over LOESST Ma XV B to LOEMST Ma XV. For that, an alternative scenario is planned (see dotted line in figure above). For injection purposes, the four blue marked wells (highlighted in the legend with "Injection Well Phase 0) are converted from production wells to injection wells (Bo 36, Bo 53, Bo 61, Bo 122). Therefore, new formation water lines need to be built in phase 0 (blue dotdashed line in figure above).

To meet the requirements of higher gross rates it is also necessary to upgrade LOEMST Ma IX by replacement of the actuator manifold and re-edify a ball valve manifold. Furthermore, the group lines from LOESST Ma XV A and LOESST Ma XV B into the group line of LOEMST Ma XV are replaced by pipes with a larger diameter. Another life oil line from LOESST Ma IX A into the GOSP Auersthal will be adapted.[121]

Table 19: Bockfließ Area workovers – phase 0

LOEMST/LOESST	Well	Achievements
LOEMST Ma XVI	Bo 80	Pump: ESP; Rate: 250 m^3/d; Power consume: 99 kW
	Bo 96	Pump: ESP; 200 m^3/d; Power consume: 99 kW
	Bo 141	Pump: SRP; 110 m^3/d; Power consume: 26 kW
LOESST Ma IX A	Bo 63	Pump: ESP; Rate: 200 m^3/d; Power consume: 99 kW
	Bo 66	Pump: ESP; Rate: 375 m^3/d; Power consume: 127 kW
	Bo 118	Pump: ESP; Rate: 250 m^3/d; Power consume: 99 kW
LOESST Ma IX C	Bo 68	Pump: ESP; Rate: 375 m^3/d; Power consume: 127 kW
LOEMST Ma IX	Bo 3, Bo 203	Pump: ESP; Rate: 200 m^3/d; Power consume: 99 kW
	Bo 79, Bo 157, Bo 117, Bo 23	Pump: ESP; Rate: 400 m^3/d; Power consume: 127 kW
	Bo 81	Pump: ESP; Rate: 375 m^3/d; Power consume: 127 kW
	Bo 24	Pump: ESP; Rate: 250 m^3/d; Power consume: 99 kW
	Bo 202	Pump: SRP; Rate: 100 m^3/d; Power consume: 26 kW

[121] After consultation with Pschernig Gernot; EATP-1 Project Management 1

In phase 2, the high capacity production well Bo 205 will be drilled horizontally. Therefore, a new life oil line to the GOSP Auersthal will be built (see red line from Bo 205 to GOSP). Another subject of phase 2 is drilling of 2 horizontal injection wells (Bo 206 & Bo 207). To tie both wells into the formation water system, it is necessary to build new formation water lines from both wells into the existing system. To provide solid injection in future, there are 8 other wells that will be converted from producer to injectors (Bo 11, Bo 14, Bo 34, Bo 40, Bo 82, Bo 114, Ma F261, Ma F253). To handle the extra rates due to additional injectors, additional formation water lines need to be built in phase 2 (red dotdashed line in Figure 33).[122]

Due to higher gross rates in phase 2 it is necessary to replace four actuator manifolds by a ball valve manifold in LOEMST Ma XV. Another issue of phase 2 is to reconstruct the valve boxes of Ma XVI and MA IX.

Table 20: Bockfließ Area workovers: phase 2

LOEMST/LOESST	Well	Achievements
LOEMST Ma XV	Bo 48, Bo 111, Bo 121	Pump: ESP; Rate: 250 m³/d; Power consume: 99 kW
	Bo 75, Bo 78, Bo 120, Bo 152	Pump: ESP; Rate: 350 m³/d; Power consume: 127 kW
	Bo 45	Pump: ESP; Rate: 500 m³/d; Power consume: 184 kW
	Bo 54	Pump: SRP; Rate: 150 m³/d; Power consume: 34 kW
	Bo 104	Pump: SRP; Rate: 20 m³/d; Power consume: 26 kW
	Bo 112	Pump: SRP; Rate: 150 m³/d; Power consume: 32 kW
LOEMST Ma XVI	Bo 5	Pump: ESP; Rate: 375 m³/d; Power consume: 127 kW
	Bo 201	Pump: SRP; Rate: 100 m³/d; Power consume: 45 kW
LOEMST Ma IX	Bo 11	Conversion into injection well
	Bo 35, Bo 37	Pump: ESP; Rate: 250 m³/d; Power consume: 99 kW
	Bo 43	Pump: ESP; Rate: 220 m³/d; Power consume: 99 kW
	Bo 85	Pump: ESP; Rate: 375 m³/d; Power consume: 127 kW

122 After consultation with Nusser Heinz; EATP-1 Project Management 1

5.3.2 GOSP Auersthal conversion

Because of an increase in gross production, a conversion of the gas and oil separation plant in Auersthal is unavoidable. The oil and gas separation plant has already reached its limit in Auersthal. Currently, the total gross rate through amounts to ~450 m³/h. That amount is composed of 425 m³/h formation water and 24 t/h oil (~27 m³/h).

Therefore, the oil, gas and water mix enters the oil and gas separation plant and flows through one of five separators. After running through that stage, gas is led to the compressor station in Auerstahl and the oil is led into two tanks, each with a capacity of 1.000 m³. Afterwards the oil is piped to the tankfarm. The separated water is either piped to the water treatment plant to Schönkirchen or it is directly led to the water injection ring (max. 190 m³/h). Before the water is brought to the water injection ring it has to be treated in a 3.000 m³ tank and subsequently in a PPS (parallel plate separator).

When the gross production will be increased, about 800 m³/h will flow through GOSP Auersthal. Therefore, some renewals have to be implemented. At the entrance of the separation plant, additional separators and slug catchers have to be installed. For water processing, additional hydrocyclones or tanks and PPSs are planned.

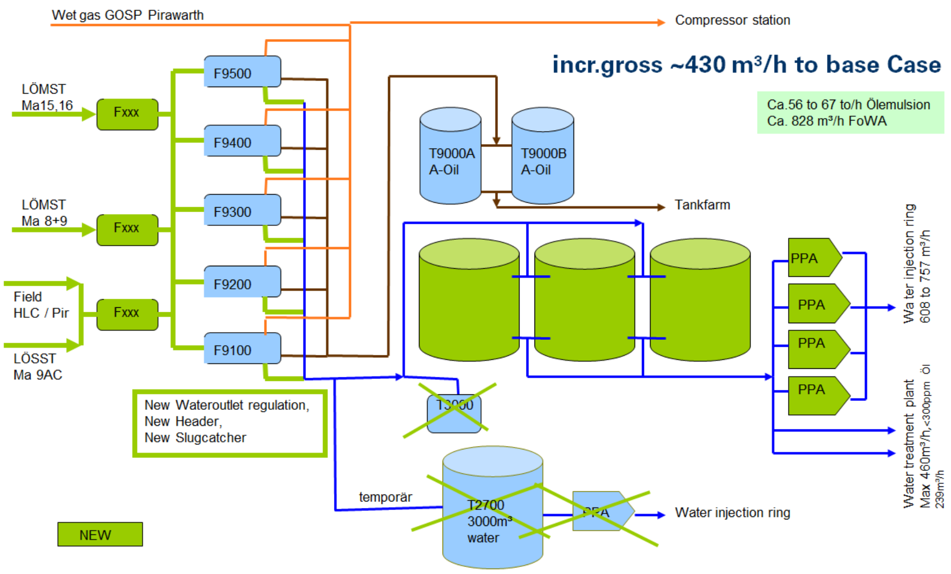

Figure 34: Upgrade of GOSP Auersthal[123]

5.3.3 Water treatment – Bockfließ Area

The program management of OMV Austria initializes a new water processing concept inside of GOSP Auersthal in the course of the re-development of the 16th TH. Due to higher gross production rates as a consequence of the MORE program, a much higher water rate will be expected (see Figure 35) and because of the fact that the facilities for treating for-

[123] After consultation with Nusser Heinz; EATP-1 Project Management 1

mation water already reached the capacity limit, water management will be a key issue in the wake of re-development of the 16th TH.

If water is cited within this thesis, the term "produced water" will be meant. The pore space in underground rocks is commonly filled with a mixture of water and hydrocarbons (liquid and gas). Reservoir rocks usually contain both. The water can flow from above or below the hydrocarbon bearing zone or it can be re-injected and including production additives. This is also referred to as formation water and it is produced if the reservoir is depleted and the fluid mix is brought to the surface.[124]

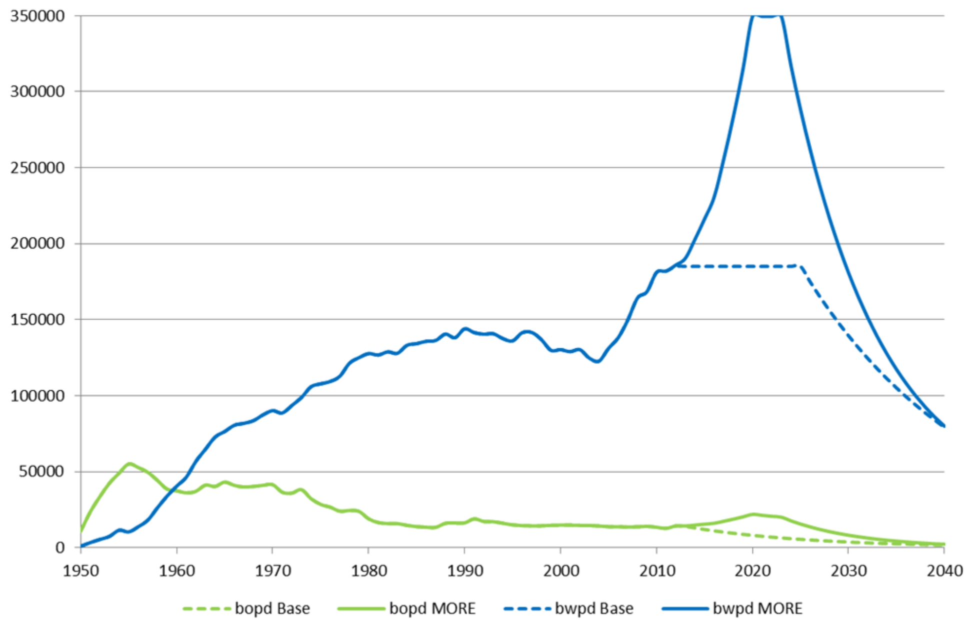

Figure 35: Additional water production in the course of the MORE program[125]

The composition, chemical and physical properties depend strongly on the individual hydrocarbons in place, geological structure and geographical situations. The lion's share of produced water is water. Slight components are organic and inorganic components including dissolved hydrocarbons, organic acids, phenols, traces of production additives, solids and low radioactive elements. The composition of the produced water changes over the duration of production because more and more water is injected to maintain reservoir pressure.[126]

During the production of hydrocarbons, produced water is an unpleasant concomitant, especially in mature oilfields. Shell has stated some oilfields where a production water increase of 350 % from 1990 – 2005 was recognized.[127]

[124] C.f. Veil, J. A. et al. (2004), p. 1

[125] C.f. RD 16. TH Bo Area GATE 2 Presentation (2012), p. 34; after consultation with Nusser Heinz; EATP-1 Project Management 1

[126] C.f. Mofarrah, A. (2008), p. 8

[127] C.f. Khatib, Z.; Verbeek, P. (2003), p. 27

Due to the increase of water requirement over the last years, an increase of water expenditures is involved. The lion's share of these costs is given by costs for re-injection and treatment.[128]

There are two main thoughts about the redesign of water processing in the Bockfließ Area. One is to treat the formation water with hydrocyclones. The other option is water processing with tanks and parallel plate separator. There are several considerations in selecting either hydrocyclones or the options with tanks and parallel plate separators:

Table 21: Hydrocyclones vs. Tanks & parallel plate separator[129]

Hydrocyclones	Tanks & parallel plate separator
Theoretical retention time ~10 min	Theoretical retention time ~60-65 min
Droplets >10µm are suitable for separation; Separation by means of gravity and centrifugal force principle	Increased process certitude due to two-stage treatment; Separation by means of gravity
Smaller footprint	Large footprint compared to hydrocyclones
Incremental scalable (on and off switching of cyclone packages)	Tank is designed for maximum flow-rate
~16 MM EUR acquisition costs	~21 MM EUR acquisition costs[130]

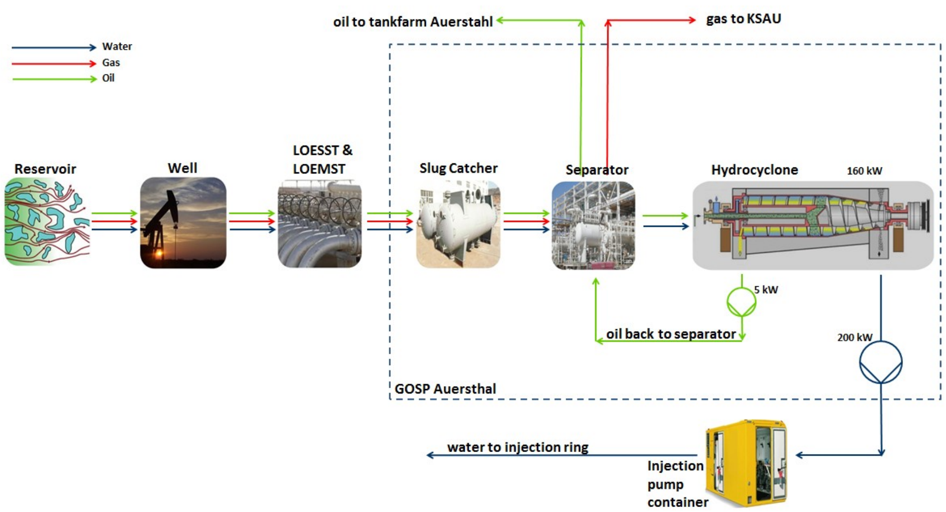

Figure 36: Schematic of GOSP Auersthal with hydrocyclones[131]

For planning the OPEX of the hydrocyclone case, it must be know that three hydrocyclones and associated equipment will be installed. Therefore, two hydrocyclones in

[128] C.f. Hill, F. et al. (2012), p.2

[129] After consultation with Fili Gregor; EATP-0 Project Office

[130] N.B. Cost estimation of VTU engineering (27.09.2012); after consultation with Fili Gregor; EATP-0 Project Office

[131] After consultation with Fili Gregor; EATP-0 Project Office

process and one that acts as a cushion will be necessary. Furthermore, one oil withdrawal pump and two ring injection pumps (pumps that bring the water from the processing site to the injection ring) in operation and one that acts again as a cushion are planned.

Each of the hydrocyclones has a motor power of 160 kW, the oil withdrawal pump has 5 kW and the motor power of each of the ring injection pumps is 200 kW. Costs for electrical power are assed with 9 cent/kWh.

For the power cost calculation of hydrocyclones, a runtime of 365 d/yr, 24 h/d and a charge rate of 0,09 EUR/kWh is assumed.

Table 22: Total Power for hydrocyclones

Hydrocyclones	Quantity	Power [kW/Unit]	Total Power [kW]
Hydrocyclones	2	160	320
Oil withdrawal pump from Hydrocyclone	1	5	5
Ring injection pump	2	200	400
Total Power [kW]			**725**

For the above mentioned assumptions, total power costs of **0,57 MM EUR/yr** are calculated.

