POWER-GEN Middle East 2014

Alternative Fuels for Power Generation within Oil and Gas Industry

By

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Abbreviations

CRO	Crude Oil
NG	Natural Gas
PSA	Production Share Agreement
AG	Associated Gases
bbl	Barrels
scf	Standard Cubic Feet
M	Thousand
MM	Million
CFP	Central Production Facility
GPF	Gas Processing Facility
GT	Gas Turbine
OC	Operating Company
CAPEX	Capital Cost (investment)
OPEX	Operational Cost
FEED	Front End Engineering Design

ABSTRACT

The world's total equivalent oil production is more than 80 million barrels per day. The constant new discoveries of conventional oil sources, together with the strong emergence recently of unconventional oil production, are more than compensating for the depletion rate of old wells that are being decommissioned annually. In fact, the number of new discoveries has changed the mainstream estimation of oil reserves to be adequate, not only for the coming thirty years, but rather for at least the coming hundred years.

In the production, transportation and refining of oil and gas, the power consumption is considerable per produced barrel of oil. A barrel of raw oil from the well will "consume" tens and sometimes hundreds of kWh of power before the final saleable products can be retailed. This power is often produced by dedicated power units and power plants, embedded within the production site. These plants are fuelled by locally available fuels, often gas, which is extracted as a side stream from the oil and gas production process.

The side streams often used are actually natural gas, or the raw material for natural gas. For decades these streams have been considered as being free of charge – without a "price", which has led to extremely wasteful management of potentially saleable resources. In addition, taking into consideration the fact that power has often been generated using low efficiency prime movers with net electrical efficiencies well below 30%, the waste of resources has been further aggravated and the oil and gas industry's CO_2 footprint has been enlarged.

Today's oil and gas industry is constantly striving to improve the economics of its operations and to reduce the harmful impact on the environment of the operations. This has changed the attitude of the industry, causing it to look into its decades old practices regarding power generation. The fuel is no longer necessarily looked upon as being free of charge – rather as a saleable product, plus the power generation efficiency should be higher than the current average, and the CO_2 footprint per produced barrel should be minimised.

One way to improve efficiency is to look at what other fuels are available at the production process site. Could some of the "waste" flows actually be considered as fuels in the future? Can the existing natural gas based fuels actually be sold thus increasing revenues? And are there more effective technologies with fuel flexibility and higher electrical efficiencies available for power generation?

In this paper, we shall look into the above questions and the available hydrocarbon chain from the oil and gas production field, and we shall examine how the various streams in the processes - not normally considered as fuel, could be utilized for power production. We shall also look at the possibilities for increasing the electrical efficiency of the power generation, and look at the financial impact of all these combined factors in connection with a typical mid-sized up-stream oil and gas production field.

1. INTRODUCTION

1.1. On-Shore Oil Production

During the coming 15 years, total oil production is expected to grow from around 80 million barrels per day (bbl/d) to around 90 MMbbl/d. Today on-shore oil production accounts for 72% of the total production, and this is estimated to reach 76% by 2030.

When looking at the on-shore figures alone, today's oil production of 62 MMbbl/d will increase to around 73 MMbbl/s, representing a total increase of 11 MMbbl/d. At the same time, current existing production fields will decline from 62 to below 40 MMbbl/d by 2030. This means that on-shore oil production alone should take into production more than 30 MMbbl/d of new production capacity.

The main share of this new capacity is expected to come on-stream mainly in the Middle East and North America (shale oil). In absolute terms, North America's share will rise moderately from around 10 MMbbl/d to close to 15 MMbbl/d, while the Middle East will have the lion share of new capacity, growing to around 30 MMbbl/d in 2030.

1.2. The Middle East Region

In the Middle-East region, the oil production strategy has been based strongly on state-owned operations where national control dominates the value chain from the well to the market (National Approach). During the recent years Production Share Agreements (PSA) have been more prevalent (for example in Iraq). Large National or International Oil Company led Joint Ventures have invested in projects as concession owners and Operating Companies (OC).

National Governments in the region have taken a hard approach regarding negotiated PSA agreements, and the major part of the Crude Oil (CRO) sales price stays with the Governments. The revenues for the Operating Company in the easy access areas are typically between 5 to 10 dollars per produced barrel, and sometimes even less than 5 dollars.

The PSA price is, of course, a function of several parameters, such as the estimated size of the reservoir (MMbbl), its estimated production capacity (Mbbl/d), the accessibility and operational easiness of the field, the structure of other fees, and the taxes and licences needed. The main parameters, however, are of course the estimated Capital Cost (CAPEX) needed to develop the field, and the expected lifetime costs for operating the field (OPEX).

The PSA price level is a crucial factor for the Operating Company. The assumptions made in the cost structure during the acreage bidding rounds are far reaching, since PSA agreements can easily be valid for up to 30 years or more. The price change mechanisms in the agreements do not easily allow corrections for mistakes made in the initial costing. Normal indexations and the global CRO price typically dictate the lifetime revenue from the produced barrels.

When looking at the financial situation of PSA based oil production from an OC's point of view, the profits from developing a field can suddenly become surprisingly tight, and any change in the conditions can easily lead to a loss making project. Some recent reports of cost overruns in CAPEX, delays in site development, and too optimistically estimated OPEX costs have already sparked speculation as to the real future feasibility of such projects.

With this in mind, there has been much pressure to improve the lifetime cost picture for projects. So far this can be seen, for example, in the project development phase where the various equipment suppliers have been put under heavier pressure, both in equipment pricing and in having to accept greater responsibility regarding project execution risks.

Often, the lifetime OPEX will be about 1-2 times higher than the initial project development CAPEX. This suggests that if areas can be identified that will offer moderate OPEX cost savings or improved production volumes, such improvements could make a difference in the OC's profit revenue estimates during the existing PSA period.

In this paper we examine and analyse the power production strategies chosen for an oil field. This means both the electrical power production as well as the various pumping and compression duties normally present at the field. We'll take a look at alternative ways to produce the needed power by utilizing - if available – alternative fuels locally present at the production site. Finally, we'll consolidate these alternative strategies into lifetime CAPEX and OPEX, and compare them with today's "Industrial Standard" thinking and the conventional solutions proposed by specification teams and consultants involved in the initial PRE-FEED and FEED studies.

2. MODEL OIL FIELD DEFINITION

2.1. General

This study has been based upon a typical Middle-East oil field set-up which will be defined in the following paragraphs. The detailed results presented are specific to this particular case, but the analogy with alternative fuels and power solutions can be applied to various oil field configurations, both in Green Field developments as well as in brown field up-grades, extensions, and efficiency improvement projects. These “new” power and fuel strategies are worth being examined, especially when new fuel sources can be considered.

