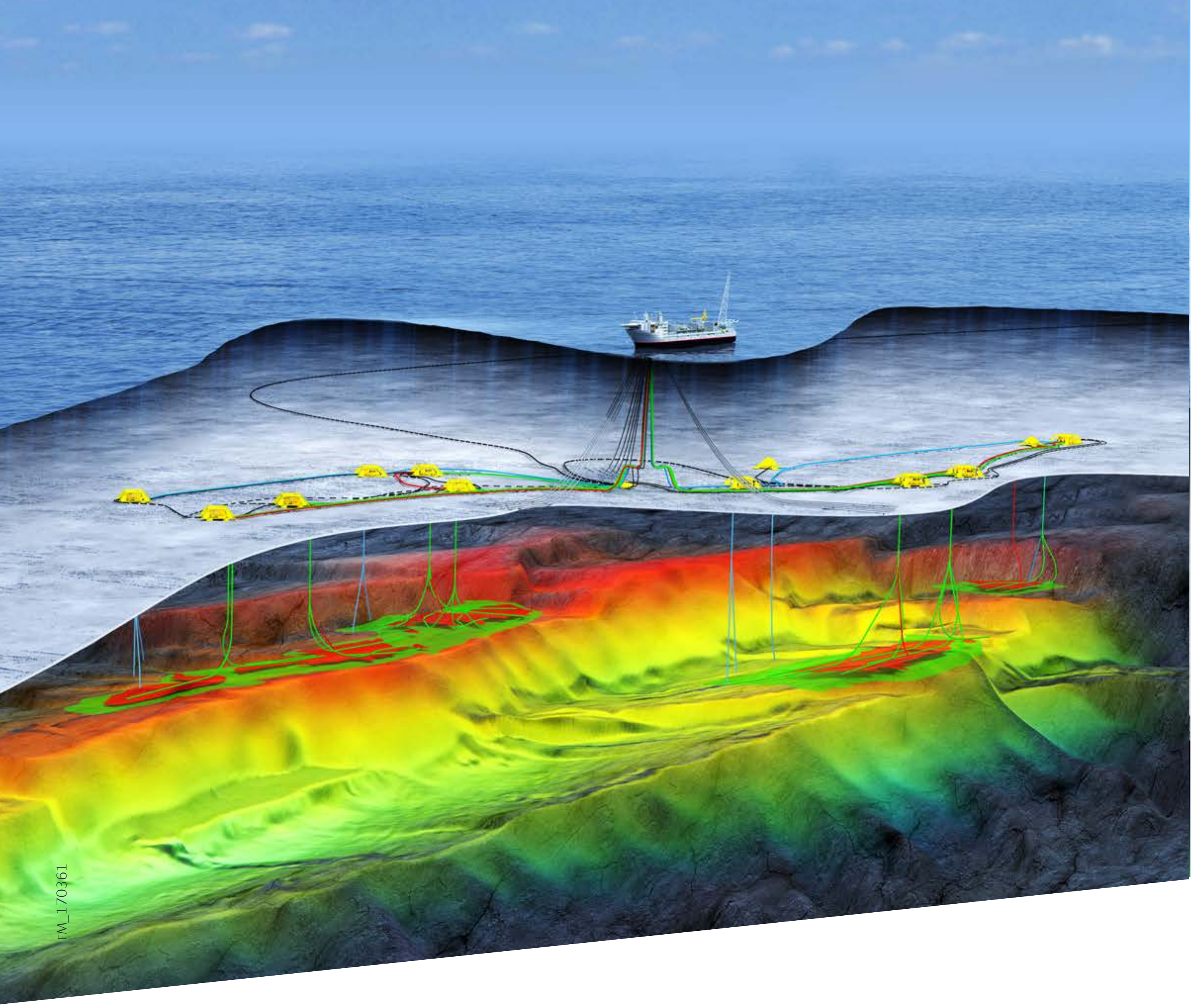
PL532 Johan Castberg
Plan for utbygging og drift

Power Concept Selection Summary Report



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1 Executive summary

The purpose of this document is to summarize facts on the different power concepts that have been evaluated towards a power concept selection decision planned for 23rd of June 2016.