To operate the hydrocyclones, a single person is necessary. Assuming a total working hours of 1.860 per year and an hourly rate of 120 EUR for one internal service operator, total operating costs are determined with **0,22 MM EUR/yr**.

Cleaning and maintenance is assumed to be 339 h/yr. Total cleaning and maintenance costs of **0,027 MM EUR/yr** is a result of hourly rate of 79 EUR for one worker.

Assuming a stable price for electric current of 9 cent/kWh and stable costs for internal labor (120 EUR/h) and external labor (79 EUR/h) total **OPEX** of **5,05 MM EUR** is calculated over the next 10 years with a discount rate of 10 %. Considering a discount rate of 15 %, total **OPEX** of **4,12 MM EUR** is calculated over the next 10 year.

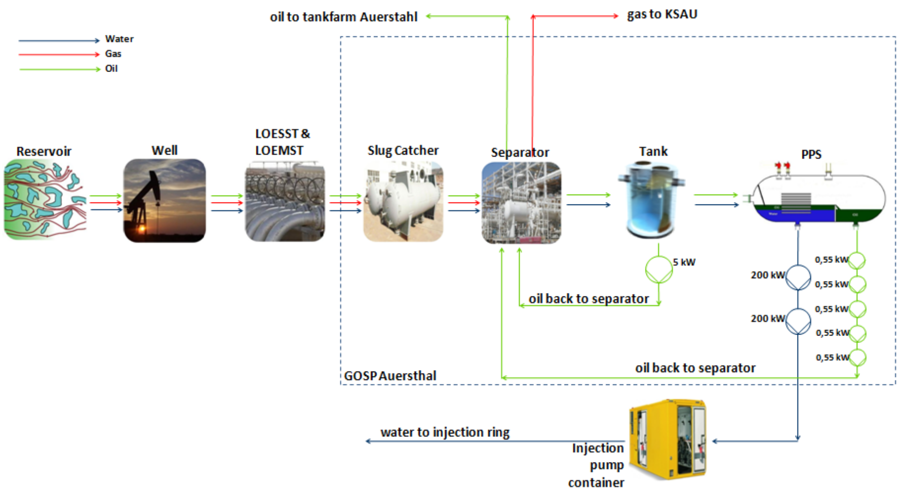

Figure 37: Schematic of GOSP Auersthal with tank & PPS[132]

[132] After consultation with Fili Gregor; EATP-0 Project Office

The principles of Figure 36 and Figure 37 are quite the same. In case of the former hydrocyclones are used with extra energy consumption of two units. In the latter case tanks and PPSs are used for separation purposes. The energy requirements are only those of two ring injection pumps and oil withdrawal pumps from the tank and PPS (see next table).

Table 23: Total Power for tank & PPSs

Tank + PPSs	Quantity	Power [kW/Unit]	Total Power [kW]
Oil withdrawal pump from Tank	1	5	5
Oil withdrawal pump from PPAs	5	0,6	3
Ring injection pump	2	200	400
Total Power [kW]			**408**

Total power costs per year are calculated based on total power of 408 kW and constant power costs of 0,09 EUR/kWh with **0,32 MM EUR/yr**.

For cleaning & maintenance purposes it is assumed to have 340 h internal personnel and 527 h external personnel with external personnel rates of 79 EUR/h and internal personnel rates of 120 EUR/h. Total cleaning & maintenance costs are therefore calculated with **0,082 MM EUR/yr**.

Assuming a stable price for electric current of 9 cent/kWh and stable costs for internal labor (120 EUR/h) and external labor (79 EUR/h) total **OPEX** of **2,48 MM EUR** is calculated over the next 10 years with a discount rate of 10%. **OPEX** is calculated with **2,03 MM EUR** over the next 10 years with a discount rate of 15%.

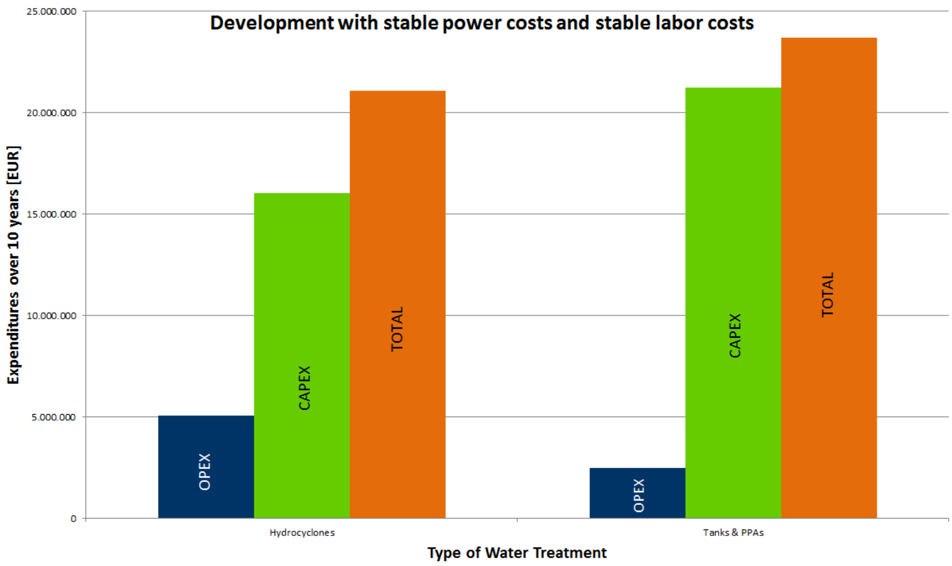

Figure 38: Alternatives comparison – stable power and cleaning & maintenance costs

Both calculations are based on the assumptions of stable energy costs and stable labor costs over the next 10 years. CAPEX shown in Figure 38 result from a cost estimation with an actual amount of ~16 MM EUR for Hydrocyclones and ~21,2 MM EUR for the alternative with Tanks & PPSs.[133]

In the following, a scenario was generated by assuming increasing power costs of 3% per year and increasing labor costs 2% per year springing from the costs of 2013. CAPEX will remain the same as shown in Figure 38.

Table 24: Increasing Power Costs – Hydrocyclones vs. Tanks & PPSs

Hyrdocyclone Power Costs			Tanks & PPSs Power Costs		
Year	Power Costs [kWh]	Power Costs [EUR/yr]	Year	Power Costs [kWh]	Power Costs [EUR/yr]
2014	0,090	571.590	2014	0,090	321.667
2015	0,093	588.738	2015	0,093	331.317
2016	0,095	606.400	2016	0,095	341.257
2017	0,098	624.592	2017	0,098	351.494
2018	0,101	643.330	2018	0,101	362.039
2019	0,104	662.629	2019	0,104	372.900
2020	0,107	682.508	2020	0,107	384.087
2021	0,111	702.984	2021	0,111	395.610
2022	0,114	724.073	2022	0,114	407.478
2023	0,117	745.795	2023	0,117	419.703
TOTAL over 10 yrs.		**3.934.679**	**TOTAL over 10 yrs.**		**2.214.275**

Power Costs [EUR/yr] in the table above are calculated by multiplying the actual power costs [kWh] with the total power of the hydrocyclone (725 kW) or tanks & PPSs (408 kW) and the total hours of operation per day. Therefore, a full time operation of 8.760 hours per year is assumed. The total power costs over the next 10 years are **3,93 MM EUR** for hydrocyclones and **2,21 MM EUR** for tanks & PPSs with a discount rate of 10%. Considering a discount rate of 15%, power costs are calculated with **3,18 MM EUR** for hydrocyclones and **1,79 MM EUR** for tanks and PPSs.

Table 25: Increasing Cleaning & Maintenance Costs – Hydrocyclones vs. Tanks & PPSs

Hyrdocyclone Cleaning & Maintenance				Tanks & PPSs Cleaning & Maintenance			
Year	Labor internal [EUR/h]	Labor external [EUR/h]	Cleaning & Maintenance Costs [EUR/yr]	Year	Labor internal [EUR/h]	Labor extern [EUR/h]	Cleaning & Maintenance Costs [EUR/yr]
2014	120,000	79,000	249.981	2014	120,000	79,000	82.433
2015	122,400	80,580	254.981	2015	122,400	80,580	84.082
2016	124,848	82,192	260.080	2016	124,848	82,192	85.763
2017	127,345	83,835	265.282	2017	127,345	83,835	87.479
2018	129,892	85,512	270.587	2018	129,892	85,512	89.228
2019	132,490	87,222	275.999	2019	132,490	87,222	91.013
2020	135,139	88,967	281.519	2020	135,139	88,967	92.833
2021	137,842	90,746	287.150	2021	137,842	90,746	94.690
2022	140,599	92,561	292.893	2022	140,599	92,561	96.583
2023	143,411	94,412	298.750	2023	143,411	94,412	98.515
TOTAL over 10 yrs.			**1.656.202**	**TOTAL over 10 yrs.**			**546.144**

[133] N.B. Cost estimation of VTU engineering (27.09.2012); after consultation with Fili Gregor; EATP-0 Project Office

The time for internal cleaning & maintenance of hydrocyclones is assumed to be 1.860 h and for external cleaning & maintenance it is supposed to be 339 h. The time for internal cleaning & maintenance of tanks & PPSs is assumed with 340 h and that of external cleaning & maintenance should be 527 h.[134] Total costs per year [EUR/yr] result by multiplying these hours with the hourly rates of labor (internal and external). Total costs for cleaning & maintenance over the next 10 years with a discount rate of 10% amount for **1,66 MM EUR** in the case of hydrocyclones and **0,55 MM EUR** in the case of tanks & PPSs. Considering a discount rate of 15%, total cleaning & maintenance costs amount for hydrocyclone **1,34 MM EUR** and **0,44 MM EUR** for tanks & PPSs.

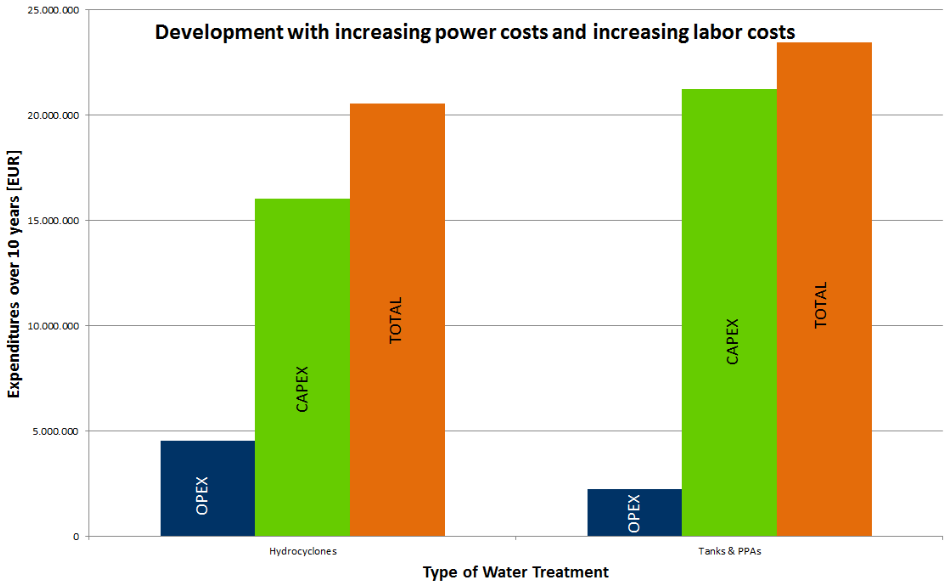

Figure 39: Alternatives comparison – increasing power and cleaning & maintenance costs

Increasing energy costs of 3% per year and increasing labor costs of 2% per year do not seriously affect total costs over 10 years. However, it becomes apparent that increasing energy costs influence total costs of hydrocyclones by an infinite deal more than the alternative with tanks & PPSs. Comparing both calculations, stable and increasing costs, OPEX

5.3.4 Injection system

In total 13 pump containers are necessary to inject the processed formation water back into the subsurface. Each of the existing and planned injection wells has an injection pump container which transfers the injection water to the well and increases the pressure so that the water can be injected. 7 containers are fitted with a capacity of 1.000 m³/d. The other 6 container are fitted with a capacity of 1.500 m³/d. There will be two new horizontally drilled injection wells and each with a capacity of 4.500 m³/d. Therefore, each of the new drilled injection wells will be equipped with 3 pump containers with a capacity of the last-named.

[134] After consultation with Fili Gregor; EATP-0 Project Office

An injection pump container is a unit that consist of a high pressure pumping set, a lubrication system, a switchboard, a cable system and the container itself. The container is split into a hydraulic room and an electronic room.

Costs are caused by the high pressure pump set that conveys the water into the formation. Therefore an enormous energy input is necessary. The energy consumption data are based on the quotation of Sonnek Engineering.[135]

Total power costs are then calculated over 10 years. In Table 26, total power costs are calculated with **6,43 MM EUR** with a discount rate of 10%. Considering a discount rate of 15%, total power costs over 10 years amount for **5,20 MM EUR**. The calculation was done on the assumption of an energy cost increase of 3% per year.

Table 26: Power costs of injection pump container

Injection pump container	Quantity	Power [kW/Unit]	Total Power [kW]	Total Power Costs [EUR/yr]
1.000 m³/d	7	75	525	413.910
1.500 m³/d	6	110	660	520.344
Total power costs over 10 yrs. [EUR]			**1.185**	**6.431.165**

By summing up the power costs for the injection pump containers and the OPEX calculated above, total OPEX can be determined for the injection system of the Bockfließ Area.

Table 27: Total OPEX of the injection system @ 10% discount rate

	OPEX Hydrocyclones [EUR]	OPEX Tanks & PPSs [EUR]
Power Costs over 10 yrs	3.934.679	2.214.275
Cleaning & Maintenance Costs over 10 years	1.656.202	546.144
Injection Pump Container Power Costs	6.431.165	6.431.165
TOTAL OPEX over 10 years	**12.022.046**	**9.191.584**

Table 28: Total OPEX of the injection system @ 15% discount rate

	OPEX Hydrocyclones [EUR]	OPEX Tanks & PPSs [EUR]
Power Costs over 10 yrs	3.180.919	1.790.090
Cleaning & Maintenance Costs over 10 years	1.343.519	443.035
Injection Pump Container Power Costs	5.199.158	5.199.158
TOTAL OPEX over 10 years	**9.723.597**	**7.432.283**

Table 27 and 28 are calculated with the assumption of increasing power and cleaning & maintenance costs.

The necessity of water management in the Bockfließ Area is shown in Figure 40. The right bar from the old water treatment system displays the highest amount of water treatment costs. This can be explained due to the long transport route from the Bockfließ Area to the water treatment plant in Schönkirchen. The costs will be reduced by treating the formation

[135] N.B. Quotation of pump injection container (21.08.2012); after consultation with Fili Gregor; EATP-0 Project Office

water either with hydrocyclones or tanks & PPSs. The fact that hydrocyclones have higher costs for water treatment than tanks & PPSs can be explained due to higher energy consumption of hydrocyclones.