2.2. Oil Field Background

For the purpose of this study a generic oil field was defined. The field size chosen is a typical mid-size oil field in a Middle-East context. The basic underground parameters for the production area, including the raw oil properties, are typical for the Gulf Region. The oil field is located and operates in desert conditions. The reservoir itself is located 300 m.a.s.l and has dimensions of roughly 7 km x 14 km. The following table summarises the field properties.

Oil Field main parameters:

-Estimated Reservoir size:	1000 MMbbl
-reservoir depth:	2800 m
-CRO API Density:	32
-Water Cut:	10%
-Gas Oil Ratio:	1180 scf/bbl
-Gas Molecular Weight:	30

2.3. Oil Field Production

This size of oil field, having 1000 MMbbl of estimated oil reserves, would typically be designed for a 30 year life span. As the total raw flow from underground is gas rich, the field is designed also to produce pipeline quality natural gas. The planned ramp-up time to plateau production level is estimated to be 5 years, and the plateau production 9 years. The declining period is estimated to be 15 years. The main production related parameters are given below.

Main Oil Production parameters:

-First year production:	25 mbbl/d
-Plateau production rate:	166 mbbl/d
-Final year production rate:	30 mbbl/d

Main Associated Gas (AG) Production parameters:

-First year production:	28 MMscf/d
-Plateau production rate:	166 MMscf/d
-Final year production rate:	35 MMscf/d

2.4. Oil Field General Arrangement

The above described Oil Field is assumed to be as shown in **figure 1** below, with the following main elements being part of the new field development and contributing to the total site development investment costs (CAPEX).

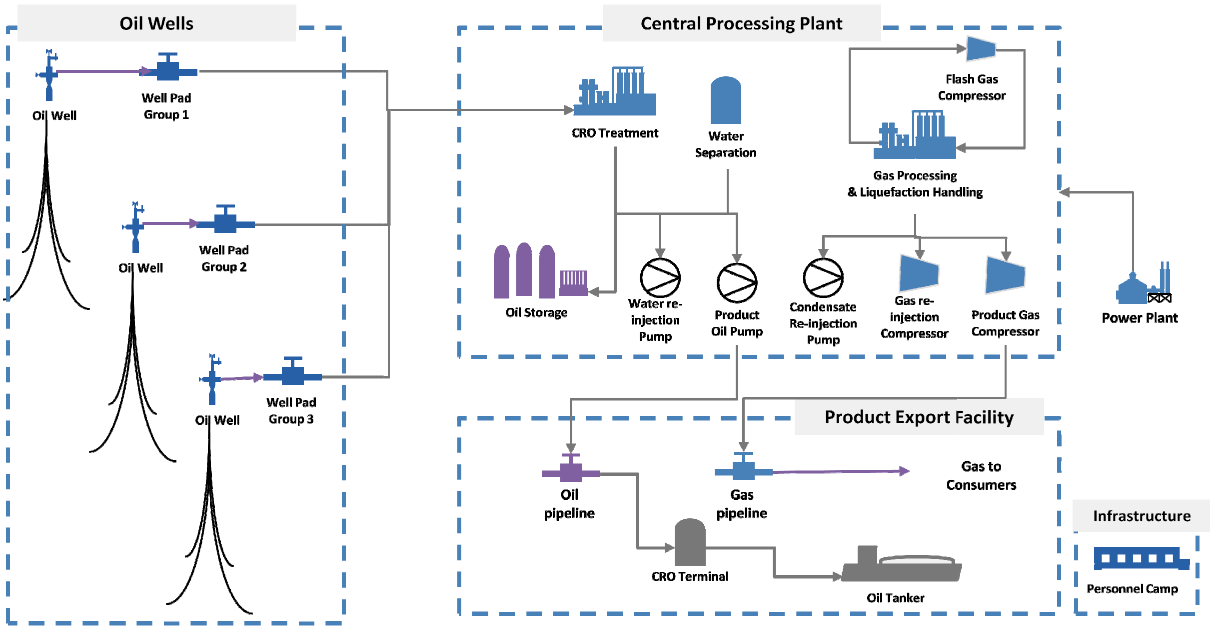

Figure 1. Main Structure of the chosen oil field with the various elements contributing to the total project development and CAPEX.

The oil field can be separated into the following main functional areas: production wells and oil pads, Central Processing Facility (CPF) including the gas processing facility, product export operations, and the general field area infrastructure and personnel facilities.

Production Wells

The production wells are located within the reservoir area. In total there are 125 individual wells to be drilled and connected to well pads and collection piping, and finally to the Central Processing Facility (CPF). As the individual wells are scattered around the entire area with the longest flow lines being around 5 km, local power production at the well pads is covered by small high speed Light Fuel Oil (LFO) fired combustion engine generating sets

Central Processing Facility (CPF)

The raw oil flow from the well pads is collected and piped to the Central Processing Facility where the raw oil flow will be processed into products and side streams. The main activity at the CPF is to separate and clean the Crude Oil (CRO) to the specification required. During this process the CRO will be separated from any sand, water, associated gases, and other impurities and toxic materials, such as H_2S.

The separated associated gases (AG) flow contains hydrocarbon molecules, which range from methane (CH_4) all the way up to the heavier molecules that do not yet form part of the stabilised CRO. The array of hydrocarbon molecules in the AG is field specific and can vary a lot, depending on the region. In this particular case the average molecular weight of the AG is around 30.

The Associated Gases can be further processed to produce either Natural Gas (methane), ethane, LPG (propane and butane), and natural gasoline in a Gas Processing Facility (GPF). If not all the AG is being processed into other products, then the remainder of the flow must be disposed of in some way at the oil field.

In the older existing fields, the most common method is to burn (flare) the left over AG. It is still done extensively, even though it is becoming more and more questionable from the environmental and energy efficiency points of view.

New fields are being designed with more acceptable methods for disposing the AG, such as injecting the gases and liquids back into the ground, or if smaller amounts are in question, to store them locally at the field and periodically transport them for disposal to, for example, refineries.

Product Export

One of the main functions at the oil field is to get the various products despatched to the refineries and customers. Typically there is local storage capacity at the oil field for various liquids from a few days' production.

CRO is normally transported via CRO pipelines with associated pumping stations, quantity measurements, and other process equipment needed. Other liquids, if produced, are often transported by tanker trucks unless the amounts are of such a magnitude that separate pipeline transportation could be viable. If natural gas is being produced it will be transported via a dedicated NG pipeline with gas compressors, measurements, and other necessary process equipment.

Infrastructure Facilities

An oil field operation needs a well functioning infrastructure to support the entire operation. This includes personnel facilities with related services, such as accommodation, meals, leisure- and hobby activities, necessary buildings, roads, transportation services, and total site security arrangements. In many cases these facilities are created from zero and can represent a significant share of the total investment scheme.