1.1 Power concepts

The current energy solution (Base case - Case 0a) is offshore power- and heat generation using two gas turbines for the electrical consumers and one for direct drive of the gas compressor train, where waste heat recovery units are installed on all three turbines to provide required process heat.

An overview of all evaluated power concepts are given in the table below.

Table 1-1 Power concept matrix

			Comments
		Locally produced power and heat	
Case 0	a	Offshore gas turbines	**Base case**
	b	Offshore gas turbines Prepared for future HVAC import for electrification of electrical power consumers	
		Electrification of electrical power consumers	
Case 1	a	Power from shore HVDC Separate power host for conversion into HVAC on the field	
	b	Power from shore HVAC 50Hz shunt reactors/ series capacitor	
	c	Power from shore HVAC 50Hz shunt reactors/ STATCOM	Not feasible
	d	Power from shore HVAC low frequency	High cost – high losses
	e	Hywind / Offshore gas turbines HVAC	
		Electrification of electrical power consumers and gas injection train	
Case 2		Power from shore HVDC Separate power host for conversion into HVAC on the field	
		Electrification of electrical power consumers, gas injection train and heat demand	
Case 3		Power from shore HVDC Separate power host for conversion into HVAC on the field	

1.2 Energy efficiency

The current energy and power solution (base case), Case 0a, gives high energy efficiency due to the utilization of the waste heat from the turbines, in average 64%.

For the evaluated power from shore cases the energy losses from electricity transfer from Hyggevann (Hammerfest) to the FPSO are high, in average 20% for the HVDC/HVAC cases and 38% for the HVAC LF case.

Energy efficiency and CO_2 intensity numbers for all evaluated concepts are given in the table below.

Table 1-2 Energy efficiencies and CO_2 intensities

(Average over the lifetime)	Energy efficiency (%)	CO_2 intensity* (gCO_2/kWh)	CO_2 intensity* (kg CO_2/boe)
Case 0a-0b	64	325	14.1
Case 1a-1c	79	198	8.6
Case 1d	73	198	8.6
Case 1e	77	271	11.8
Case 2	82	106	4.6
Case 3	80	NA	NA

*Assuming electricity is 100% green

1.3 Environmental impact

Pöyry and Thema Consulting group have been engaged to evaluate the net global environmental effect of electrification of JC. The analyzes show that the local JC emissions reduction will be offset by an increase in CO_2 emissions from the power sector in Europe since electrification of JC will reduce electricity exports from Norway. Pöyry estimates low net global effects mainly related to that the marginal increase in energy demand mainly will be covered by coal and gas power plants. Thema has a more optimistic view; they believe that the marginal increase in energy demand will be covered by a higher portion of renewables as the market has time to adapt to the demand from JC. The net global effect is however still significantly lower than the local effect.
Local and net global CO_2 reduction numbers is given in the below table.

Table 1-3 Local and global CO_2 reduction

	Local CO_2 reduction (ktonn/yr)	Local CO_2 reduction (Mtonn)	Net global CO_2 reduction *PÖYRY* (Mtonn)	Net global CO_2 reduction *THEMA* (Mtonn)
Case 0a-0b		-	-	-
Case 1a-1c	104	3.1	0.8 – 1.0	1.9 - 2.4
Case 1d	104	3.1	0.8 – 1.0	1.9 - 2.4
Case 1e	44	1.3		
Case 2	182	5.5	0 – 0.9	3 - 4

Case 3	270	8.1	-1.4 – 0.1	3.8 – 5.6

1.4 Quantitative power concept evaluations

CAPEX, OPEX, production efficiency, production, CO_2 emissions, electricity cost, etc have been established for all cases in order to enable economic analyses of the different power concept alternatives. Key numbers are presented in Table 1-4.