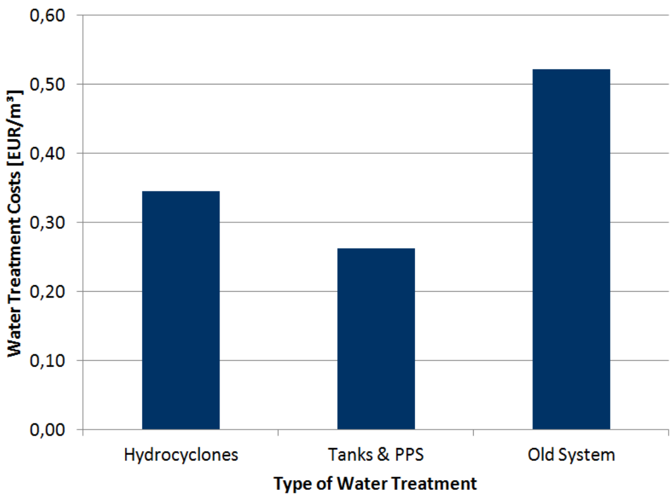

Figure 40: Water treatment cost for the individual scenarios

5.4 Total OPEX forecast – Bockfließ Area

For calculating the operating costs of the Bockfließ area, three scenarios were elaborated and compared with each other. In the previous section, water handling costs for two different cases were calculated. These costs are used in this section to find out the total OPEX per m^3 oil in the Bockfließ area.

The Program Management defined a list of wells that should be revised by increasing the gross rate. This should be most often accomplished by an exchange of sucker rod pumps by electric submersible pumps.

For the calculation, it was important to find out the water treatment costs, energy costs and well intervention costs. The water treatment costs are defined in the previous section. Energy costs and well intervention costs are rate dependent. Costs for well interventions were determined by means of the Information Management in Gänserndorf. Well interventions depend on the MTBF. These values were determined empirically by gathering all well interventions since the year 2000. Values for energy consumption were especially measured for this thesis.

An extract of the OPEX calculation from the Bockfließ Area can be seen in the following Table 29. In this method of calculation, data only have to be entered in the input lines of gross rate and water cut. The rest is done automatically.

The energy consumption is dependent on the producing rate and on the type of pump. OMV has to pay a fixed charge rate of 0,09 EUR/kWh. For energy consumption, several ranges were defined based on data from the Information Management. The same procedure was done for the MTBF to calculate the costs for well interventions. A summary of the rate dependency is shown in Table 30.

For the last three rate ranges, it was not possible to elaborate values for MTBF or power consumption because of a lack of data. Only values for ESP power consumption could be determined because of an ESP pilot project.

Table 29: Extract of the OPEX calculation in the Bockfließ Area

Pump Type	ESP	ESP	ESP	ESP	SRP	ESP
WELL No.	BO_003	BO_005	BO_006A	BO_011	BO_014	BO_023
ENERGY CONSUMPTION [kW]	45,00	100,00	75,00	100,00	8,00	125,00
GROSS RATE [m³/d]	200,00	375,00	250,00	375,00	74,38	400,00
WATER CUT [%]	96,15	98,16	94,34	98,40	98,20	97,68
OIL RATE [m³/d]	7,70	6,90	14,15	6,00	1,34	9,28
OIL RATE [bbl/d]	48,43	43,40	89,00	37,74	8,42	58,37
WATER RATE [m³/d]	192,30	368,10	235,85	369,00	73,04	390,72
PORTION OF TOTAL WATER RATE	0,0126	0,0242	0,0155	0,0243	0,0048	0,0257
ENERGY COSTS [EUR/year]	35.478	78.840	59.130	78.840	6.307	98.550
OIL TREATMENT COSTS [EUR/year]	7.439	6.666	13.670	5.797	1.293	8.965
WATER TREATMENT COSTS [EUR/year]	22.208	42.510	27.237	42.613	8.435	45.122
MTBF [days]	860	1.070	1.070	1.070	1.040	1.070
WI COSTS [EUR/year]	71.260	57.274	57.274	57.274	17.302	57.274
OPEX [EUR/year]	**136.384**	**185.290**	**157.311**	**184.524**	**33.338**	**209.911**
OPEX [EUR/m³]	**48,53**	**73,57**	**30,46**	**84,26**	**68,22**	**61,97**
OPEX [EUR/bbl]	**7,71**	**11,70**	**4,84**	**13,40**	**10,85**	**9,85**
OPEX Savings [EUR/bbl]	**0,64**	**1,37**	**0,43**	**1,58**	**1,40**	**1,08**

The oil treatment costs were calculated on the basis of a charge rate of 2,65 EUR/m³. This value could be easily found out through dividing the total costs incurred in the tankfarm in Auersthal in the year 2012 by the total oil production of 2012. Average well intervention costs were used for both pumps. These costs were gathered from SAP since the year 2000. For ESPs, an average value of 170.000 EUR/WI and for SRPs, an average value of 53.000 EUR/WI was used. This big difference can be explained due to higher costs of ESPs compared to SRPs.

Table 30: Rate dependency of the power consumtion and MTBF

Rate [m³/d]	MTBF ESP [d]	MTBF SRP [d]	ESP power [kW]	SRP power [kW]
0 - 75	660	1040	30	8
76 - 125	790	1145	35	11
126 - 175	540	740	40	17
176 - 225	860	390	45	22
225 - 275	1070	190	75	30
276 - 380			100	
381 - 450			125	
>450			152	

A calculation, as it is shown in Table 29, was done for three cases:

- OPEX with hydrocyclone water treatment
- OPEX with tanks & PPSs water treatment
- OPEX of the old system

The difference in total OPEX between the water treatment of the old system and the new systems is substantial and can be seen in Figure 41. The disparity can be explained by the transportation of the water. In the old system, the water is transported over several kilometers from the Bockfließ area to the water treatment plant in Schönkirchen. Due to this transportation, costs are much higher than in the case of treating the costs locally with hydrocyclones or tanks & PPSs.

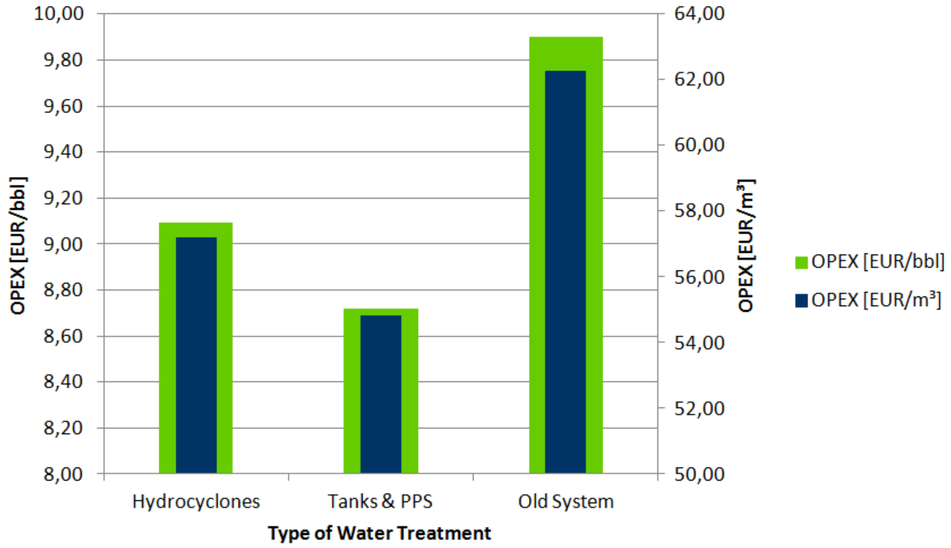

Figure 41: OPEX for Water Treatment Scenarios

The cost difference between hydrocyclones and tanks & PPSs as shown in Figure 41 can be interpreted due to the higher energy consumption of hydrocyclones. Total OPEX are calculated with 57,17 EUR/m³ (9,09 EUR/bbl) if water treatment is done with hydrocyclones. In the case of water treatment with tanks & PPSs, total OPEX amount to 54,85 EUR/m³ (8,72 EUR/bbl). Considering the old water treatment system where the formation water is treated in the water treatment plant Schönkirchen, total OPEX are calculated with 62,27 EUR/m³ (9,90 EUR/bbl).

The total OPEX are composed of four cost categories. These are costs for energy, oil treatment, water treatment and well interventions. In the following, the cost composition of the individual cases is given.

Energy Costs

Energy costs are dependent on the type of pump, whether ESP or SRP, the desired rate, the costs for power (EUR/kWh) and consequently the power consumption of the pump.

Oil Treatment Costs

Oil treatment costs were calculated based on a charge rate of 2012. Thereby, the costs from two cost centres were taken into consideration to determine the costs in EUR/m³ oil. The sum of both cost centres was divided by the total oil production in 2012 resulting in a charge rate of 2,65 EUR/m³.

Water Treatment Costs

Water treatment costs were determined based on the calculations in chapter 5.3.3. Thereby three scenarios were investigated. The costs for the injection system are also included in that fragmentation.

Well Intervention Costs

Well intervention costs are dependent on the type of pump, whether ESP or SRP, the desired rate and consequently the MTBF. For ESPs, well intervention costs are assumed to be 170.000 EUR and for SRPs, well intervention costs are assumed to be 53.000 EUR.

Cost for energy, oil treatment and well interventions will not change in the three cases described in the following figures. Only water treatment costs will change because of the different treatment methods.

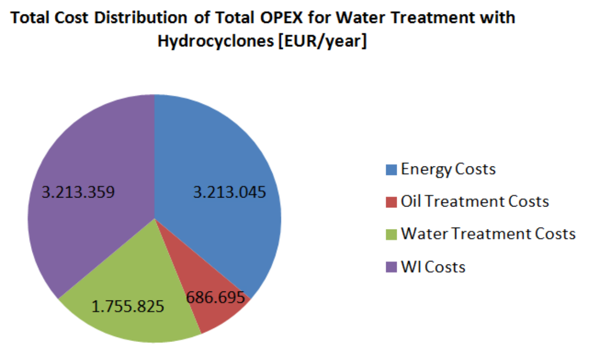

Figure 42: OPEX composition in the case of hydrocyclones water treatment

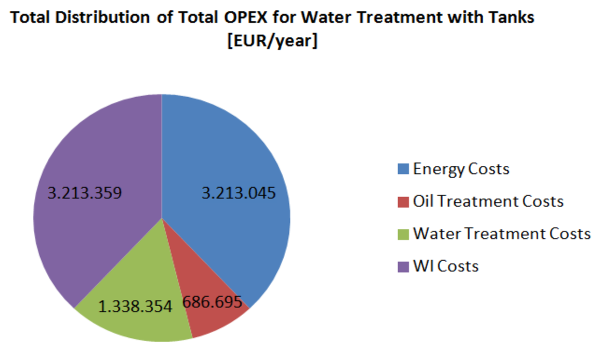

Figure 43: OPEX composition in the case of tanks & PPSs water treatment

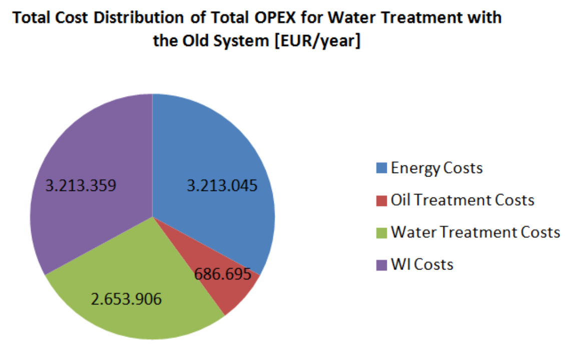

Figure 44: OPEX composition in the case of the old water treatment system

The costs improvement in water treatment can be seen in the figures above. Water treatment amounts to 27,2 % of total OPEX in the case of the old system. Through improvements by hydrocyclones or tanks & PPSs costs and local injection, water treatment costs can be reduced to 19,8% of total OPEX in the case of hydrocyclones and 15,8% in the case of tanks & PPSs. The total calculation of the OPEX for the Bockfließ Area can be seen in the Appendix F.

6 Findings & Conclusion

The first main step of the thesis was to review the split of OPEX within OMV Austria E&P. This was visualized by creating hierarchically structures. A breakdown of costs was stated and individual examples were presented to support a better understanding. After splitting the operating costs into its sub-cost categories, a cost distribution was created to show the weighing of the OPEX components based on the costs of 2012 of the Matzen oilfield. The results clearly demonstrated that service costs, which include all the well interventions represent the lion's share with ~57% of the total OPEX. Additionally a split of production costs and lifting costs into its components was constituted, to allow the identification and control of the main cost drivers. Beside this a description and the interaction of the individual cost centers in the Matzen oilfield were presented. Therefore, a graphical description was created to visually demonstrate the connections within the total cost center system.

In the practical section of the thesis, life-cycle-costs of ESPs and SRPs were determined to assess the total cost of facility ownership over a pre-defined lifecycle of 25 years. Therefore, the parameters production rate, power consumption and Mean Time Between Failure (MTBF) were examined to get the total life-cycle-costs for both pumps. The results showed that SRPs deliver better results than ESPs for lower production rates. With increasing production rate, the costs for SRPs rise stronger than the costs for ESPs. This can be explained due to the fact that ESPs operate more reliable at higher production rates than SRPs, which rather means that by higher production rates the MTBF for ESPs is higher than this for SRPs.

The results showed for rates up to 200 m^3/d very reasonable values for SRPs. At a rate of 225 m^3/d costs for SRPs exceed the costs for ESPs, so that by higher rates the usage of ESPs is economically beneficial.

Another task of the thesis was to generate the total OPEX of the Bockfließ Area on the basis of individual wells. The total OPEX in this case include water treatment costs, energy costs to drive the pumps, oil treatment costs and well intervention costs. For calculating the water treatment costs, three different scenarios were elaborated. These were water treatment with hydrocyclones, tanks & PPSs and the existing system. For all these methods, power costs and maintenance costs were taken into consideration. Therefore, a stable price case and an increasing price case were calculated for both, power and maintenance costs. This was performed in order to verify the sensitivity of each water treatment system towards cost increases. Results showed that a power cost increase would have more impact on hydrocyclones than on tanks & PPSs. That can be easily explained because of the higher energy consumption of hydrocyclones.

After calculating the costs for the different water treatment methods, the cost for the re-injection system of the formation water was calculated. On that account, 13 pumps are used to inject the treated formation water back into the subsurface. Power costs were determined based on 7 pumps with a capacity of 1.000 m^3/d and 6 pumps with a capacity of 1.500 m^3/d.

By adding up the costs of the different water treatment systems with the costs of the pump injection systems, three different costs were obtained. Total costs for water treatment account 9,09 EUR/m^3 in case of hydrocyclones, 8,72 EUR/m^3 for tanks and PPSs and 9,90 EUR/m^3 for the already existing water treatment system.

After the calculation of water treatment costs, costs for well interventions were determined. Therefore, the reliability of the pumps was the critical factor which had to be found out. MTBF were defined based on the type of pump to be used and based on the desired production rate. Costs per well interventions were figured out for SRPs with 53.000 EUR and for ESPs with 170.000 EUR. With the MTBF, costs for well interventions could be annualized.

Another cost intensive issue was the power cost. Therefore, pre-defined wells were measured by the Electrical Engineering Department in Gänserndorf. As a consequence, ranges of production rates were defined and power consumption could be linked to each range.

Oil treatment costs were based on the costs of 2012. Thereby, the related costs centers were summed up and divided by the total oil production of 2012. The charge rate of oil processing was calculated by that approach with 2,65 EUR/m³ oil.

Finally it can be clearly stated that due to the desired higher gross production rate, a new water treatment system will be indispensable, not only from an economically point of view but also due to the fact that the capacity limit of the existing system is already reached. For the case of hydrocyclones, total OPEX are determined with 57,20 EUR/m³ (9,09 EUR/bbl), for the case of tanks & PPSs, OPEX amount for 54,84 EUR/m³ (8,72 EUR/bbl) and for the existing system, the OPEX are calculated with 62,26 EUR/m³ (9,90 EUR/bbl).