3. Side Streams from CRO treatment

3.1. General

Raw oil from the well is cleaned and separated into CRO at the Central Processing Facility. One of the side streams from the separation process is Associated Gases. In this case study, the AGs are fed into a Gas Processing Facility (GPF) for producing the maximum amount of Natural Gas complying with pipeline quality specifications. The produced NG would directly reduce the NG import from neighbouring countries or LNG from the market place

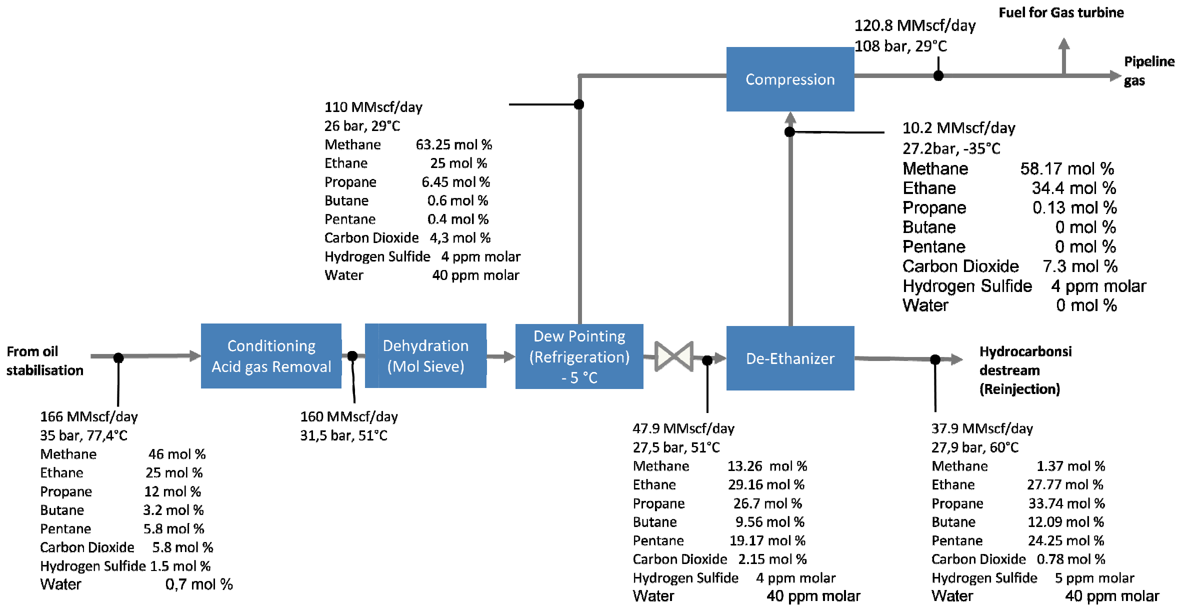

Figure 2. Gas Treatment process at a GPF to produce pipeline quality Natural Gas from Associated Gases.

3.2. Initial Associated Gas Flow

The Associated Gas flow from the CRO separation process is delivered at high pressure (35 bar) to the Gas Treatment Facility. The AG composition is as per table 1 below with some main parameters listed. The AG mass flow at this point is 166 MMscf/day

Component	Molecular Fraction [%]
Methane (CH4)	46
Ethane (C2H6)	25
Propane (C3H10)	12
Butane (C4H12)	3,2
Pentane and heavier (C5+)	5,8
Water (H2O)	0,7
Carbon Dioxide (CO_2)	5,8
Sulphur Hydrogen (H2S)	1,5

Table 1. Initial Associated Gas Analysis entering the treatment facility – the most important parameters.

3.3.Gas Treatment

The Associated Gas flow is sweetened by removing H2S and CO_2 from the AG gas stream. After sweetening, the water will be removed using a de-hydration process.

Natural Gas is extracted as pipeline quality from of the AG low. Extraction is done by means of cooling the gas via the dew point control process. The required quality will be reached at a temperature of -5 C. The NG produced will be compressed to 108 bar pipeline pressure for transportation to the receiving terminal. The amount of produced NG is 120 MMscf/day.

The left over gases (Side Streams) after NG extraction are directed to a re-injection station. There, the gases are compressed and re-injected back into the ground formation. The total amount of re-injected Side Streams, after acid removal and dehydration, is 38 MMscf/d.

Component	Molecular Fraction [%]
Methane (CH4)	1,3
Ethane (C2H6)	27
Propane (C3H10)	34
Butane (C4H12)	12
Pentane and heavier (C5+)	25
Water (H2O)	0
Carbon Dioxide (CO_2)	0,7
Sulphur Hydrogen (H2S)	5 ppm

Table 2. Side Stream Analysis after NG extraction.

3.4. Summary of Hydrocarbon balance

A total Raw Flow from the well is separated into a CRO-flow, NG-flow and Side Stream flow, as per the table below, which refers to the plateau production phase. It is assumed that during the ramp-up and declining phases, the ratios will remain the same in relation to the CRO production.

Component	Volume Flow	Unit
Crude Oil (CRO)	166	Mbbl/day
Associated Gas (AG)	166	MMscf/day
Natural Gas (NG)	120	MMscf/day
Side Streams	38	MMscf/day

Table 3. Total Hydrocarbon Flow Balance of the Raw Flow from the well.

3.5. Side Stream Handling

As the side stream flow is relatively small, the solution chosen to handle the side streams was to inject them back into the ground. In this scenario, the investment and operational cost comparison favoured a simple injection compressor station rather than building a full side stream handling process to separate the ethane, LPG, and natural gasoline for sales.

The re-injection compressor station is located within the field area. As the flow is a combination of a wide variety of hydrocarbons with a high wobbe index, it is not used as GT fuel in power generation.

4. The Power Need at the Oil Field

4.1. General

The majority of the power consumption for oil field operations comes from the Central Processing Facility (CPF). The oil pads and Personnel Facility camp have their own local power generation, which is not considered in the following chapters. The focus will be on the CPF operations, both in regard to the electrical power and mechanical power needs, including product transportation related pumping and compression.

In terms of industrial standards, the local power generation and needed mechanical drive duties for pumping and compression are carried out using Gas Turbines (GT), all of which are fuelled by the pipeline NG produced.

4.2. Central Processing Facility

The various main functions that the Central Processing Facility performs in this project set-up are: CRO Separation, Gas Processing, Water injection, Side Stream injection and product send out (CRO and NG pumping and compression into the pipeline). The illustration below indicates the CPF operations and power consumers.