Table 1-4 Costs and economy

2016NOK	Delta Capex (BNOK)	Delta Opex** (MNOK/yr)	Abatement cost*** 8% discount rate (NOK/tonnCO_2)	Delta NPV **** 8% a.t. (MNOK)	Delta **** BE (USD/bbl)
Case 0a*	57.5	1 572	-	12 360	44
Case 0b	0.05	0	-	-10	0
Case 1a	7.6	210	10 500	-1 900	6
Case 1b	4.0	120	6 500	-2 150	6
Case 1c	NA - not feasible				
Case 1d	NA - high cost/losses				
Case 1e	2.4*****	40	7 600	-600	2
Case 2	10.8	300	8 700	-3 650	11
Case 3	12.7	430	7 150	-4 250	13

*Reference –actual numbers, not delta numbers or reduction numbers
** Including CO_2 and electricity cost
*** Assuming power from shore is green energy
**** One year delay of DG4 applied on Case 1b, 2 and 3
****** Note, the FPSO costs are underestimated as they are based on that all required modifications are made onshore as part of the main project

The current base case power concept shows the highest NPV and lowest breakeven. None of the alternative power concepts show competitive abatement costs. A break-down of the abatement cost is given in the figure below, showing that CAPEX is the main contributor to the high abatement cost level.

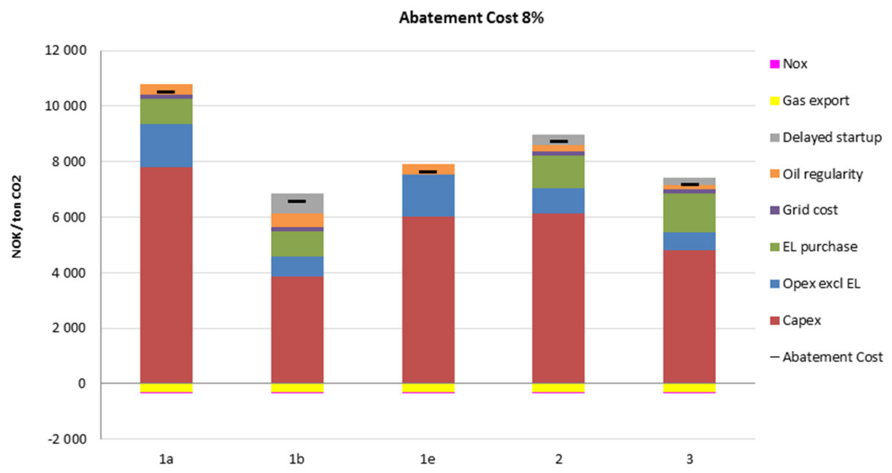

Figure 1-1 Abatement costs at 8% discount rate

1.5 Qualitative power concept evaluation

A qualitatively evaluation of the power concepts has been performed.

For each evaluation criteria the concepts are ranked against each other and given a colour code. The colour categories are:

- **Dark blue colour:** Huge opportunity, will result in huge improvement
- **Light blue colour:** Moderate opportunity, some improvements
- **Green colour**: OK / acceptable, i.e. no special problems are foreseen
- **Yellow colour**: Moderate weakness. Can be improved / resolved without large effects
- **Red colour**: Huge/large weaknesses. Will imply large effects.

Table 1-5 Qualitative concept evaluation

Main qualitative selection criteria	Case 0		Case 1					Case 2	Case 3
	a	b	a	b	c	d	e		
Safety									
Environment									
Working environment									
Reservoir uncertainty									

Area upside flexibility									
Technical fit for purpose									
Execution									
Ripple effects/local content									

Comments to main qualitative differences;

Safety;

- All cases are acceptable

Environment;

- The ranking used represents local reduction level of CO_2 emissions

Working environment;

- The ranking used represents the reduction in noise level on the FPSO

Skrugard/Havis/Drivis reservoir uncertainty;

- Due to the extra gas injection, the gas cap will expand and the optimal location of the producers will be somewhat deeper than planned for in the current base case. It is considered a reasonable assumption that the wells can be optimized for each case in order to maintain the production profile and recoverable reserves

Area flexibility;

- The ranking used represents the expected use of future areas and spare riser slots, ref section 3
- The changes related to future areas for Case 0b and Case 1e is still evaluated to satisfy the intention with these areas, e.g. enable future tie-backs in the area

Technical fit for purpose;

- The ranking used represents the level of technology maturity and need for qualification, ref section 3

Execution;

- The ranking used represents the level of FPSO modification required and schedule risk connected to technology qualification, ref section 3 and 5
- For Case 1e the applied colour is based on an assumption that Case 0b is selected in June 2016, while the Hywind wind park is selected later upon successful technical qualification. That means that production can be started-up 2022 and that the larger part of FPSO adjustments for Case 1e needs to be taken as a modification project after start-up

Ripple effects/local content;

- The ranking used represents the level on expected investment in onshore facilities and future operation

2 Introduction

2.1 Purpose

The purpose of this document is to summarize facts on the different power concepts that have been evaluated towards a power concept selection decision planned for in 23rd of June 2016.