The option with tanks & PPSs might be the more inexpensive alternative but there are a variety of arguments that make the water treatment method with hydrocyclones very attractive. One reason therefore is the lower acquisition cost for hydrocyclones. These account for 16 MM EUR in the case of hydrocyclones and 21 MM EUR for tanks. Hydrocyclones have a very stable operation and are incremental scalable whereas tanks are designed for a maximum flow rate. Another major aspect is the smaller size compared to that of tanks resulting in a lower floor space for hydrocyclones.

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Appendix A – Reserves Classification

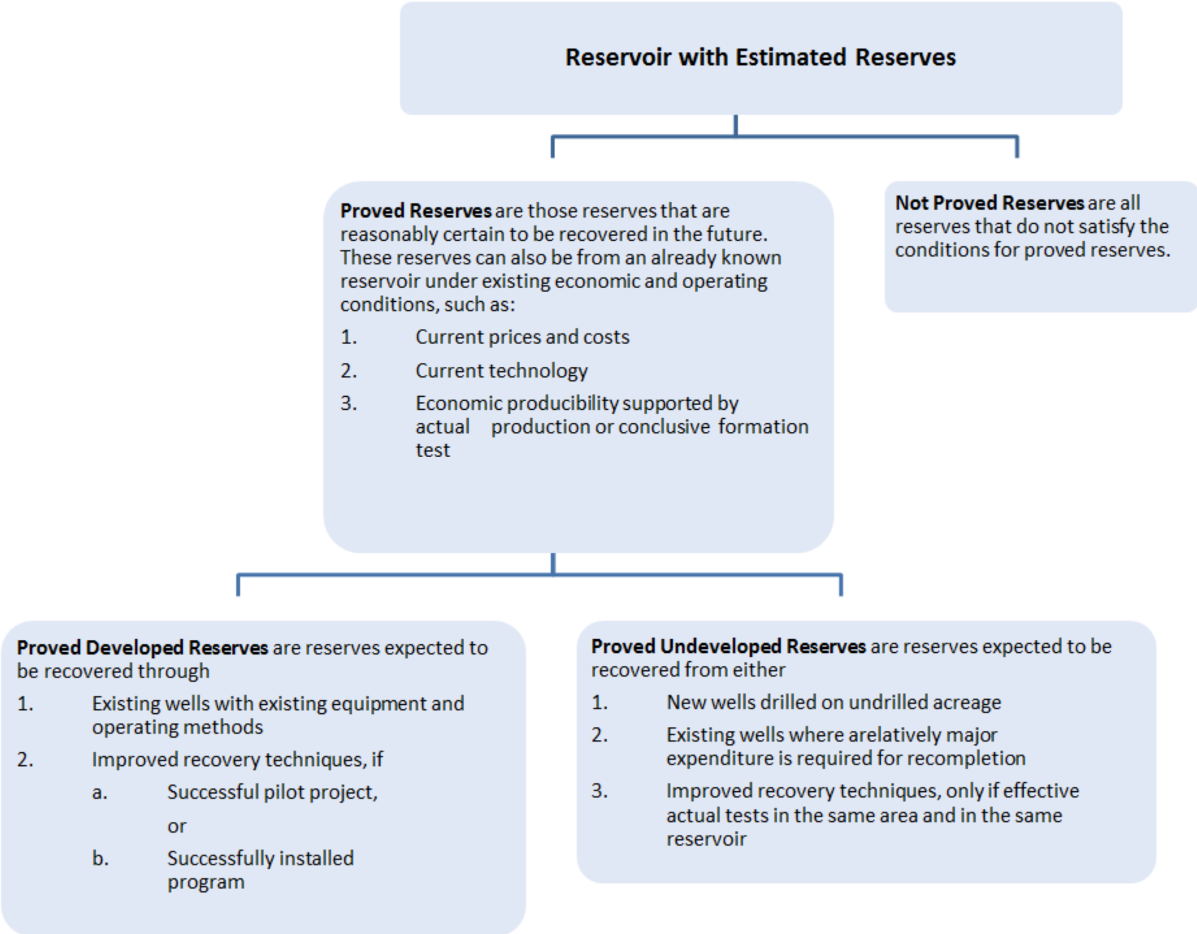


Figure 45: Classification of Reserves[136]

[136] C.f. Gallun, R., et al., (2001), p. 32

Appendix B – SAP Cost Structure

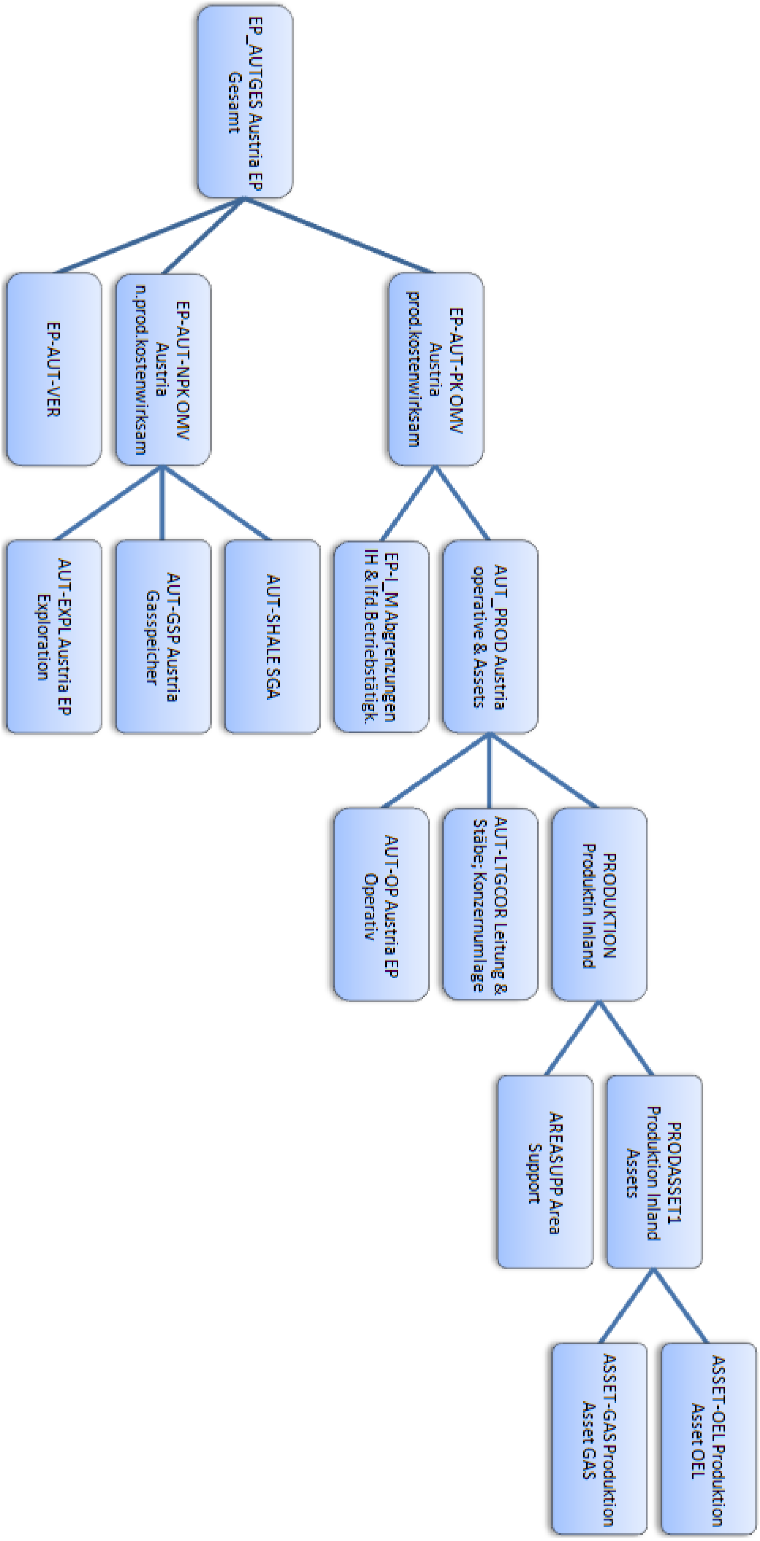
Table 31: Profit Center Hierarchy of OMV E&P AUT[137]

```
EP-AUT              2100 Austria Exploration & Produktion
 |
 |--🗀 EP-AUSCOR        Konzernumlagen
 |    |
 |    |--1900        Corporate EP Austria
 |
 |--🗀 EP-AUTGES        Austria EP Gesamt
      |
      |--🗀 AUSTRIA-1       Austria EP 1
      |    |
      |    |--🗀 AUS-OVER        Austria EP Overhead
      |    |    |
      |    |    |--1170       Austria EP Overhead
      |    |
      |    |--🗀 AUT-OPAS        Austria operativ & Assets
      |    |    |
      |    |    |--🗀 PRODUKTION      Produktion Inland
      |    |    |    |
      |    |    |    |--🗀 PRODASSET1      Produktion Inland Assets
      |    |    |    |    |
      |    |    |    |    |--🗀 ASSET-OEL       Produktion Asset OEL
      |    |    |    |    |    |
      |    |    |    |    |    |--1101       Area 1 - Nord
      |    |    |    |    |    |--1102       Area 2 - MAOEL
      |    |    |    |    |    |--1104       Area 4 - P/H
      |    |    |    |    |    |--1115       Area 5 - SüdOEL
      |    |    |    |    |
      |    |    |    |    |--🗀 ASSET-GAS       Produktion Asset GAS
      |    |    |    |         |
      |    |    |    |         |--1103       Area 3 - H2S S/R
      |    |    |    |         |--1105       Area 5 - SüdGAS
      |    |    |    |         |--1106       Area 6 - HOE
      |    |    |    |         |--1107       Area 7 - West
      |    |    |    |         |--1112       Area 2 - MAGAS
      |    |    |    |         |--1113       Area 3 - H2S STR
      |    |    |    |         |--1114       Area 4 - P/HGAS
      |    |    |    |
      |    |    |    |--🗀 AREASUPP        Area Support
      |    |    |         |
      |    |    |         |--1110       Area 0 - AllgemeinOEL
      |    |    |         |--1119       Area 0 - Allgemein GAS
      |    |    |         |--1180       Energie
```

[137] N.B. Actual display of SAP profit center structure

```
|    |    |
|    |    |--🗀 AUT-EXPL         Austria EP Exploration
|    |    |    |
|    |    |    |--1120       Austria EP Exploration
|    |    |
|    |    |--🗀 AUT-LTG          Leitung & Stäbe
|    |    |    |
|    |    |    |--1130       Leitung und Stäbe
|    |    |
|    |    |--🗀 AUT-OP           Austria EP Operativ
|    |         |
|    |         |--1140       IH
|    |         |--1150       SOB
|    |
|    |--🗀 AUT-GSP          Austria Gasspeicher
|         |
|         |--1111       Area 11 - Speicher
|
|--🗀 AUSTRIA2         Verrechnungs PC
     |
     |--1121       Verr.PC Exploration
     |--1131       Verr.PC Leitung & Stäbe
     |--1141       Verr.PC IH
     |--1151       Verr.PC SOB
     |--1161       Verr.PC Asset ÖL
     |--1171       Verr.PC Asset GAS
     |--1172       Verr.PC GSP
     |--1198       Austria EP-Verrechnung
```

Appendix C – Total Cost Structure of OMV Austria E&P



Appendix D – Cost Center Sequence

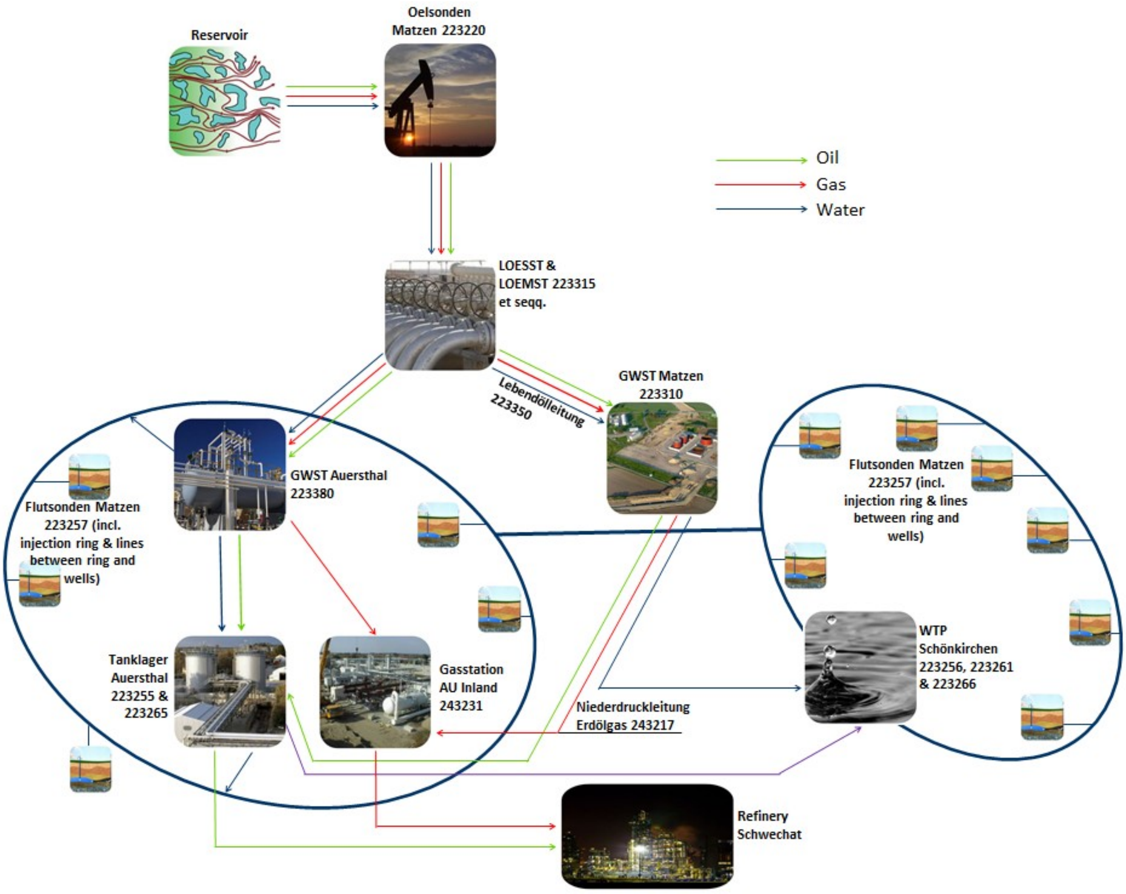


Figure 46: Cost center sequence in the Matzen field[138]

[138] After consultation with the stated cost center controller in the previous pages

Appendix E – Costs for ESP Well Intervention

Table 32: ESP Well Intervention Costs[139]