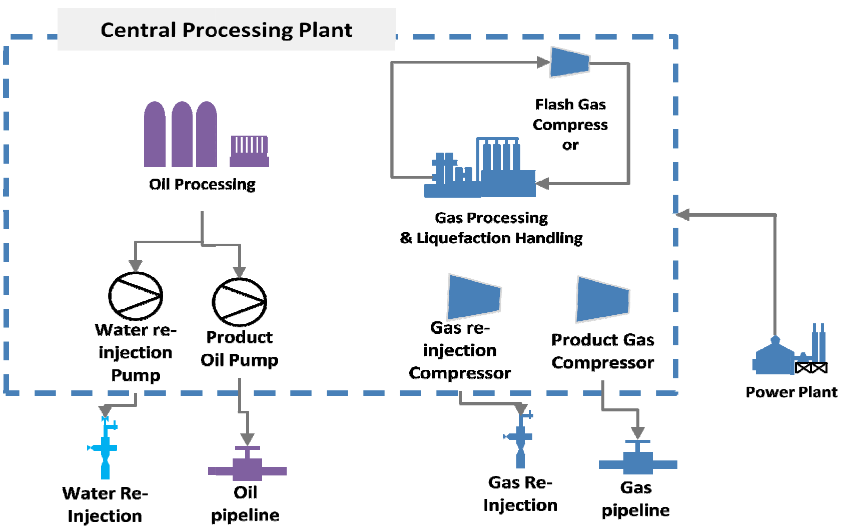

Figure 3. Power demand illustration for the CPF with gas processing showing the various power needs at the CPF.

4.3. The Power Need at the Central Processing Facility

The power demand for the various duties is normally defined during the FEED-Study phase. Large mechanical drive needs are typically realised by using electrical drives of up to 4 to 5 MW duty. Above that, the drive duty is achieved using a Gas Turbine connected directly to a pump or compressor. In this case study the various power needs at the CPF are as per table 4 below.

Duty	Duty Type	Power Need MW	Note
Power Generation	El. Power	10	
CRO product pumping	Pump, electrical	(2,7)	Included in Power Generation

NG export	Compressor, mech	10,8	
Water Injection	Pump, mechanical	10,7	
Side Stream Re-Injection	Compressor, electrical	2,3	Included in Power Generation
Flash Gas	Compressor, mech	5,4	
TOTAL		36,9	

Table 4. Power Demand at the CPF for various duties.

When looking into the above duties and the selection of power units, the actual site conditions must be taken into consideration. In this case study the maximum ambient temperature for equipment dimensioning is 55°C, which typically means a derating factor of 30% or more for a typical industrial gas turbine. As regards the power generation, the power factor, generator efficiency, and ageing factors must also be considered when selecting the units. Table 5 below shows the relationship between the needed power duty, the calculated ISO power to satisfy the power need at max. ambient conditions, and the selected power unit for ISO power. These numbers does not include any reserve units as they are not normally in operation.

Duty	Max. Power Need MW	ISO Power Need MW	Selected Unit Power MW
Power Generation	10	16,9	21,8
CRO product pumping	Electrical		
NG Product Export	10,8	15,1	15,3
Water Injection	10,7	14,9	15,3
Gas Re-Injection	Electrical		
Flash Gas Compression	5,4	7,5	7,7
TOTAL	36,9	54,4	60,1

Table 5. The Power need at the CPF vs. selected power units and related ISO powers.

From the above figures it can be seen that the maximum power need is typically around 60% of the selected power units' ISO Power, meaning that in the best case the gas turbine is operating at around 60% load. Taking into consideration the load variations with real power needs and the lifetime rump-up and declining phase, the turbines are operating with an average lifetime load of well below 50% in reality.

4.4. Power Unit Fuel Consumption

When looking at industrial gas turbines in an output range of 10 -15 MW ISO Power, the efficiency range is typically around 30%, including the 5% ISO tolerances (as the heat rate can be said to be 12000 kJ/kWh or 11373 BTU/kWh). These numbers correspond to new clean units at 100% load at ISO reference conditions at 15°C ambient temperatures.

When looking at the real operational conditions, i.e. up to 55°C ambient temperature together with unit loads below 50% of the ISO power and not clean units, it can be noted that the actual power unit efficiencies are well below 20%. In average lifetime operation, taking into consideration the ramp-up and declaiming phase of the site, the efficiencies can be as low as 15%, which is even lower than piston steam engines.

The below graph shows a selection of heat rates for industrial gas turbines as a function of max. turbine output.

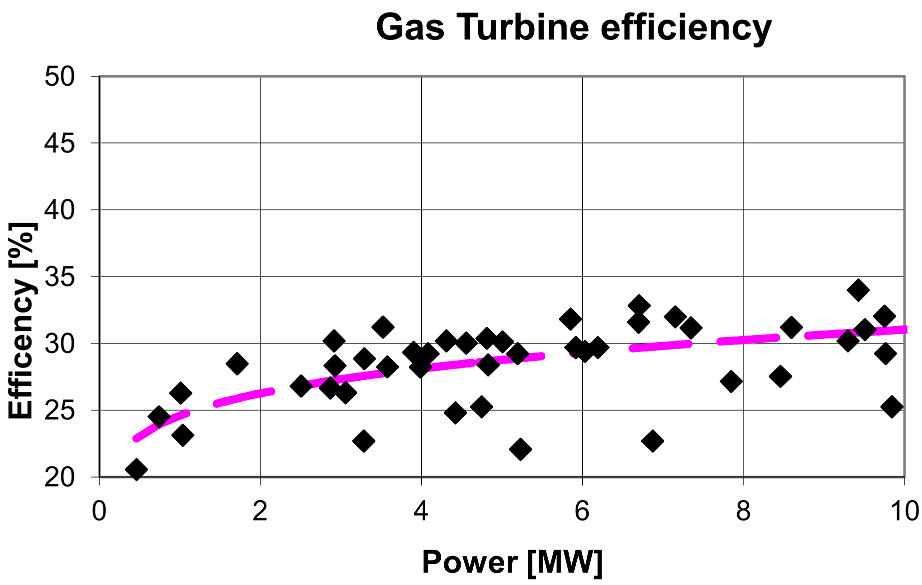

Figure 4. Typical gas turbine efficiencies in a range of 1 to 10 MW shaft ISO power (source Mechanical Drives Gas Turbines).

Gas turbine efficiency (heat rate) strongly depends upon the operational load in ratio to the maximum ISO power. Efficiency decreases rapidly as the operational load decreases. At 50% load, efficiencies are typically in the 20 to 25% range referred at shaft power. The below graph shows gas turbine efficiencies as a function of operational load for gas turbines of around 10 MW.