2.2 Background

The Storting has decided that all new field developments on the NCS shall investigate if power from shore is relevant. An overview of both the amount of energy and cost required to supply the field installation with power from shore instead of using gas turbines offshore shall be established.

The Norwegian Government has recently committed to reduce the climate gas emission with 40% within 2030 compared to the emission level in 1990. In the sector subject to EU's quota system Norway shall contribute to an EU emission reduction of 43% within 2030 compared with 2005. CO_2 emissions from the NCS petroleum industry is part of EU's quota system. The price of a CO_2 quota is at present approximately 75 NOK/tonnes CO_2.

On the NCS there is in addition a CO_2 tax which was introduced by the Storting in 1991. This tax has in general increased the industry's focus on energy efficiency measures, resulting in relatively low CO_2 emissions from the petroleum industry on the NCS compared with others. In 2015 the NCS CO_2 tax is 427 NOK/tonnes CO_2. The sum of the NCS CO_2 tax and EU CO_2 quota is then at present approximately 500 NOK/tonnes CO_2. It is expected that the CO_2 quota price will increase as a result of the EU ambitions, however the Norwegian Authorities has indicated that the combined quota and tax cost on the NCS will be kept at today's level by adjusting the CO_2 tax.

A frequently utilized method for quantifying the competitiveness of a climate measure is the abatement cost. The abatement cost formula given in Figure 6-1 is utilized by both the Industry and Authorities across different types of Industries and sectors. In the report "*Kunnskapsgrunnlag for lavutslippsutvikling*"(2014) published by *Miljødirektoratet* several potential measures for different sectors are highlighted using the following definitions on the abatement costs; Low < 500 NOK / tonnes CO_2; Medium: 500 – 1000 NOK/tonnes CO_2; High >1500 NOK/tonnes CO_2.

2.3 Field development

The Skrugard, Havis and Drivis reservoirs are planned as a common investment project with a total of 31 subsea wells. The discoveries are tied-back to a ship-shaped FPSO unit for stabilized oil processing. Further description of the field development concept is given in [1].

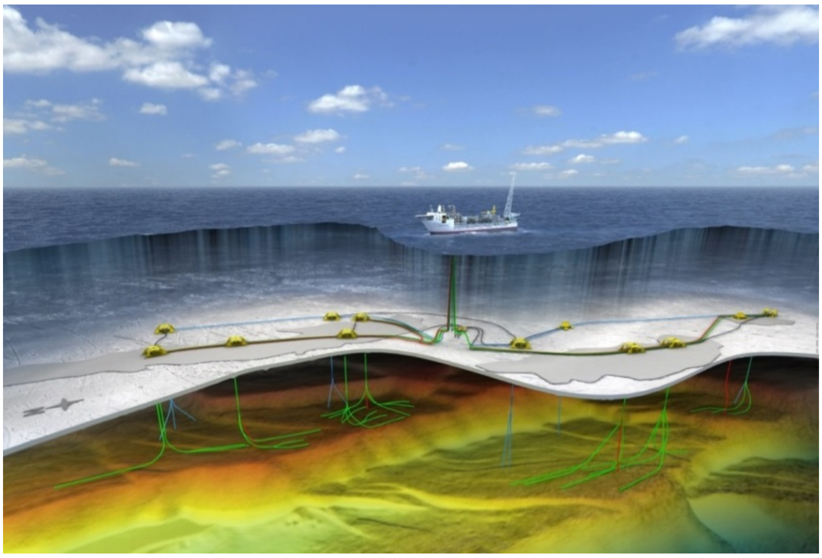

Figure 2-1 Field development concept

The main milestones for the project are given in the table below.

Table 2-1 Main milestones

Main project milestones	Power concept selection	DG2	DG3	PDO approval	DG4
Dates	23rd of June 2016	Nov 2016	Nov 2017	April 2018	Dec 2022

2.4 Power and heat demand

The expected average electrical power demand, injection compressor power demand and heat demand at the FPSO are illustrated in the figures below.

The average calendar day numbers are scaled down from the stream day numbers according to the production availability, and average loads and balanced design margins have been included.