Bo 31	Activity	Duration Gross [d]	Production [t]	Costs [€]
12.11.2008	Conversion to ESP	818	3.635	85.921,65
08.02.2011	ESP Change + Tubing Change	412	1.437	53.459,42
26.03.2012	ESP Change + Tubing Change			196.191,22
Ma 58	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
23.11.2004	ESP Change	412	1.182	65.664,44
26.04.2006	ESP Change	566	2.920	92.180,35
14.11.2007	ESP Change			92.700,44
Ma 73	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
18.11.2004	Conversion to ESP	754	5.562	90.319,90
14.12.2006	ESP Change	1.415	7.461	42.878,77
04.11.2010	ESP Change + Tubing Change			194.218,45
Bo 292	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
07.12.2006	Conversion to ESP	844	10.188	92.914,54
31.03.2009	ESP Change + Tubing Change	833	7.095	158.942,12
12.07.2011	ESP Change + Tubing Change			170.916,11
Bo 25	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
16.11.2007	Conversion to ESP	1.231	17.533	94.380,99
04.04.2011	ESP Change + Tubing Change			173.233,53
Bo 68	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
10.02.2011	Conversion to ESP	650	6.080	94.822,97
22.11.2012	ESP Change + Tubing Change			187.481,54
Bo 102	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
09.02.2011	Conversion to ESP	628	3.978	122.473,97
29.10.2012	ESP Change + Tubing Change			220.338,21
Ma 67	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
06.11.2007	Conversion to ESP	1.856	10.615	67.558,45
Ma 115	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
13.12.2006	Conversion to ESP	1.737	48.122	83.431,33
16.09.2011	ESP Change + Tubing Change			70.551,80
Ma 166	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
05.12.2006	Conversion to ESP	1.170	11.634	92.914,54
22.02.2010	ESP Change + Tubing Change			158.910,07
Average	**Activity**	**Duration Gross [d]**	**Production [t]**	**Costs [€]**
Conversion to ESP		952		91.691,87
ESP Change + Tubing Change				170.087,01

[139] After consultation with Bohrn Wolfgang; EATS-I Information Management

Appendix F – Total OPEX Calculation

Table 33: OPEX Bockfließ Area – Hydrocyclone Water Treatment

Pump Type	ESP	ESP	ESP	ESP	SRP	ESP
WELL No.	BO_003	BO_005	BO_006A	BO_011	BO_014	BO_023
ENERGY CONSUMPTION [kW]	45,00	100,00	75,00	100,00	8,00	125,00
GROSS RATE [m³/d]	200,00	375,00	250,00	375,00	74,38	400,00
WATER CUT [%]	96,15	98,16	94,34	98,40	98,20	97,68
OIL RATE [m³/d]	7,70	6,90	14,15	6,00	1,34	9,28
OIL RATE [bbl/d]	48,43	43,40	89,00	37,74	8,42	58,37
WATER RATE [m³/d]	192,30	368,10	235,85	369,00	73,04	390,72
PORTION OF TOTAL WATER RATE	0,0126	0,0242	0,0155	0,0243	0,0048	0,0257
ENERGY COSTS [EUR/year]	35.478	78.840	59.130	78.840	6.307	98.550
OIL TREATMENT COSTS [EUR/year]	7.439	6.666	13.670	5.797	1.293	8.965
WATER TREATMENT COSTS [EUR/year]	22.208	42.510	27.237	42.613	8.435	45.122
MTBF [days]	860	1.070	1.070	1.070	1.040	1.070
WI COSTS [EUR/year]	71.260	57.274	57.274	57.274	17.302	57.274
OPEX [EUR/year]	**136.384**	**185.290**	**157.311**	**184.524**	**33.338**	**209.911**
OPEX [EUR/m³]	**48,53**	**73,57**	**30,46**	**84,26**	**68,22**	**61,97**
OPEX [EUR/bbl]	**7,71**	**11,70**	**4,84**	**13,40**	**10,85**	**9,85**
OPEX Savings [EUR/bbl]	**0,64**	**1,37**	**0,43**	**1,58**	**1,40**	**1,08**
Pump Type	**ESP**	**ESP**	**ESP**	**SRP**	**ESP**	**ESP**
WELL No.	**BO_024**	**BO_025**	**BO_028**	**BO_030**	**BO_031**	**BO_035**
ENERGY CONSUMPTION [kW]	75,00	100,00	151,60	8,00	75,00	75,00
GROSS RATE [m³/d]	250,00	304,63	538,44	39,57	263,81	250,00
WATER CUT [%]	94,87	96,46	97,33	94,60	98,51	97,98
OIL RATE [m³/d]	12,83	10,78	14,38	2,14	3,93	5,05
OIL RATE [bbl/d]	80,67	67,83	90,43	13,44	24,72	31,76
WATER RATE [m³/d]	237,18	293,84	524,07	37,44	259,88	244,95
PORTION OF TOTAL WATER RATE	0,0156	0,0193	0,0345	0,0025	0,0171	0,0161
ENERGY COSTS [EUR/year]	59.130	78.840	119.521	6.307	59.130	59.130
OIL TREATMENT COSTS [EUR/year]	12.390	10.418	13.889	2.064	3.798	4.879
WATER TREATMENT COSTS [EUR/year]	27.390	33.934	60.521	4.323	30.012	28.288
MTBF [days]	1.070	1.070	1.070	1.040	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274	57.274	17.302	57.274	57.274
OPEX [EUR/year]	**156.184**	**180.466**	**251.206**	**29.997**	**150.214**	**149.571**
OPEX [EUR/m³]	**33,36**	**45,85**	**47,87**	**38,46**	**104,70**	**81,15**
OPEX [EUR/bbl]	**5,30**	**7,29**	**7,61**	**6,11**	**16,65**	**12,90**
OPEX Savings [EUR/bbl]	**0,48**	**0,70**	**0,94**	**0,45**	**1,70**	**1,25**
Pump Type	**ESP**	**ESP**	**SRP**	**ESP**	**ESP**	**ESP**
WELL No.	**BO_037**	**BO_038**	**BO_042**	**BO_043**	**BO_044**	**BO_045**
ENERGY CONSUMPTION [kW]	75,00	40,00	11,00	45,00	40,00	151,60
GROSS RATE [m³/d]	250,00	164,29	97,20	220,00	126,99	500,00
WATER CUT [%]	96,88	97,80	98,51	94,01	98,87	97,91
OIL RATE [m³/d]	7,80	3,61	1,45	13,18	1,43	10,45
OIL RATE [bbl/d]	49,06	22,73	9,11	82,89	9,03	65,73
WATER RATE [m³/d]	242,20	160,67	95,75	206,82	125,55	489,55
PORTION OF TOTAL WATER RATE	0,0159	0,0106	0,0063	0,0136	0,0083	0,0322
ENERGY COSTS [EUR/year]	59.130	31.536	8.672	35.478	31.536	119.521
OIL TREATMENT COSTS [EUR/year]	7.536	3.492	1.399	12.731	1.386	10.096
WATER TREATMENT COSTS [EUR/year]	27.970	18.555	11.058	23.885	14.499	56.535
MTBF [days]	1.070	540	1.145	860	540	1.070
WI COSTS [EUR/year]	57.274	113.488	15.716	71.260	113.488	57.274
OPEX [EUR/year]	**151.910**	**167.071**	**36.845**	**143.354**	**160.909**	**243.426**
OPEX [EUR/m³]	**53,36**	**126,64**	**69,70**	**29,80**	**307,23**	**63,82**
OPEX [EUR/bbl]	**8,48**	**20,13**	**11,08**	**4,74**	**48,84**	**10,15**
OPEX Savings [EUR/bbl]	**0,80**	**1,14**	**1,70**	**0,40**	**2,25**	**1,21**

Pump Type	ESP	SRP	ESP	ESP	SRP	SRP
WELL No.	BO_048	BO_049	BO_050	BO_53	BO_54	BO_55
ENERGY CONSUMPTION [kW]	75,00	11,00	35,00	35,00	17,00	11,00
GROSS RATE [m³/d]	250,00	110,85	116,98	86,51	150,00	124,93
WATER CUT [%]	97,25	95,96	98,35	99,21	92,41	95,15
OIL RATE [m³/d]	6,88	4,48	1,93	0,68	11,39	6,06
OIL RATE [bbl/d]	43,24	28,17	12,14	4,30	71,61	38,11
WATER RATE [m³/d]	243,13	106,37	115,05	85,82	138,62	118,87
PORTION OF TOTAL WATER RATE	0,0160	0,0070	0,0076	0,0056	0,0091	0,0078
ENERGY COSTS [EUR/year]	59.130	8.672	27.594	27.594	13.403	8.672
OIL TREATMENT COSTS [EUR/year]	6.642	4.326	1.865	660	10.999	5.854
WATER TREATMENT COSTS [EUR/year]	28.077	12.284	13.286	9.911	16.008	13.728
MTBF [days]	1.070	1.145	790	790	740	1.145
WI COSTS [EUR/year]	57.274	15.716	77.574	77.574	24.317	15.716
OPEX [EUR/year]	**151.123**	**40.999**	**120.319**	**115.739**	**64.726**	**43.970**
OPEX [EUR/m³]	**60,22**	**25,08**	**170,79**	**464,00**	**15,58**	**19,88**
OPEX [EUR/bbl]	**9,57**	**3,99**	**27,15**	**73,77**	**2,48**	**3,16**
OPEX Savings [EUR/bbl]	**0,91**	**0,61**	**1,53**	**3,23**	**0,31**	**0,50**

Pump Type	SRP	SRP	ESP	ESP	ESP	SRP
WELL No.	BO_56	BO_57	BO_063	BO_066	BO_068	BO_073
ENERGY CONSUMPTION [kW]	11,00	8,00	45,00	100,00	100,00	8,00
GROSS RATE [m³/d]	115,53	63,93	200,00	375,00	375,00	21,44
WATER CUT [%]	97,99	92,85	96,10	95,69	96,60	92,24
OIL RATE [m³/d]	2,32	4,57	7,80	16,16	12,75	1,66
OIL RATE [bbl/d]	14,61	28,75	49,06	101,66	80,20	10,47
WATER RATE [m³/d]	113,21	59,36	192,20	358,84	362,25	19,78
PORTION OF TOTAL WATER RATE	0,0074	0,0039	0,0126	0,0236	0,0238	0,0013
ENERGY COSTS [EUR/year]	8.672	6.307	35.478	78.840	78.840	6.307
OIL TREATMENT COSTS [EUR/year]	2.243	4.416	7.536	15.615	12.318	1.608
WATER TREATMENT COSTS [EUR/year]	13.073	6.855	22.196	41.440	41.834	2.284
MTBF [days]	1.145	1.040	860	1.070	1.070	1.040
WI COSTS [EUR/year]	15.716	17.302	71.260	57.274	57.274	17.302
OPEX [EUR/year]	**39.705**	**34.880**	**136.469**	**193.169**	**190.266**	**27.502**
OPEX [EUR/m³]	**46,85**	**20,91**	**47,93**	**32,74**	**40,88**	**45,28**
OPEX [EUR/bbl]	**7,45**	**3,32**	**7,62**	**5,21**	**6,50**	**7,20**
OPEX Savings [EUR/bbl]	**1,25**	**0,33**	**0,63**	**0,57**	**0,73**	**0,31**

Pump Type	SRP	ESP	ESP	ESP	ESP	ESP
WELL No.	BO_074	BO_075	BO_078	BO_079	BO_080	BO_081
ENERGY CONSUMPTION [kW]	17,00	100,00	100,00	125,00	75,00	100,00
GROSS RATE [m³/d]	150,00	350,00	350,00	400,00	250,00	375,00
WATER CUT [%]	94,16	98,50	96,22	97,64	85,60	95,83
OIL RATE [m³/d]	8,76	5,25	13,23	9,44	36,00	15,64
OIL RATE [bbl/d]	55,10	33,02	83,22	59,38	226,44	98,36
WATER RATE [m³/d]	141,24	344,75	336,77	390,56	214,00	359,36
PORTION OF TOTAL WATER RATE	0,0093	0,0227	0,0221	0,0257	0,0141	0,0236
ENERGY COSTS [EUR/year]	13.403	78.840	78.840	98.550	59.130	78.840
OIL TREATMENT COSTS [EUR/year]	8.463	5.072	12.781	9.120	34.780	15.107
WATER TREATMENT COSTS [EUR/year]	16.311	39.813	38.891	45.103	24.714	41.500
MTBF [days]	740	1.070	1.070	1.070	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	57.274	57.274	57.274	57.274
OPEX [EUR/year]	**62.494**	**180.999**	**187.787**	**210.048**	**175.897**	**192.722**
OPEX [EUR/m³]	**19,55**	**94,45**	**38,89**	**60,96**	**13,39**	**33,77**
OPEX [EUR/bbl]	**3,11**	**15,02**	**6,18**	**9,69**	**2,13**	**5,37**
OPEX Savings [EUR/bbl]	**0,41**	**1,69**	**0,65**	**1,06**	**0,15**	**0,59**

Pump Type	ESP	ESP	SRP	ESP	ESP	SRP
WELL No.	BO_085	BO_089	BO_091	BO_095	BO_096	BO_098
ENERGY CONSUMPTION [kW]	100,00	100,00	8,00	100,00	45,00	8,00
GROSS RATE [m³/d]	375,00	350,00	39,66	350,00	200,00	40,00
WATER CUT [%]	95,86	94,70	93,72	96,35	90,97	87,94
OIL RATE [m³/d]	15,53	18,55	2,49	12,78	18,06	4,82
OIL RATE [bbl/d]	97,65	116,68	15,66	80,35	113,60	30,34
WATER RATE [m³/d]	359,48	331,45	37,17	337,23	181,94	35,18
PORTION OF TOTAL WATER RATE	0,0236	0,0218	0,0024	0,0222	0,0120	0,0023
ENERGY COSTS [EUR/year]	78.840	78.840	6.307	78.840	35.478	6.307
OIL TREATMENT COSTS [EUR/year]	14.999	17.921	2.406	12.342	17.448	4.660
WATER TREATMENT COSTS [EUR/year]	41.513	38.277	4.292	38.944	21.011	4.062
MTBF [days]	1.070	1.070	1.040	1.070	860	1.040
WI COSTS [EUR/year]	57.274	57.274	17.302	57.274	71.260	17.302
OPEX [EUR/year]	**192.626**	**192.312**	**30.308**	**187.400**	**145.197**	**32.332**
OPEX [EUR/m³]	**33,99**	**28,40**	**33,34**	**40,19**	**22,03**	**18,36**
OPEX [EUR/bbl]	**5,40**	**4,52**	**5,30**	**6,39**	**3,50**	**2,92**
OPEX Savings [EUR/bbl]	**0,60**	**0,46**	**0,38**	**0,68**	**0,26**	**0,19**

Pump Type	SRP	ESP	SRP	SRP	ESP	ESP
WELL No.	BO_101	BO_102	BO_103	BO_104	BO_110	BO_111
ENERGY CONSUMPTION [kW]	17,00	100,00	8,00	8,00	100,00	75,00
GROSS RATE [m³/d]	136,05	350,00	25,00	20,00	350,00	250,00
WATER CUT [%]	97,87	96,70	21,53	83,62	94,90	97,63
OIL RATE [m³/d]	2,90	11,55	19,62	3,28	17,85	5,93
OIL RATE [bbl/d]	18,23	72,65	123,39	20,61	112,28	37,27
WATER RATE [m³/d]	133,15	338,45	5,38	16,72	332,15	244,08
PORTION OF TOTAL WATER RATE	0,0088	0,0223	0,0004	0,0011	0,0218	0,0161
ENERGY COSTS [EUR/year]	13.403	78.840	6.307	6.307	78.840	59.130
OIL TREATMENT COSTS [EUR/year]	2.800	11.158	18.952	3.165	17.245	5.724
WATER TREATMENT COSTS [EUR/year]	15.376	39.085	622	1.931	38.358	28.187
MTBF [days]	740	1.070	1.040	1.040	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	17.302	17.302	57.274	57.274
OPEX [EUR/year]	**55.896**	**186.358**	**43.184**	**28.706**	**191.717**	**150.315**
OPEX [EUR/m³]	**52,85**	**44,21**	**6,03**	**24,01**	**29,43**	**69,51**
OPEX [EUR/bbl]	**8,40**	**7,03**	**0,96**	**3,82**	**4,68**	**11,05**
OPEX Savings [EUR/bbl]	**1,18**	**0,75**	**0,01**	**0,13**	**0,48**	**1,06**