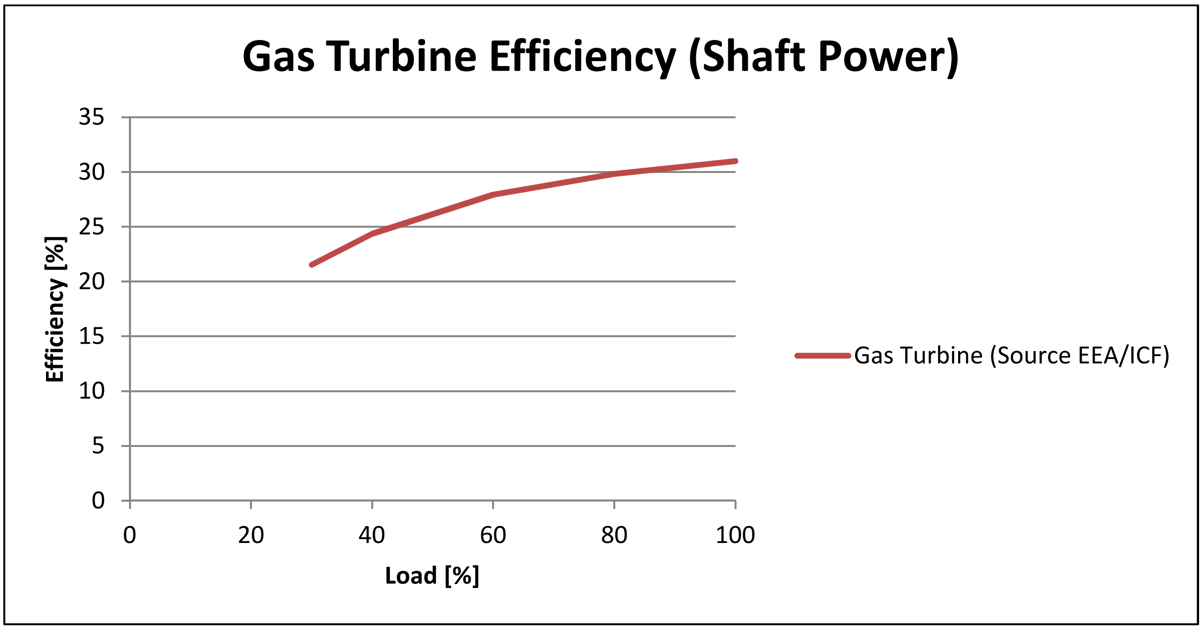

Figure 5. Typical gas turbine efficiencies as a function of operational load in a range of 10 MW shat power as a new and clean unit.

Taking the above into consideration, the study-case can be simplified into a situation whereby the total maximum power need for various duties is 36,9 MW, which will be satisfied by a gas turbine installed ISO power of 61,1 MW at the shaft. Taking into consideration the generator efficiencies and power factors, and the average effect of the dirtiness level, the efficiency is in the range of 20% (heat rate 18.000 kJ/kWh or 17.060 BTU/kWh) at the plateau max. power need.

In the table below, the power needs for both a maximum situation and the lifetime average weighted values are presented. A full load situation refers to the plateau oil production phase which occurs over a period of nine years. In the lifetime fuel calculation models, the ramp-up and production declining phases have been simulated with correction factors, both for the power need and for reducing the operational load of the installed power units. The last column presents the actual lifetime average operational load for the power units.

Duty	Max. Power Need MW	Lifetime average Power Need MW	Selected Unit Power MW	Lifetime average operational load %
Power Generation	10	7	21,8	28,3
Mechanical Drives	26,9	16,14	39,3	41
TOTAL	36,9	23,14	61,1	37,8

Table 6. Maximum Power need and average lifetime Power Need at the CPF vs. selected power units at ISO powers.

For lifetime average efficiencies, taking into consideration the ramp-up and declining phases, the following calculations have been made using a lifetime average efficiency for power generation of 18% and for mechanical drives 19% (or heat rates 20.000 and 18.950 kJ/kWh or 18956 and 17.961BTU/kWh)

Duty	Lifetime average Power Need MW	Lifetime average Unit Efficiency %	Fuel Power at average power need MW	Lifetime average gas consumption MMscf/day
Power Generation	7	18	38,9	3,10
Mechanical Drives	16,14	19	84,9	6,76
TOTAL	23,3		123,8	9,86

Table 7. Average lifetime fuel consumption with average efficiency.

The total NG consumption as GT fuel can be calculated from the above. The average lifetime daily consumption of 9,86 MMscf per day multiplied by an average 350 days per year and a lifetime of 30 years equals around 103530 MMscf in total.

5. An Alternative Solution for Power Needs

5.1. General

The previous chapter described a standard "industrial solution" as an oil field power scheme. It is typically based on low efficiency industrial gas turbines operating at lifetime average loads of well below 50%, thus having typical lifetime average efficiencies of between 15 and 20%.

An alternative solution to provide the necessary power is to utilise combustion engines. Large bore medium speed heavy duty liquid fuel, gas fuel, or dual fuel engines can provide significant benefits in terms of fuel consumption and multi-fuel capabilities.

5.2. The Combustion Engine in Power Generation

Large bore combustion engines are well established as power plant prime movers. The largest power plants today are up to 600 MW with multiple 20 MW units. In the oil and gas industry, the use of large bore combustion engines is fragmented, especially in the Gulf region where gas turbines have been widely used.

For this case-study a heavy duty 8,9 MW ISO output, 750 rpm unit with a piston diameter of 32 cm was selected. The unit is a so called Gas Diesel (GD) engine with dual fuel capability – being able to operate both on various gases and/or liquid fuels, in this case Associated Gases and Crude Oil. This means that the unit can operate on Crude oil directly from the CPF in case there is an interruption to the gas feed.

The GD engine principle is specifically designed for rough conditions and is capable of utilising various fuel qualities, both for gas and liquid. The gas quality demand in particular is very wide and, for example, Associated Gases or typical side streams from the Gas Processing Plant can be normally used as fuel for the units. In selected fuel gases even H2S up to 2000 ppm if so specified is acceptable.

		20V32GD
Cylinder Bore	mm	320
Speed	rpm	750
Shaft Power	kW	8 900
Electrical Power, 50 Hz	kWe	8 550
Heat Rate	kJ/kWhe	8181 (7813)*
Electrical Efficiency	%	44,0 (46,0)*
Shaft Efficiency	%	45,5 (47,5)*
Generating set dimensions:		
Length	mm	12 660
Width	mm	3 300
Height	mm	4 243
Weight	ton	132
Engine dimensions:		
Length	mm	9 276
Width	mm	3 233
Height	mm	4 139
Weight	ton	89

Figure 6. Main characteristics of a 20 cylinder 20V32GD dual fuel engine.