The peak el. demand of approx. 50 MW is the maximum stream day load and includes off-loading, max thruster load and design margins. In operation the actual load will vary over time, most notably due to variations in thruster load, off-loading and water injection rate/pressure. An illustration of the electrical load list for a stream day is given below.

The peak injection compressor power demand of approx. 40 MW is the maximum stream day load and includes design margins.

The peak heat demand of approx. 70 MW is the maximum total stream day load and includes peak winter loads, intermittent loads (e.g. crude oil washing, slop oil heating) and design margins. In operation the actual heat demand will vary over time, most notably due to variations in oil and total liquid production. An illustration of the heat demand for a stream day is given below.

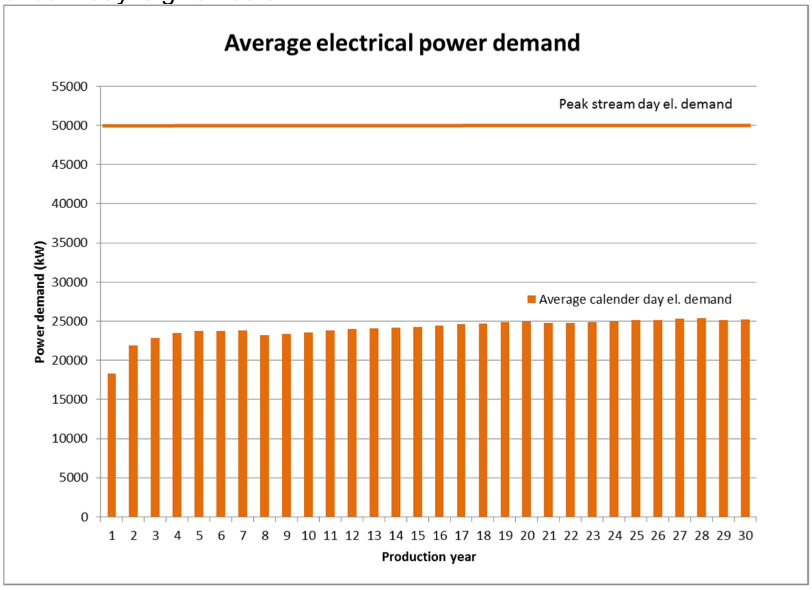

Figure 2-2 Average electrical power demand

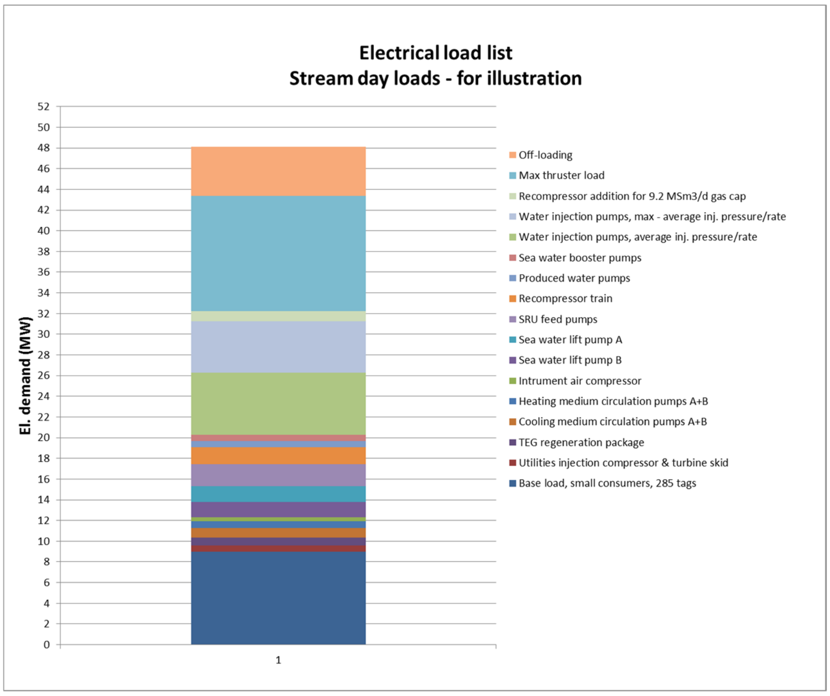

Figure 2-3 Illustration of stream day electrical power loads

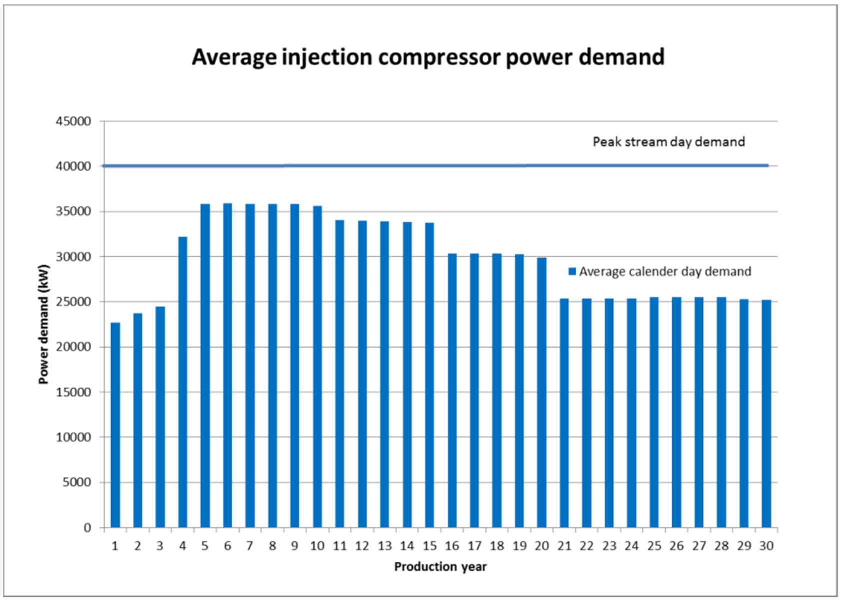

Figure 2-4 Average injection compressor power demand

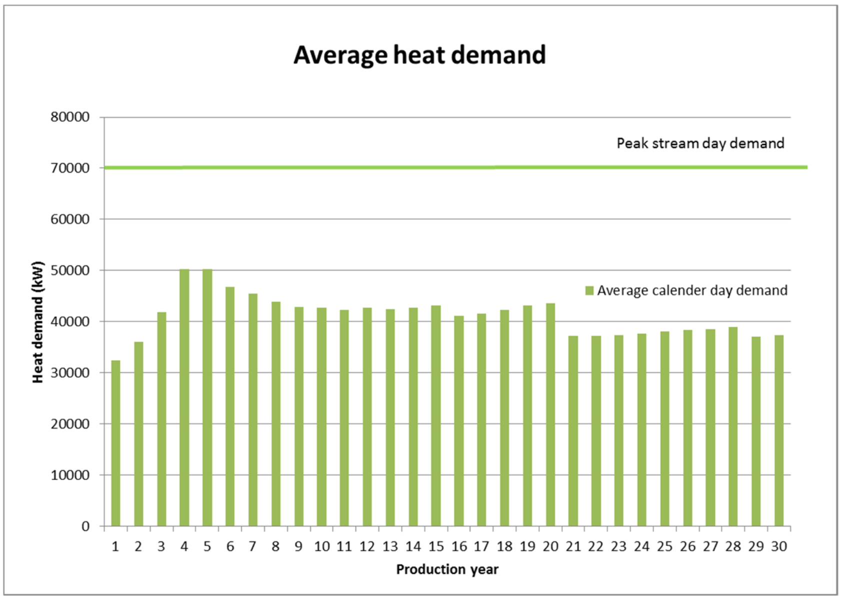

Figure 2-5 Average heat demand

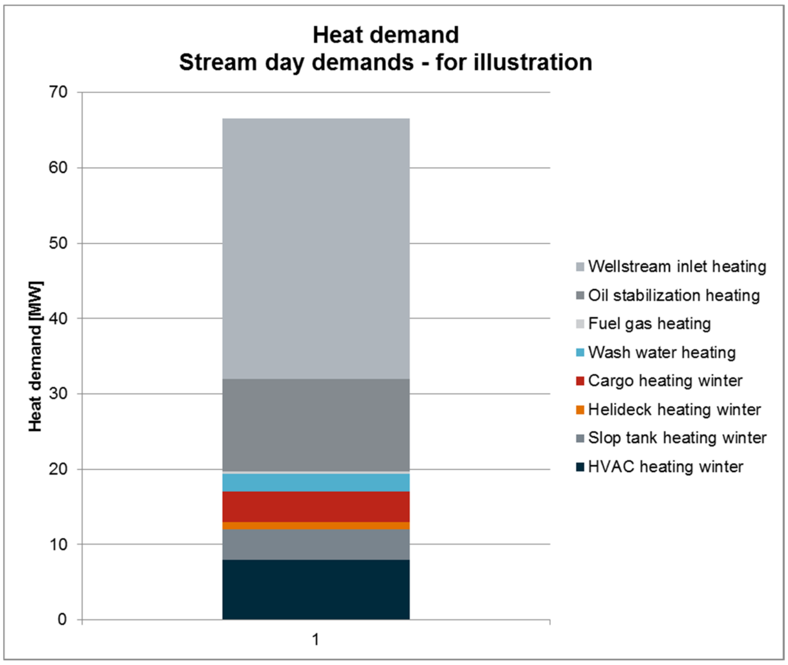

Figure 2-6 Illustration of stream day heat demand

Further details regarding power and heat demand is given in [2].

2.5 Power concept matrix

Power concepts have been identified from available technologies within high voltage direct current (HVDC) and high voltage alternate current (HVAC) and degree of electrification as:

- **Case 0**: Locally produced power and heat. This case is used as base case for comparison