Pump Type	SRP	ESP	ESP	ESP	SRP	ESP
WELL No.	BO_112	BO_115A	BO_117	BO_118	BO_119	BO_120
ENERGY CONSUMPTION [kW]	17,00	35,00	125,00	75,00	11,00	100,00
GROSS RATE [m³/d]	150,00	109,84	400,00	250,00	106,36	350,00
WATER CUT [%]	88,23	98,18	98,38	97,79	92,37	97,76
OIL RATE [m³/d]	17,66	2,00	6,48	5,52	8,12	7,84
OIL RATE [bbl/d]	111,05	12,57	40,76	34,75	51,04	49,31
WATER RATE [m³/d]	132,35	107,84	393,52	244,48	98,24	342,16
PORTION OF TOTAL WATER RATE	0,0087	0,0071	0,0259	0,0161	0,0065	0,0225
ENERGY COSTS [EUR/year]	13.403	27.594	98.550	59.130	8.672	78.840
OIL TREATMENT COSTS [EUR/year]	17.056	1.931	6.260	5.338	7.840	7.574
WATER TREATMENT COSTS [EUR/year]	15.284	12.454	45.445	28.233	11.345	39.514
MTBF [days]	740	790	1.070	1.070	1.145	1.070
WI COSTS [EUR/year]	24.317	77.574	57.274	57.274	15.716	57.274
OPEX [EUR/year]	**70.060**	**119.554**	**207.530**	**149.975**	**43.573**	**183.202**
OPEX [EUR/m³]	**10,87**	**163,84**	**87,74**	**74,37**	**14,71**	**64,02**
OPEX [EUR/bbl]	**1,73**	**26,05**	**13,95**	**11,82**	**2,34**	**10,18**
OPEX Savings [EUR/bbl]	**0,19**	**1,39**	**1,56**	**1,14**	**0,31**	**1,12**

Pump Type	ESP	SRP	SRP	ESP	ESP	ESP
WELL No.	**BO_121**	**BO_141**	**BO_151**	**BO_152**	**BO_153**	**BO_157**
ENERGY CONSUMPTION [kW]	75,00	11,00	17,00	100,00	45,00	125,00
GROSS RATE [m³/d]	250,00	110,00	132,60	350,00	211,43	400,00
WATER CUT [%]	95,22	92,80	96,55	97,32	97,60	98,20
OIL RATE [m³/d]	11,95	7,92	4,57	9,38	5,07	7,20
OIL RATE [bbl/d]	75,16	49,82	28,77	59,00	31,92	45,29
WATER RATE [m³/d]	238,05	102,08	128,02	340,62	206,35	392,80
PORTION OF TOTAL WATER RATE	0,0157	0,0067	0,0084	0,0224	0,0136	0,0258
ENERGY COSTS [EUR/year]	59.130	8.672	13.403	78.840	35.478	98.550
OIL TREATMENT COSTS [EUR/year]	11.545	7.651	4.420	9.062	4.902	6.956
WATER TREATMENT COSTS [EUR/year]	27.491	11.789	14.785	39.336	23.830	45.362
MTBF [days]	1.070	1.145	740	1.070	860	1.070
WI COSTS [EUR/year]	57.274	15.716	24.317	57.274	71.260	57.274
OPEX [EUR/year]	**155.440**	**43.828**	**56.924**	**184.512**	**135.471**	**208.142**
OPEX [EUR/m³]	**35,64**	**15,16**	**34,09**	**53,89**	**73,14**	**79,20**
OPEX [EUR/bbl]	**5,67**	**2,41**	**5,42**	**8,57**	**11,63**	**12,59**
OPEX Savings [EUR/bbl]	**0,51**	**0,33**	**0,72**	**0,93**	**1,05**	**1,40**

Pump Type	SRP	SRP	SRP	SRP	SRP	ESP
WELL No.	**BO_158**	**BO_182**	**BO_200**	**BO_201**	**BO_202**	**BO_203**
ENERGY CONSUMPTION [kW]	8,00	11,00	8,00	11,00	11,00	45,00
GROSS RATE [m³/d]	74,83	119,15	70,51	100,00	100,00	200,00
WATER CUT [%]	87,36	96,84	89,35	80,99	90,00	96,10
OIL RATE [m³/d]	9,46	3,77	7,51	19,01	10,00	7,80
OIL RATE [bbl/d]	59,49	23,68	47,24	119,57	62,90	49,06
WATER RATE [m³/d]	65,37	115,38	63,00	80,99	90,00	192,20
PORTION OF TOTAL WATER RATE	0,0043	0,0076	0,0041	0,0053	0,0059	0,0126
ENERGY COSTS [EUR/year]	6.307	8.672	6.307	8.672	8.672	35.478
OIL TREATMENT COSTS [EUR/year]	9.138	3.637	7.255	18.366	9.661	7.536
WATER TREATMENT COSTS [EUR/year]	7.549	13.325	7.276	9.353	10.394	22.196
MTBF [days]	1.040	1.145	1.040	1.145	1.145	860
WI COSTS [EUR/year]	17.302	15.716	17.302	15.716	15.716	71.260
OPEX [EUR/year]	**40.297**	**41.350**	**38.141**	**52.107**	**44.443**	**136.469**
OPEX [EUR/m³]	**11,67**	**30,09**	**13,91**	**7,51**	**12,18**	**47,93**
OPEX [EUR/bbl]	**1,86**	**4,78**	**2,21**	**1,19**	**1,94**	**7,62**
OPEX Savings [EUR/bbl]	**0,18**	**0,79**	**0,22**	**0,11**	**0,23**	**0,63**

Pump Type	ESP	ESP
WELL No.	**BO_204**	**BO_205**
ENERGY CONSUMPTION [kW]	151,60	151,60
GROSS RATE [m³/d]	700,00	700,00
WATER CUT [%]	96,00	85,60
OIL RATE [m³/d]	28,00	100,80
OIL RATE [bbl/d]	176,12	634,03
WATER RATE [m³/d]	672,00	599,20
PORTION OF TOTAL WATER RATE	0,0442	0,0394
ENERGY COSTS [EUR/year]	119.521	119.521
OIL TREATMENT COSTS [EUR/year]	27.051	97.383
WATER TREATMENT COSTS [EUR/year]	77.605	69.198
MTBF [days]	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274
OPEX [EUR/year]	**281.451**	**343.376**
OPEX [EUR/m³]	**27,54**	**9,33**
OPEX [EUR/bbl]	**4,38**	**1,48**
OPEX Savings [EUR/bbl]	**0,62**	**0,15**

Table 34: OPEX Bockfließ Area – Tanks & PPS Water Treatment

Pump Type	**ESP**	**ESP**	**ESP**	**ESP**	**SRP**	**ESP**
WELL No.	**BO_003**	**BO_005**	**BO_006A**	**BO_011**	**BO_014**	**BO_023**
ENERGY CONSUMPTION [kW]	45,00	100,00	75,00	100,00	8,00	125,00
GROSS RATE [m³/d]	200,00	375,00	250,00	375,00	74,38	400,00
WATER CUT [%]	96,15	98,16	94,34	98,40	98,20	97,68
OIL RATE [m³/d]	7,70	6,90	14,15	6,00	1,34	9,28
OIL RATE [bbl/d]	48,43	43,40	89,00	37,74	8,42	58,37
WATER RATE [m³/d]	192,30	368,10	235,85	369,00	73,04	390,72
PORTION OF TOTAL WATER RATE	0,0126	0,0242	0,0155	0,0243	0,0048	0,0257
ENERGY COSTS [EUR/year]	35.478	78.840	59.130	78.840	6.307	98.550
OIL TREATMENT COSTS [EUR/year]	7.439	6.666	13.670	5.797	1.293	8.965
WATER TREATMENT COSTS [EUR/year]	16.927	32.402	20.761	32.482	6.429	34.393
MTBF [days]	860	1.070	1.070	1.070	1.040	1.070
WI COSTS [EUR/year]	71.260	57.274	57.274	57.274	17.302	57.274
OPEX [EUR/year]	**131.104**	**175.183**	**150.835**	**174.392**	**31.332**	**199.183**
OPEX [EUR/m³]	**46,65**	**69,56**	**29,20**	**79,63**	**64,12**	**58,80**
OPEX [EUR/bbl]	**7,42**	**11,06**	**4,64**	**12,66**	**10,19**	**9,35**
OPEX Savings [EUR/bbl]	**0,94**	**2,01**	**0,63**	**2,32**	**2,06**	**1,59**
Pump Type	**ESP**	**ESP**	**ESP**	**SRP**	**ESP**	**ESP**
WELL No.	**BO_024**	**BO_025**	**BO_028**	**BO_030**	**BO_031**	**BO_035**
ENERGY CONSUMPTION [kW]	75,00	100,00	151,60	8,00	75,00	75,00
GROSS RATE [m³/d]	250,00	304,63	538,44	39,57	263,81	250,00
WATER CUT [%]	94,87	96,46	97,33	94,60	98,51	97,98
OIL RATE [m³/d]	12,83	10,78	14,38	2,14	3,93	5,05
OIL RATE [bbl/d]	80,67	67,83	90,43	13,44	24,72	31,76
WATER RATE [m³/d]	237,18	293,84	524,07	37,44	259,88	244,95
PORTION OF TOTAL WATER RATE	0,0156	0,0193	0,0345	0,0025	0,0171	0,0161
ENERGY COSTS [EUR/year]	59.130	78.840	119.521	6.307	59.130	59.130
OIL TREATMENT COSTS [EUR/year]	12.390	10.418	13.889	2.064	3.798	4.879
WATER TREATMENT COSTS [EUR/year]	20.878	25.866	46.131	3.295	22.876	21.562
MTBF [days]	1.070	1.070	1.070	1.040	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274	57.274	17.302	57.274	57.274
OPEX [EUR/year]	**149.672**	**172.398**	**236.816**	**28.969**	**143.078**	**142.845**
OPEX [EUR/m³]	**31,97**	**43,80**	**45,13**	**37,14**	**99,72**	**77,50**
OPEX [EUR/bbl]	**5,08**	**6,96**	**7,17**	**5,90**	**15,85**	**12,32**
OPEX Savings [EUR/bbl]	**0,70**	**1,03**	**1,37**	**0,66**	**2,49**	**1,83**
Pump Type	**ESP**	**ESP**	**SRP**	**ESP**	**ESP**	**ESP**
WELL No.	**BO_037**	**BO_038**	**BO_042**	**BO_043**	**BO_044**	**BO_045**
ENERGY CONSUMPTION [kW]	75,00	40,00	11,00	45,00	40,00	151,60
GROSS RATE [m³/d]	250,00	164,29	97,20	220,00	126,99	500,00
WATER CUT [%]	96,88	97,80	98,51	94,01	98,87	97,91
OIL RATE [m³/d]	7,80	3,61	1,45	13,18	1,43	10,45
OIL RATE [bbl/d]	49,06	22,73	9,11	82,89	9,03	65,73
WATER RATE [m³/d]	242,20	160,67	95,75	206,82	125,55	489,55
PORTION OF TOTAL WATER RATE	0,0159	0,0106	0,0063	0,0136	0,0083	0,0322
ENERGY COSTS [EUR/year]	59.130	31.536	8.672	35.478	31.536	119.521
OIL TREATMENT COSTS [EUR/year]	7.536	3.492	1.399	12.731	1.386	10.096
WATER TREATMENT COSTS [EUR/year]	21.320	14.144	8.429	18.206	11.052	43.093
MTBF [days]	1.070	540	1.145	860	540	1.070
WI COSTS [EUR/year]	57.274	113.488	15.716	71.260	113.488	57.274
OPEX [EUR/year]	**145.260**	**162.659**	**34.216**	**137.675**	**157.462**	**229.985**
OPEX [EUR/m³]	**51,02**	**123,30**	**64,73**	**28,62**	**300,64**	**60,30**
OPEX [EUR/bbl]	**8,11**	**19,60**	**10,29**	**4,55**	**47,80**	**9,59**
OPEX Savings [EUR/bbl]	**1,17**	**1,68**	**2,49**	**0,59**	**3,30**	**1,77**

Pump Type	ESP	SRP	ESP	ESP	SRP	SRP
WELL No.	BO_048	BO_049	BO_050	BO_53	BO_54	BO_55
ENERGY CONSUMPTION [kW]	75,00	11,00	35,00	35,00	17,00	11,00
GROSS RATE [m³/d]	250,00	110,85	116,98	86,51	150,00	124,93
WATER CUT [%]	97,25	95,96	98,35	99,21	92,41	95,15
OIL RATE [m³/d]	6,88	4,48	1,93	0,68	11,39	6,06
OIL RATE [bbl/d]	43,24	28,17	12,14	4,30	71,61	38,11
WATER RATE [m³/d]	243,13	106,37	115,05	85,82	138,62	118,87
PORTION OF TOTAL WATER RATE	0,0160	0,0070	0,0076	0,0056	0,0091	0,0078
ENERGY COSTS [EUR/year]	59.130	8.672	27.594	27.594	13.403	8.672
OIL TREATMENT COSTS [EUR/year]	6.642	4.326	1.865	660	10.999	5.854
WATER TREATMENT COSTS [EUR/year]	21.401	9.363	10.127	7.555	12.202	10.464
MTBF [days]	1.070	1.145	790	790	740	1.145
WI COSTS [EUR/year]	57.274	15.716	77.574	77.574	24.317	15.716
OPEX [EUR/year]	**144.448**	**38.078**	**117.160**	**113.383**	**60.920**	**40.706**
OPEX [EUR/m³]	**57,56**	**23,30**	**166,30**	**454,55**	**14,66**	**18,41**
OPEX [EUR/bbl]	**9,15**	**3,70**	**26,44**	**72,27**	**2,33**	**2,93**
OPEX Savings [EUR/bbl]	**1,33**	**0,90**	**2,25**	**4,73**	**0,46**	**0,74**