5.3. Fuel Consumption Characteristics

Medium speed combustion engines naturally have a relatively high shaft efficiency. Typically, the values at ISO conditions are well above 45% (heat rate less than 8000 kJ/kWh, or 79582 BTU/kWh). For engines, the standard ISO conditions have been set at 25°C (gas turbines at 15°C) and the derating due to ambient temperature starts at 35°C. At a 55°C ambient temperature, the units have been derated by about 10% of the output, meaning that the ISO output of 8900 kW unit would still provide 7900 kW at the shaft.

As an alternative solution to provide the needed power for the CPF, a fully electrified system was introduced. This means that a larger central power plant will be constructed and all the mechanical drive duties will be executed using electrical drives. Thus the total power need would be supplied through a central power plant having a (n+2) configuration with combustion GD engines. The fuel supply would be taken from the NG processing plant side streams and CRO would be used as a back-up fuel.

When looking at the total power need for each duty, taking into consideration the power increase due to electrical drives, and considering the combustion engine's small ambient derating, the engines in operation needed in order to satisfy the maximum demand situation is according to the below table.

Duty	Max. Power Need MW	Electrified Max. Power Need MW
Power Generation	10	10
Mechanical Drives	26,9	29
TOTAL	36,9	39

Table 8. Selection of combustion engines for CPF Power need as a fully electrified solution..

As the max. engine electrical power at 55°C ambient conditions is 7900 kWe, and taking into consideration about 5% of the power plant's own parasitic consumption, the needed number of units will be six (6) units in operation, providing 6 * 7,9 – 4 MW=43,4 MW of maximum net power available for the oil field operations. This allows a margin of about 10% for load changes.

The engine efficiency curve vs. the operational load is relatively flat compared to gas turbines. At full load during a plateau situation, the engine is operating at 80% load compared to its ISO power. This is a much higher load than in the same situation with the gas turbines (see table 5 above). Below, a comparison of efficiencies (heat rates) between a combustion engine and a gas turbine as a function of operational load, is given.

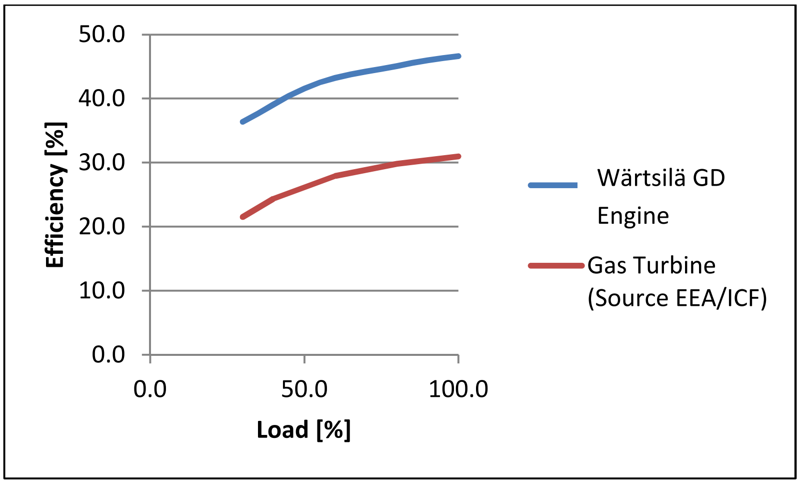

Figure 7. Combustion engine vs. gas turbine efficiencies as a function of load in a 10 MW range of shat power.

In addition to high partial load efficiency, there is another important benefit in the electrified solution, namely multi unit operation. This principle allows an optimal number of units in-line to be always operating, shutting off engines when they are not needed. By this principle the units will be running at as high a load as possible, thereby also maximising the plant efficiency in low load situations. This fact is especially important during the oil field's ramp up and declining years when the needed power is much less than the designed maximum power need. This in fact means that the lifetime efficiency of the engine based solution does not suffer at all and the average lifetime coefficient is one (1).

This concept also allows a stepwise investment of the power plant through modular sections by extending the plant as and when needed in line with the ramp-up of the oil field's production.

Duty	Gas Turbine	Combustion Engine
Total Power Need	36,9 MW	43 MW
Lifetime Average Power Need	23,14 MW	28,82 MW
Installed ISO Power	61,1 MW	53,4 MW
Load Factor (LF)	60	80
Lifetime average LF	37,8	90
Lifetime average efficiency	20%	42%
Lifetime gas consumption MMscf	103530	57337

Table 9. Summary of the lifetime load and fuel consumption for a Combustion Engine and a Gas Turbine.

When calculating the equivalent gas consumption for combustion engines from the above, the average lifetime gas consumption (average lifetime fuel power 68,6 MW) is 5,46 MMscf per day. This, multiplied by in average of 350 operating days per year and a lifetime of 30 years, equals to around 57.337 MMscf in total. This is more than 40% less fuel input compared to a standard industrial solution based on Gas Turbines.

6. Cash Flow Analysis of an Oil Field

6.1. General

The first initial simple cash flow analyses are typically made during the Pre-Feed phase of a planned development. At that point the key parameters needed are the total recoverable reservoir size, the estimated total Capex, the estimated lifetime Opex, and an assumption for the sales price of products to be delivered to the market.

In this case study the production parameters were given in chapter 2.

The main values were as follows:

Oil Field main parameters:

-Estimated Reservoir size:	1000 MMbbl
-Lifetime of the development:	30 years
-Operational days per year:	350
-CRO plateau production rate:	166 Mbbl/d
-NG plateau production rate:	120 MMscf/d

6.2. Capital Cost of the Development

The below Capex estimation is for a total green field development in the conditions as described in Chapter 2. The cost estimation is assumed to be within a window of -20 - +40% accuracy.

	Capex Estimation Million USD Gas Turbines	Capex Estimation Million USD Combustion engines
Oil wells and pads	600	600
CPF	500	540
Export Operations	350	350
Infrastructure	250	250
TOTAL	1.700	1.740

Table 10. Estimation of the Total Capital Cost of the Oil Field Development for two cases, one for gas turbines and one for combustion engines.

In the above cost breakdown two cases are identified, one based on gas turbines as the power source, and the other based on combustion engines as the power source. In the combustion engine case it has been assumed that the electrical drives are on the same price level as similar gas turbine drives. The cost addition is derived from the larger power plant to be constructed.

The Export Operations item includes product pipelines to the export terminals for CRO and NG. The distance between the CFP and the terminals is 100 km. The Infrastructure item includes a main road between the infrastructure facility and the production area.

The above presented total Capex presented above is the estimation for a facility capable of producing the plateau capacity.

6.3. Lifetime Operational Cost of the Development

The Operational Costs (Opex) during the lifetime of an oil field development project in this size range are typically more than the initial investment. This is the case here as well. The table below presents a summary of the Opex costs considered in the study; the main items being personnel costs and various costs related to the inspection and maintenance of the production system. The power unit operation and maintenance of the power unit is also included in these two items.