- **Case 1**: Electrification of electrical power consumers
  Base case power generators are exchanged with power from shore. Gas fired heaters needs to be introduced to compensate for loss of process heat from waste heat recovery units. Power demand is set at 70MW to cater for future users (tie-in of new reserves or/and debottlenecking of the FPSO)
- **Case 2**: Electrification of electrical power consumers and gas injection train
  Compared to case 1, gas injection train is also electrified. Additional gas fired heater is needed. Power demand is set at 110MW
- **Case 3**: Electrification of electrical power consumers, gas injection train and heat demand
  Compared to case 2, heaters are electrified. Power demand is set at 160MW

Each concept is further described in Chapter 3 together with related technology qualification program and risks.

Table 2-2 Power concept matrix

			Comments
Locally produced power and heat			
Case 0	a	Offshore gas turbines	Base case
	b	Offshore gas turbines Prepared for future HVAC import for electrification of electrical power consumers	
Electrification of electrical power consumers			
Case 1	a	Power from shore HVDC Separate power host for conversion into HVAC on the field	
	b	Power from shore HVAC 50Hz shunt reactors/ series capacitor	
	c	Power from shore HVAC 50Hz shunt reactors/ STATCOM	
	d	Power from shore HVAC low frequency	
	e	Hywind / Offshore gas turbines HVAC	
Electrification of electrical power consumers and gas injection train			
Case 2		Power from shore HVDC Separate power host for conversion into HVAC on the field	