Pump Type	SRP	SRP	ESP	ESP	ESP	SRP
WELL No.	BO_56	BO_57	BO_063	BO_066	BO_068	BO_073
ENERGY CONSUMPTION [kW]	11,00	8,00	45,00	100,00	100,00	8,00
GROSS RATE [m³/d]	115,53	63,93	200,00	375,00	375,00	21,44
WATER CUT [%]	97,99	92,85	96,10	95,69	96,60	92,24
OIL RATE [m³/d]	2,32	4,57	7,80	16,16	12,75	1,66
OIL RATE [bbl/d]	14,61	28,75	49,06	101,66	80,20	10,47
WATER RATE [m³/d]	113,21	59,36	192,20	358,84	362,25	19,78
PORTION OF TOTAL WATER RATE	0,0074	0,0039	0,0126	0,0236	0,0238	0,0013
ENERGY COSTS [EUR/year]	8.672	6.307	35.478	78.840	78.840	6.307
OIL TREATMENT COSTS [EUR/year]	2.243	4.416	7.536	15.615	12.318	1.608
WATER TREATMENT COSTS [EUR/year]	9.965	5.225	16.919	31.587	31.887	1.741
MTBF [days]	1.145	1.040	860	1.070	1.070	1.040
WI COSTS [EUR/year]	15.716	17.302	71.260	57.274	57.274	17.302
OPEX [EUR/year]	**36.597**	**33.250**	**131.192**	**183.316**	**180.319**	**26.958**
OPEX [EUR/m³]	**43,18**	**19,93**	**46,08**	**31,07**	**38,75**	**44,38**
OPEX [EUR/bbl]	**6,86**	**3,17**	**7,33**	**4,94**	**6,16**	**7,06**
OPEX Savings [EUR/bbl]	**1,84**	**0,49**	**0,93**	**0,84**	**1,07**	**0,45**

Pump Type	SRP	ESP	ESP	ESP	ESP	ESP
WELL No.	BO_074	BO_075	BO_078	BO_079	BO_080	BO_081
ENERGY CONSUMPTION [kW]	17,00	100,00	100,00	125,00	75,00	100,00
GROSS RATE [m³/d]	150,00	350,00	350,00	400,00	250,00	375,00
WATER CUT [%]	94,16	98,50	96,22	97,64	85,60	95,83
OIL RATE [m³/d]	8,76	5,25	13,23	9,44	36,00	15,64
OIL RATE [bbl/d]	55,10	33,02	83,22	59,38	226,44	98,36
WATER RATE [m³/d]	141,24	344,75	336,77	390,56	214,00	359,36
PORTION OF TOTAL WATER RATE	0,0093	0,0227	0,0221	0,0257	0,0141	0,0236
ENERGY COSTS [EUR/year]	13.403	78.840	78.840	98.550	59.130	78.840
OIL TREATMENT COSTS [EUR/year]	8.463	5.072	12.781	9.120	34.780	15.107
WATER TREATMENT COSTS [EUR/year]	12.433	30.347	29.644	34.379	18.838	31.633
MTBF [days]	740	1.070	1.070	1.070	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	57.274	57.274	57.274	57.274
OPEX [EUR/year]	**58.615**	**171.533**	**178.540**	**199.324**	**170.021**	**182.855**
OPEX [EUR/m³]	**18,33**	**89,52**	**36,97**	**57,85**	**12,94**	**32,04**
OPEX [EUR/bbl]	**2,91**	**14,23**	**5,88**	**9,20**	**2,06**	**5,09**
OPEX Savings [EUR/bbl]	**0,61**	**2,47**	**0,96**	**1,56**	**0,22**	**0,87**

Pump Type	ESP	ESP	SRP	ESP	ESP	SRP
WELL No.	BO_085	BO_089	BO_091	BO_095	BO_096	BO_098
ENERGY CONSUMPTION [kW]	100,00	100,00	8,00	100,00	45,00	8,00
GROSS RATE [m³/d]	375,00	350,00	39,66	350,00	200,00	40,00
WATER CUT [%]	95,86	94,70	93,72	96,35	90,97	87,94
OIL RATE [m³/d]	15,53	18,55	2,49	12,78	18,06	4,82
OIL RATE [bbl/d]	97,65	116,68	15,66	80,35	113,60	30,34
WATER RATE [m³/d]	359,48	331,45	37,17	337,23	181,94	35,18
PORTION OF TOTAL WATER RATE	0,0236	0,0218	0,0024	0,0222	0,0120	0,0023
ENERGY COSTS [EUR/year]	78.840	78.840	6.307	78.840	35.478	6.307
OIL TREATMENT COSTS [EUR/year]	14.999	17.921	2.406	12.342	17.448	4.660
WATER TREATMENT COSTS [EUR/year]	31.643	29.176	3.272	29.685	16.015	3.096
MTBF [days]	1.070	1.070	1.040	1.070	860	1.040
WI COSTS [EUR/year]	57.274	57.274	17.302	57.274	71.260	17.302
OPEX [EUR/year]	**182.756**	**183.212**	**29.287**	**178.141**	**140.201**	**31.366**
OPEX [EUR/m³]	**32,25**	**27,06**	**32,22**	**38,20**	**21,27**	**17,81**
OPEX [EUR/bbl]	**5,13**	**4,30**	**5,12**	**6,07**	**3,38**	**2,83**
OPEX Savings [EUR/bbl]	**0,87**	**0,67**	**0,56**	**0,99**	**0,38**	**0,27**

Pump Type	SRP	ESP	SRP	SRP	ESP	ESP
WELL No.	BO_101	BO_102	BO_103	BO_104	BO_110	BO_111
ENERGY CONSUMPTION [kW]	17,00	100,00	8,00	8,00	100,00	75,00
GROSS RATE [m³/d]	136,05	350,00	25,00	20,00	350,00	250,00
WATER CUT [%]	97,87	96,70	21,53	83,62	94,90	97,63
OIL RATE [m³/d]	2,90	11,55	19,62	3,28	17,85	5,93
OIL RATE [bbl/d]	18,23	72,65	123,39	20,61	112,28	37,27
WATER RATE [m³/d]	133,15	338,45	5,38	16,72	332,15	244,08
PORTION OF TOTAL WATER RATE	0,0088	0,0223	0,0004	0,0011	0,0218	0,0161
ENERGY COSTS [EUR/year]	13.403	78.840	6.307	6.307	78.840	59.130
OIL TREATMENT COSTS [EUR/year]	2.800	11.158	18.952	3.165	17.245	5.724
WATER TREATMENT COSTS [EUR/year]	11.720	29.792	474	1.472	29.238	21.485
MTBF [days]	740	1.070	1.040	1.040	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	17.302	17.302	57.274	57.274
OPEX [EUR/year]	**52.240**	**177.065**	**43.036**	**28.247**	**182.597**	**143.613**
OPEX [EUR/m³]	**49,39**	**42,00**	**6,01**	**23,62**	**28,03**	**66,41**
OPEX [EUR/bbl]	**7,85**	**6,68**	**0,96**	**3,76**	**4,46**	**10,56**
OPEX Savings [EUR/bbl]	**1,73**	**1,10**	**0,01**	**0,19**	**0,70**	**1,55**

Pump Type	SRP	ESP	ESP	ESP	SRP	ESP
WELL No.	BO_112	BO_115A	BO_117	BO_118	BO_119	BO_120
ENERGY CONSUMPTION [kW]	17,00	35,00	125,00	75,00	11,00	100,00
GROSS RATE [m³/d]	150,00	109,84	400,00	250,00	106,36	350,00
WATER CUT [%]	88,23	98,18	98,38	97,79	92,37	97,76
OIL RATE [m³/d]	17,66	2,00	6,48	5,52	8,12	7,84
OIL RATE [bbl/d]	111,05	12,57	40,76	34,75	51,04	49,31
WATER RATE [m³/d]	132,35	107,84	393,52	244,48	98,24	342,16
PORTION OF TOTAL WATER RATE	0,0087	0,0071	0,0259	0,0161	0,0065	0,0225
ENERGY COSTS [EUR/year]	13.403	27.594	98.550	59.130	8.672	78.840
OIL TREATMENT COSTS [EUR/year]	17.056	1.931	6.260	5.338	7.840	7.574
WATER TREATMENT COSTS [EUR/year]	11.650	9.493	34.640	21.520	8.648	30.119
MTBF [days]	740	790	1.070	1.070	1.145	1.070
WI COSTS [EUR/year]	24.317	77.574	57.274	57.274	15.716	57.274
OPEX [EUR/year]	**66.426**	**116.592**	**196.725**	**143.262**	**40.876**	**173.807**
OPEX [EUR/m³]	**10,31**	**159,78**	**83,17**	**71,04**	**13,80**	**60,74**
OPEX [EUR/bbl]	**1,64**	**25,40**	**13,22**	**11,29**	**2,19**	**9,66**
OPEX Savings [EUR/bbl]	**0,28**	**2,03**	**2,29**	**1,67**	**0,46**	**1,64**

Pump Type	ESP	SRP	SRP	ESP	ESP	ESP
WELL No.	BO_121	BO_141	BO_151	BO_152	BO_153	BO_157
ENERGY CONSUMPTION [kW]	75,00	11,00	17,00	100,00	45,00	125,00
GROSS RATE [m³/d]	250,00	110,00	132,60	350,00	211,43	400,00
WATER CUT [%]	95,22	92,80	96,55	97,32	97,60	98,20
OIL RATE [m³/d]	11,95	7,92	4,57	9,38	5,07	7,20
OIL RATE [bbl/d]	75,16	49,82	28,77	59,00	31,92	45,29
WATER RATE [m³/d]	238,05	102,08	128,02	340,62	206,35	392,80
PORTION OF TOTAL WATER RATE	0,0157	0,0067	0,0084	0,0224	0,0136	0,0258
ENERGY COSTS [EUR/year]	59.130	8.672	13.403	78.840	35.478	98.550
OIL TREATMENT COSTS [EUR/year]	11.545	7.651	4.420	9.062	4.902	6.956
WATER TREATMENT COSTS [EUR/year]	20.955	8.986	11.269	29.983	18.164	34.577
MTBF [days]	1.070	1.145	740	1.070	860	1.070
WI COSTS [EUR/year]	57.274	15.716	24.317	57.274	71.260	57.274
OPEX [EUR/year]	**148.904**	**41.025**	**53.409**	**175.160**	**129.805**	**197.357**
OPEX [EUR/m³]	**34,14**	**14,19**	**31,99**	**51,16**	**70,08**	**75,10**
OPEX [EUR/bbl]	**5,43**	**2,26**	**5,09**	**8,13**	**11,14**	**11,94**
OPEX Savings [EUR/bbl]	**0,75**	**0,49**	**1,05**	**1,37**	**1,53**	**2,06**

Pump Type	SRP	SRP	SRP	SRP	SRP	ESP
WELL No.	BO_158	BO_182	BO_200	BO_201	BO_202	BO_203
ENERGY CONSUMPTION [kW]	8,00	11,00	8,00	11,00	11,00	45,00
GROSS RATE [m³/d]	74,83	119,15	70,51	100,00	100,00	200,00
WATER CUT [%]	87,36	96,84	89,35	80,99	90,00	96,10
OIL RATE [m³/d]	9,46	3,77	7,51	19,01	10,00	7,80
OIL RATE [bbl/d]	59,49	23,68	47,24	119,57	62,90	49,06
WATER RATE [m³/d]	65,37	115,38	63,00	80,99	90,00	192,20
PORTION OF TOTAL WATER RATE	0,0043	0,0076	0,0041	0,0053	0,0059	0,0126
ENERGY COSTS [EUR/year]	6.307	8.672	6.307	8.672	8.672	35.478
OIL TREATMENT COSTS [EUR/year]	9.138	3.637	7.255	18.366	9.661	7.536
WATER TREATMENT COSTS [EUR/year]	5.754	10.157	5.546	7.129	7.922	16.919
MTBF [days]	1.040	1.145	1.040	1.145	1.145	860
WI COSTS [EUR/year]	17.302	15.716	17.302	15.716	15.716	71.260
OPEX [EUR/year]	**38.502**	**38.182**	**36.411**	**49.883**	**41.971**	**131.192**
OPEX [EUR/m³]	**11,15**	**27,78**	**13,28**	**7,19**	**11,50**	**46,08**
OPEX [EUR/bbl]	**1,77**	**4,42**	**2,11**	**1,14**	**1,83**	**7,33**
OPEX Savings [EUR/bbl]	**0,26**	**1,15**	**0,32**	**0,16**	**0,34**	**0,93**

Pump Type	ESP	ESP
WELL No.	BO_204	BO_205
ENERGY CONSUMPTION [kW]	151,60	151,60
GROSS RATE [m³/d]	700,00	700,00
WATER CUT [%]	96,00	85,60
OIL RATE [m³/d]	28,00	100,80
OIL RATE [bbl/d]	176,12	634,03
WATER RATE [m³/d]	672,00	599,20
PORTION OF TOTAL WATER RATE	0,0442	0,0394
ENERGY COSTS [EUR/year]	119.521	119.521
OIL TREATMENT COSTS [EUR/year]	27.051	97.383
WATER TREATMENT COSTS [EUR/year]	59.153	52.745
MTBF [days]	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274
OPEX [EUR/year]	**263.000**	**326.923**
OPEX [EUR/m³]	**25,73**	**8,89**
OPEX [EUR/bbl]	**4,09**	**1,41**
OPEX Savings [EUR/bbl]	**0,90**	**0,22**

Table 35: OPEX Bockfließ Area – Old Water Treatment

Pump Type	ESP	ESP	ESP	ESP	SRP	ESP
WELL No.	**BO_003**	**BO_005**	**BO_006A**	**BO_011**	**BO_014**	**BO_023**
ENERGY CONSUMPTION [kW]	45,00	100,00	75,00	100,00	8,00	125,00
GROSS RATE [m³/d]	200,00	375,00	250,00	375,00	74,38	400,00
WATER CUT [%]	96,15	98,16	94,34	98,40	98,20	97,68
OIL RATE [m³/d]	7,70	6,90	14,15	6,00	1,34	9,28
OIL RATE [bbl/d]	48,43	43,40	89,00	37,74	8,42	58,37
WATER RATE [m³/d]	192,30	368,10	235,85	369,00	73,04	390,72
ENERGY COSTS [EUR/year]	35.478	78.840	59.130	78.840	6.307	98.550
OIL TREATMENT COSTS [EUR/year]	7.439	6.666	13.670	5.797	1.293	8.965
WATER TREATMENT COSTS [EUR/year]	33.566	64.253	41.168	64.410	12.749	68.201
MTBF [days]	860	1.070	1.070	1.070	1.040	1.070
WI COSTS [EUR/year]	71.260	57.274	57.274	57.274	17.302	57.274
OPEX [EUR/year]	**147.743**	**207.033**	**171.243**	**206.321**	**37.652**	**232.991**
OPEX [EUR/m³]	**52,57**	**82,20**	**33,16**	**94,21**	**77,05**	**68,79**
OPEX [EUR/bbl]	**8,36**	**13,07**	**5,27**	**14,98**	**12,25**	**10,94**

Pump Type	ESP	ESP	ESP	SRP	ESP	ESP
WELL No.	**BO_024**	**BO_025**	**BO_028**	**BO_030**	**BO_031**	**BO_035**
ENERGY CONSUMPTION [kW]	75,00	100,00	151,60	8,00	75,00	75,00
GROSS RATE [m³/d]	250,00	304,63	538,44	39,57	263,81	250,00
WATER CUT [%]	94,87	96,46	97,33	94,60	98,51	97,98
OIL RATE [m³/d]	12,83	10,78	14,38	2,14	3,93	5,05
OIL RATE [bbl/d]	80,67	67,83	90,43	13,44	24,72	31,76
WATER RATE [m³/d]	237,18	293,84	524,07	37,44	259,88	244,95
ENERGY COSTS [EUR/year]	59.130	78.840	119.521	6.307	59.130	59.130
OIL TREATMENT COSTS [EUR/year]	12.390	10.418	13.889	2.064	3.798	4.879
WATER TREATMENT COSTS [EUR/year]	41.399	51.291	91.477	6.534	45.363	42.757
MTBF [days]	1.070	1.070	1.070	1.040	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274	57.274	17.302	57.274	57.274
OPEX [EUR/year]	**170.194**	**197.823**	**282.161**	**32.208**	**165.565**	**164.040**
OPEX [EUR/m³]	**36,36**	**50,26**	**53,77**	**41,29**	**115,40**	**88,99**
OPEX [EUR/bbl]	**5,78**	**7,99**	**8,55**	**6,57**	**18,35**	**14,15**