	Lifetime Opex Estimation Million USD
Operating Personnel	400
Inspection and Maintenance	500
Logistics and consumables	350
Wells	250
Insurance	300
Field and Project costs	300
TOTAL	2.200

Table 11. Estimation of the Total Lifetime Operational Cost of the Oil Field Development.

6.4. Cash Flow Analysis

In the following analysis, a simple cash flow comparison is made between two power generation strategies for the oil field. The environmental factor in terms of the CO_2 footprint has also been highlighted at the end of the chapter. The two cases are as follows:

1. A standard industrial solution where the power generation and mechanical drives have been executed using gas turbines, as described in chapter 4 above. The fuel is taken from the pipeline natural gas flow produced, thus reducing the amount of saleable natural gas.
2. An alternative solution is based on combustion GD engines with a single central power plant, as described in chapter 5 above. The plant will feed both the general power needs for the CPF, as well as the larger electrical motors used as drivers for the various mechanical pumping and compression duties. The power units will use side streams as fuel, thus reducing slightly the side stream injection needs. CRO can be used as a back-up fuel for the units if there are interruptions to the side stream flow.

The main comparison analysis has been made both for a National Approach, as well as for a Production Share Agreement (PSA) based on the Operational Company Approach.

Typical international market prices for CRO production have been used for the product pricing. In this study, for simplicity sake, 100 USD/bbl has been used. For the produced NG, a price range between 4 and 10 USD/MMBTU has been given to provide an understanding of a possible “low pricing” policy and the market price level income. As an example, LNG is sold widely on a FOB basis of around 15 USD/MMBTU in the eastern hemisphere markets.

National Approach

In the National Approach, the local National Oil&Gas Company controls the total value chain, thus seeing the CRO sales at a market price level.

The table below shows the simple lifetime cash flow from a National Approach point of view. Monetary values shown are in USD and the calculations do not consider any interest payments or discounting the net present values of future revenues. Neither does it assume any indexation of the sales prices nor the opex costs during the lifetime of the project. The main aim is to indicate the effect of using side streams as fuel with a higher efficiency prime mover technology.

	Industrial Standard Solution Gas Turbine based solution Million USD		Alternative Solution Combustion Engine Power Plant Million USD	
	NG price 4 Million USD	NG price 10 Million USD	NG price 4 USD Million USD	NG price 10 Million USD
Sales Income for CRO	100.000	100	100.000	100.000
Sales Income for NG	4.626	11.565	5.040	12.600
Initial Investment Capex	1.700	1.700	1.740	1.740
Operational Cost Opex	2.200	2.200	2.200	2.200
TOTAL	100.726	107.665	101,100	108.660

Table 11. Lifetime cash flow of the selected cases in a National context where a single entity earns the full income

In the above table, the lifetime cash flow difference comes mainly from the greater NG sales resulting from the fact that the alternative solution is using side streams (in this case "waste") as fuel, thus leaving the full amount of NG flow produced for revenue generating product sales.

From the above it can be concluded that for the alternative solution, the higher the NG sales price, the greater is the income. At the 10 USD price level, the lifetime extra income is in the range of one billion USD, making an additional margin for the operations of more than 30 million USD per year compared to the conventional GT solution.

In other words, the production site can supply 9,86 MMscf/day more NG to the pipeline when using a technology that can utilize side streams as fuel.

If the national gas supply partially depends on imported LNG, then the value of this additional gas is the same as the imported LNG plus the re-gasification cost. For example, 15 USD/MMBTU + 1 USD for re-gasification adds up to 16 USD/MMBTU. In this case the technology change would create savings of 55 million USD annually, meaning that the simple payback time for the additional investment for the central power plant is about one year.

PSA Approach

In the PSA approach, the CRO income is based on a negotiated price for the produced CRO. This can vary a lot depending on the geographical location and other factors. In the M-E region, PSA agreements have been reported as being as low as 2 USD/bbl to more than 10

USD/bbl. In this study a PSA CRO price for the Operating Company was assumed to be 7 USD/bbl.

The big question as regards the PSA Agreement is how the associated gases have been treated. If we assume that the gas revenues will be split 50/50 between the resource owner and the Operational Company, then the cash flow coming from the NG sales can be summarised at price levels of 2 and 5 USD/MMBTU respectively. This would result in the following lifetime cash flow situation for the Operating Company:

	Industrial Standard Solution Gas Turbine based solution Million USD		Alternative Solution Combustion Engine based Power Plant - Million USD	
	NG price 2 Million USD	NG price 5 Million USD	NG price 2 Million USD	NG price 5 Million USD
Sales Income for CRO	7.000	7.000	7.000	7.000
Sales Income for NG	2.313	5.782	2.520	6.300
Initial Investment Capex	1.700	1.700	1.740	1740
Operational Cost Opex	2.200	2.200	2.200	2.200
TOTAL	5.413	8.882	5580	9.360

Table 12. Lifetime cashflow of the selected cases from an Operational Company point of view based on a PSA Agreement.

From the above results it can be seen that the total lifetime cash flow is somewhat lower for an Operational Company operating under a PSA Agreement. The 100 billion lifetime revenue has become less than 10 billion dollars.

It was said earlier that the NG sales revenue will be split 50/50 between the Owner and the Operating Company. This split principle is shown in the NG sales income above. It can be seen that at a gas price of 10 USD (5 USD for OC), the gas revenue is in the same magnitude as the CRO revenue, which means that the NG sales easily become as important a goal as the CRO sales.

When looking at the lifetime cash flow between the two technical solutions (GT and combustion engines), it can be seen that the additional revenue coming from the extra NG sales is between 210 and 518 million USD during the lifetime at the respective 2 and 5 USD NG prices. When looking at this on an annual basis, the additional profit is between 7 to 17,2 million USD per year. The increase in the annual profit is nearly 6% at a 5 USD PSA agreement price.

If looking again at the gas savings from the LNG market price and the 50/50 share of income points of view, then the annual savings would be 27,5 milion USD.

These results can be achieved by an additional one time investment of around 40 million USD during the initial project construction phase. It can be directly seen from the numbers that the **simple pay back time for the centralised power plant solution based on combustion engines is less than three years with an NG price of 5 USD**.

6.5. Environmental Considerations – CO_2 Footprint

In the traditional Oil and Gas industry, power needs are typically covered using industrial gas turbines having relatively low efficiencies in the range of a max. of 30% as new and clean machines in ISO ambient conditions and full power operation. Under actual conditions and operational situations (see chapter 4 for explanation) the GTs often operate at less than 50% load and with efficiencies of well below 20%, and real average lifetime efficiencies of as low as 15 to 17% can be seen.

The lower the efficiency of the power unit, the more fuel it burns to generate the needed power. At the same time, the amount of emitted CO_2 gases is linearly dependent upon the amount of fuel burned. By calculating the total fuel used, and thus the amount of CO_2 emitted during the lifetime of the oil field operations, a CO_2 Footprint per produced barrel of CRO can be ascertained.

CO_2 Difference by Efficiency

In the below comparison the average lifetime CO_2 emissions for the two above mentioned technical power solutions have been calculated. For fuel consumption calculations, the loads and efficiencies as defined in chapter 4 and 5 respectively for the GT and combustion engine solutions have been used.

In the results below, the power needs and power unit characteristics, as described in the previous chapters for the oil field in question, have been used. CO_2 Footprint calculated takes into consideration the on-field power generation related CO_2 only.

	Units	CO_2 Footprint Gas Turbine	CO_2 Footprint Combustion engine
Lifetime average efficiency	%	18 and 19	42
Fuel Power (thermal)	MW	123,8	68,6
Gas consumption	MMscf/d	9,86	5,46
Annual average CO_2 Production	Ton/year	264.270	146.405
Lifetime CO_2 Production	Ton	7.928.100	4.392.167
CO_2 Footprint per BBL of CRO	kg/bbl	7,9	4,4

Table 13. Results of the CO_2 production and CO_2 Footprint per produced barrel of crude oil for both technical solutions.

From the above it can be seen that the technology chosen in order to cover the various power needs has a strong effect on the CO_2 footprint per CRO barrel produced. By utilizing high efficiency combustion engines, the CO_2 footprint can be potentially reduced by more than 40%.

A CO_2 Footprint reduction of this magnitude can be considered as being an extremely big step-change in a typical industrial practice. It is the single largest change that can be achieved by simply taking into use a more efficient power technology; one that has for a long time already been utilized in the power generation industry because of the fuel cost savings and the lower CO_2 emissions.

CO_2 Difference when utilizing Flare Gases

In the case of similar oil production where the side streams would be flared instead of re-injected into the ground, then additional CO_2 reductions can be achieved when compared to above described situation. In this case there are two major CO_2 sources at the site: 1. Power generation by Gas Turbines burning saleable NG in large quantities, as shown in the above (table 13), and 2. The entire side stream flared into CO_2 without any benefit being derived from the "waste fuel".

If the "waste fuel (flared side stream)" were to be utilized as fuel for power generation using combustion engines, the potential CO_2 reduction in relation to the GT - generated CO_2 would be 100% (see the above case with a potential reduction of 44%). The combustion engines would take part of the side streams that are flared and use it for fuel. In this way, the total side stream generated CO_2 will remain the same, even though part of it has been used for generating power by the combustion engines.

In the third column of the table below, a situation with GT's fuelled with NG as the power generation technology, and with all side streams being flared is shown. In the alternative solution (column 4) a CO_2 balance is given in the case where the combustion engines are generating the power by utilizing side streams as fuel and leaving all the NG for revenue generating product sales. The left over side stream is still flared.

	Units	CO_2 Footprint Gas Turbine	CO_2 Footprint Combustion engine
Natural Gas Usage			
NG Fuel Power	MW	123,8	0
NG Gas consumption	MMscf/d	9,86	0
Annual average CO_2 Production	Ton	264.270	0
Lifetime average CO_2 Production	Ton	7.928.100	0
Side Stream Usage			
Side Stream Fuel Power	MW		68,6
Side Stream Gas consumption	MMscf/d		5,46
Annual CO_2 Production	Ton		146.405
Lifetime CO_2 Production	Ton		4.392.167
Flare Gas Balance			
Plateau Flare Fuel Power (Thermal)	MW	1160	
Annual CO_2 Production	Ton	1.375.000	1.228.595
Lifetime CO_2 Production	Ton	41.277.000	36.884.833
Site lifetime CO_2 Production	**Ton**	**49.205.100**	**41.277.000**
CO_2 Footprint per bbl of CRO	**kg/bbl**	**49,2**	**41,3**

Table 14. The CO_2 Footprint when utilizing side streams as fuel instead of flaring.

Since environmental issues are gaining increasing attention, even in the Oil&Gas industry, it can be noted that high efficiency power units can achieve considerable reductions in the production of CO_2. If the existing flare gases were to be used for power generation fuel, then even national level CO_2 balances can be improved. This is possible by taking into use high efficiency large output combustion engines with multi-fuel capabilities that include LFO, HFO, CRO, and associated gas.

7. CONCLUSIONS

Today, a large share of the world's up-stream oil & gas industry operates its power production units ineffectively by utilizing high quality (valuable) fuel in low unit efficiencies. In many production fields, lifetime system efficiencies as low as 15 to 20% can be seen, which would be totally unacceptable in the utility power industry, where the efficiencies with modern equipment reach 50% and higher.

The reasons for this situation are many: historical, technical, and a closed mindset regarding new technologies. Old specifications and the complex player structure in the value chain all contribute to this resistance to change and the acceptance of new solutions into the industry.

Some progress can, however, be seen today. The fact that "there is no free fuel in this world" is already established, as is the fact that it makes sense to consume less at the production site and to sell more to the customers in order to generate more revenues. The environmental aspects are also starting to have a more important role. A barrel of oil produced with less CO_2 can, in the near future, be a much more attractive commodity than a more CO_2 intensive barrel. Perhaps in the future there will be separate classification and pricing mechanisms for "Low CO_2 Footprint CRO" and for "Conventional CRO", with the low CO_2 content of course giving better prices.

In the above exercise it was demonstrated that by utilizing high efficiency multi-fuel combustion engines considerable improvements in project lifetime revenues can be achieved. This can be realised by:

1. utilizing technologies that consume less fuel (higher efficiencies) and
2. being able to use lower quality (sometimes waste flow) side streams as fuel.

When looking at this case study from a National Approach point of view, annual profits can be improved by 55 million USD, since, more expensive LNG purchases are reduced.

From an Operating Company point of view, when operating under a Production Share Agreement (PSA) the additional revenues can be even more than the revenues from the CRO in the agreement. This can be a game changer in certain situations, making unprofitable projects interesting for Operating Companies if the gas production related revenues can be considered as being part of the total profit. If the additional gas would be valued at 5 USD for the OC, then the annual profits would improve by nearly 6%, which can in certain situations nearly double the profit.

The exercise also demonstrated huge possibilities in CO_2 emissions reduction. Thanks to their higher efficiency, CO_2 production can be reduced by more than 40% if combustion engine technology would be used. When using flare gases as fuel, CO_2 production would be reduced by 100% compared to the CO_2 produced by GTs in a conventional project set-up.

In conclusion it can be said that a change of mentality within the oil & gas industry that would allow new solutions and technologies to be accepted represents a win-win solution for every player in the value chain, not forgetting the environment, which would probably be the biggest winner.

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