Pump Type	ESP	ESP	SRP	ESP	ESP	ESP
WELL No.	**BO_037**	**BO_038**	**BO_042**	**BO_043**	**BO_044**	**BO_045**
ENERGY CONSUMPTION [kW]	75,00	40,00	11,00	45,00	40,00	151,60
GROSS RATE [m³/d]	250,00	164,29	97,20	220,00	126,99	500,00
WATER CUT [%]	96,88	97,80	98,51	94,01	98,87	97,91
OIL RATE [m³/d]	7,80	3,61	1,45	13,18	1,43	10,45
OIL RATE [bbl/d]	49,06	22,73	9,11	82,89	9,03	65,73
WATER RATE [m³/d]	242,20	160,67	95,75	206,82	125,55	489,55
ENERGY COSTS [EUR/year]	59.130	31.536	8.672	35.478	31.536	119.521
OIL TREATMENT COSTS [EUR/year]	7.536	3.492	1.399	12.731	1.386	10.096
WATER TREATMENT COSTS [EUR/year]	42.276	28.046	16.714	36.101	21.915	85.452
MTBF [days]	1.070	540	1.145	860	540	1.070
WI COSTS [EUR/year]	57.274	113.488	15.716	71.260	113.488	57.274
OPEX [EUR/year]	**166.216**	**176.562**	**42.501**	**155.570**	**168.325**	**272.343**
OPEX [EUR/m³]	**58,38**	**133,84**	**80,40**	**32,34**	**321,38**	**71,40**
OPEX [EUR/bbl]	**9,28**	**21,28**	**12,78**	**5,14**	**51,10**	**11,35**

Pump Type	ESP	SRP	ESP	ESP	SRP	SRP
WELL No.	BO_048	BO_049	BO_050	BO_53	BO_54	BO_55
ENERGY CONSUMPTION [kW]	75,00	11,00	35,00	35,00	17,00	11,00
GROSS RATE [m³/d]	250,00	110,85	116,98	86,51	150,00	124,93
WATER CUT [%]	97,25	95,96	98,35	99,21	92,41	95,15
OIL RATE [m³/d]	6,88	4,48	1,93	0,68	11,39	6,06
OIL RATE [bbl/d]	43,24	28,17	12,14	4,30	71,61	38,11
WATER RATE [m³/d]	243,13	106,37	115,05	85,82	138,62	118,87
ENERGY COSTS [EUR/year]	59.130	8.672	27.594	27.594	13.403	8.672
OIL TREATMENT COSTS [EUR/year]	6.642	4.326	1.865	660	10.999	5.854
WATER TREATMENT COSTS [EUR/year]	42.438	18.567	20.082	14.981	24.196	20.750
MTBF [days]	1.070	1.145	790	790	740	1.145
WI COSTS [EUR/year]	57.274	15.716	77.574	77.574	24.317	15.716
OPEX [EUR/year]	**165.484**	**47.282**	**127.115**	**120.809**	**72.914**	**50.992**
OPEX [EUR/m³]	**65,95**	**28,93**	**180,43**	**484,32**	**17,55**	**23,06**
OPEX [EUR/bbl]	**10,48**	**4,60**	**28,69**	**77,00**	**2,79**	**3,67**

Pump Type	SRP	SRP	ESP	ESP	ESP	SRP
WELL No.	BO_56	BO_57	BO_063	BO_066	BO_068	BO_073
ENERGY CONSUMPTION [kW]	11,00	8,00	45,00	100,00	100,00	8,00
GROSS RATE [m³/d]	115,53	63,93	200,00	375,00	375,00	21,44
WATER CUT [%]	97,99	92,85	96,10	95,69	96,60	92,24
OIL RATE [m³/d]	2,32	4,57	7,80	16,16	12,75	1,66
OIL RATE [bbl/d]	14,61	28,75	49,06	101,66	80,20	10,47
WATER RATE [m³/d]	113,21	59,36	192,20	358,84	362,25	19,78
ENERGY COSTS [EUR/year]	8.672	6.307	35.478	78.840	78.840	6.307
OIL TREATMENT COSTS [EUR/year]	2.243	4.416	7.536	15.615	12.318	1.608
WATER TREATMENT COSTS [EUR/year]	19.760	10.361	33.549	62.636	63.231	3.453
MTBF [days]	1.145	1.040	860	1.070	1.070	1.040
WI COSTS [EUR/year]	15.716	17.302	71.260	57.274	57.274	17.302
OPEX [EUR/year]	**46.392**	**38.386**	**147.822**	**214.365**	**211.664**	**28.670**
OPEX [EUR/m³]	**54,74**	**23,01**	**51,92**	**36,34**	**45,48**	**47,20**
OPEX [EUR/bbl]	**8,70**	**3,66**	**8,25**	**5,78**	**7,23**	**7,50**

Pump Type	SRP	ESP	ESP	ESP	ESP	ESP
WELL No.	BO_074	BO_075	BO_078	BO_079	BO_080	BO_081
ENERGY CONSUMPTION [kW]	17,00	100,00	100,00	125,00	75,00	100,00
GROSS RATE [m³/d]	150,00	350,00	350,00	400,00	250,00	375,00
WATER CUT [%]	94,16	98,50	96,22	97,64	85,60	95,83
OIL RATE [m³/d]	8,76	5,25	13,23	9,44	36,00	15,64
OIL RATE [bbl/d]	55,10	33,02	83,22	59,38	226,44	98,36
WATER RATE [m³/d]	141,24	344,75	336,77	390,56	214,00	359,36
ENERGY COSTS [EUR/year]	13.403	78.840	78.840	98.550	59.130	78.840
OIL TREATMENT COSTS [EUR/year]	8.463	5.072	12.781	9.120	34.780	15.107
WATER TREATMENT COSTS [EUR/year]	24.654	60.177	58.784	68.173	37.354	62.727
MTBF [days]	740	1.070	1.070	1.070	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	57.274	57.274	57.274	57.274
OPEX [EUR/year]	**70.836**	**201.363**	**207.680**	**233.117**	**188.538**	**213.949**
OPEX [EUR/m³]	**22,15**	**105,08**	**43,01**	**67,66**	**14,35**	**37,48**
OPEX [EUR/bbl]	**3,52**	**16,71**	**6,84**	**10,76**	**2,28**	**5,96**

Pump Type	ESP	ESP	SRP	ESP	ESP	SRP
WELL No.	BO_085	BO_089	BO_091	BO_095	BO_096	BO_098
ENERGY CONSUMPTION [kW]	100,00	100,00	8,00	100,00	45,00	8,00
GROSS RATE [m³/d]	375,00	350,00	39,66	350,00	200,00	40,00
WATER CUT [%]	95,86	94,70	93,72	96,35	90,97	87,94
OIL RATE [m³/d]	15,53	18,55	2,49	12,78	18,06	4,82
OIL RATE [bbl/d]	97,65	116,68	15,66	80,35	113,60	30,34
WATER RATE [m³/d]	359,48	331,45	37,17	337,23	181,94	35,18
ENERGY COSTS [EUR/year]	78.840	78.840	6.307	78.840	35.478	6.307
OIL TREATMENT COSTS [EUR/year]	14.999	17.921	2.406	12.342	17.448	4.660
WATER TREATMENT COSTS [EUR/year]	62.747	57.855	6.487	58.863	31.758	6.140
MTBF [days]	1.070	1.070	1.040	1.070	860	1.040
WI COSTS [EUR/year]	57.274	57.274	17.302	57.274	71.260	17.302
OPEX [EUR/year]	**213.860**	**211.891**	**32.503**	**207.319**	**155.944**	**34.410**
OPEX [EUR/m³]	**37,74**	**31,30**	**35,76**	**44,46**	**23,66**	**19,54**
OPEX [EUR/bbl]	**6,00**	**4,98**	**5,68**	**7,07**	**3,76**	**3,11**
Pump Type	**SRP**	**ESP**	**SRP**	**SRP**	**ESP**	**ESP**
WELL No.	**BO_101**	**BO_102**	**BO_103**	**BO_104**	**BO_110**	**BO_111**
ENERGY CONSUMPTION [kW]	17,00	100,00	8,00	8,00	100,00	75,00
GROSS RATE [m³/d]	136,05	350,00	25,00	20,00	350,00	250,00
WATER CUT [%]	97,87	96,70	21,53	83,62	94,90	97,63
OIL RATE [m³/d]	2,90	11,55	19,62	3,28	17,85	5,93
OIL RATE [bbl/d]	18,23	72,65	123,39	20,61	112,28	37,27
WATER RATE [m³/d]	133,15	338,45	5,38	16,72	332,15	244,08
ENERGY COSTS [EUR/year]	13.403	78.840	6.307	6.307	78.840	59.130
OIL TREATMENT COSTS [EUR/year]	2.800	11.158	18.952	3.165	17.245	5.724
WATER TREATMENT COSTS [EUR/year]	23.241	59.077	940	2.919	57.977	42.604
MTBF [days]	740	1.070	1.040	1.040	1.070	1.070
WI COSTS [EUR/year]	24.317	57.274	17.302	17.302	57.274	57.274
OPEX [EUR/year]	**63.760**	**206.350**	**43.502**	**29.694**	**211.337**	**164.732**
OPEX [EUR/m³]	**60,28**	**48,95**	**6,08**	**24,83**	**32,44**	**76,17**
OPEX [EUR/bbl]	**9,58**	**7,78**	**0,97**	**3,95**	**5,16**	**12,11**
Pump Type	**SRP**	**ESP**	**ESP**	**ESP**	**SRP**	**ESP**
WELL No.	**BO_112**	**BO_115A**	**BO_117**	**BO_118**	**BO_119**	**BO_120**
ENERGY CONSUMPTION [kW]	17,00	35,00	125,00	75,00	11,00	100,00
GROSS RATE [m³/d]	150,00	109,84	400,00	250,00	106,36	350,00
WATER CUT [%]	88,23	98,18	98,38	97,79	92,37	97,76
OIL RATE [m³/d]	17,66	2,00	6,48	5,52	8,12	7,84
OIL RATE [bbl/d]	111,05	12,57	40,76	34,75	51,04	49,31
WATER RATE [m³/d]	132,35	107,84	393,52	244,48	98,24	342,16
ENERGY COSTS [EUR/year]	13.403	27.594	98.550	59.130	8.672	78.840
OIL TREATMENT COSTS [EUR/year]	17.056	1.931	6.260	5.338	7.840	7.574
WATER TREATMENT COSTS [EUR/year]	23.101	18.824	68.690	42.674	17.148	59.725
MTBF [days]	740	790	1.070	1.070	1.145	1.070
WI COSTS [EUR/year]	24.317	77.574	57.274	57.274	15.716	57.274
OPEX [EUR/year]	**77.877**	**125.924**	**230.774**	**164.416**	**49.376**	**203.413**
OPEX [EUR/m³]	**12,09**	**172,57**	**97,57**	**81,53**	**16,67**	**71,08**
OPEX [EUR/bbl]	**1,92**	**27,44**	**15,51**	**12,96**	**2,65**	**11,30**

Pump Type	ESP	SRP	SRP	ESP	ESP	ESP
WELL No.	BO_121	BO_141	BO_151	BO_152	BO_153	BO_157
ENERGY CONSUMPTION [kW]	75,00	11,00	17,00	100,00	45,00	125,00
GROSS RATE [m³/d]	250,00	110,00	132,60	350,00	211,43	400,00
WATER CUT [%]	95,22	92,80	96,55	97,32	97,60	98,20
OIL RATE [m³/d]	11,95	7,92	4,57	9,38	5,07	7,20
OIL RATE [bbl/d]	75,16	49,82	28,77	59,00	31,92	45,29
WATER RATE [m³/d]	238,05	102,08	128,02	340,62	206,35	392,80
ENERGY COSTS [EUR/year]	59.130	8.672	13.403	78.840	35.478	98.550
OIL TREATMENT COSTS [EUR/year]	11.545	7.651	4.420	9.062	4.902	6.956
WATER TREATMENT COSTS [EUR/year]	41.552	17.818	22.347	59.456	36.019	68.564
MTBF [days]	1.070	1.145	740	1.070	860	1.070
WI COSTS [EUR/year]	57.274	15.716	24.317	57.274	71.260	57.274
OPEX [EUR/year]	**169.501**	**49.858**	**64.486**	**204.632**	**147.660**	**231.344**
OPEX [EUR/m³]	**38,86**	**17,25**	**38,62**	**59,77**	**79,73**	**88,03**
OPEX [EUR/bbl]	**6,18**	**2,74**	**6,14**	**9,50**	**12,68**	**14,00**

Pump Type	SRP	SRP	SRP	SRP	SRP	ESP
WELL No.	BO_158	BO_182	BO_200	BO_201	BO_202	BO_203
ENERGY CONSUMPTION [kW]	8,00	11,00	8,00	11,00	11,00	45,00
GROSS RATE [m³/d]	74,83	119,15	70,51	100,00	100,00	200,00
WATER CUT [%]	87,36	96,84	89,35	80,99	90,00	96,10
OIL RATE [m³/d]	9,46	3,77	7,51	19,01	10,00	7,80
OIL RATE [bbl/d]	59,49	23,68	47,24	119,57	62,90	49,06
WATER RATE [m³/d]	65,37	115,38	63,00	80,99	90,00	192,20
ENERGY COSTS [EUR/year]	6.307	8.672	6.307	8.672	8.672	35.478
OIL TREATMENT COSTS [EUR/year]	9.138	3.637	7.255	18.366	9.661	7.536
WATER TREATMENT COSTS [EUR/year]	11.411	20.140	10.997	14.137	15.710	33.549
MTBF [days]	1.040	1.145	1.040	1.145	1.145	860
WI COSTS [EUR/year]	17.302	15.716	17.302	15.716	15.716	71.260
OPEX [EUR/year]	**44.158**	**48.166**	**41.862**	**56.891**	**49.759**	**147.822**
OPEX [EUR/m³]	**12,79**	**35,05**	**15,27**	**8,20**	**13,63**	**51,92**
OPEX [EUR/bbl]	**2,03**	**5,57**	**2,43**	**1,30**	**2,17**	**8,25**

Pump Type	ESP	ESP
WELL No.	BO_204	BO_205
ENERGY CONSUMPTION [kW]	151,60	151,60
GROSS RATE [m³/d]	700,00	700,00
WATER CUT [%]	96,00	85,60
OIL RATE [m³/d]	28,00	100,80
OIL RATE [bbl/d]	176,12	634,03
WATER RATE [m³/d]	672,00	599,20
ENERGY COSTS [EUR/year]	119.521	119.521
OIL TREATMENT COSTS [EUR/year]	27.051	97.383
WATER TREATMENT COSTS [EUR/year]	117.299	104.592
MTBF [days]	1.070	1.070
WI COSTS [EUR/year]	57.274	57.274
OPEX [EUR/year]	**321.145**	**378.770**
OPEX [EUR/m³]	**31,42**	**10,29**
OPEX [EUR/bbl]	**5,00**	**1,64**