Electrification of electrical power consumers, gas injection train and heat demand			
Case 3		Power from shore HVDC Separate power host for conversion into HVAC on the field	

Other power concepts and/or electrification alternatives that has been identified but not pursued for different reasons are given in Table 2-3.

Table 2-3 Power concepts and/or electrification alternatives not pursued

Concept	Reason
HVDC direct to FPSO (without power host)	Qualification of a HVDC swivel is considered to take more than 3 years
FPSO prepared for future HVAC import for electrification of electrical power consumers and GI compressor	Requires considerable redesign and following schedule impact
Electrification of electrical power consumers and heat demand	High power demand from shore; between cases 2 and 3. Inefficient; The energy efficiency of gas fired heaters is higher than for power from shore considering the transmission losses to the national grid in Finnmark.
A combination of power from shore by HVAC and one local GTG, to provide power from shore to stable consumption and apply GTG as swing machine	Increase cost and less CO_2 removed, i.e. higher abatement cost than Case 1b. The voltage instability challenges remains
HVAC with higher degree of electrification	Brief evaluations performed by Unitech on electrification of electrical power consumers and gas injection train (110 MW); concluding that such system is not feasible using one cable. Feasibility could be achieved using two cables at approximately double cost.

2.5.1 CO_2 emissions

The yearly average CO_2 emissions at the FPSO for the power concepts are illustrated in the figure below.

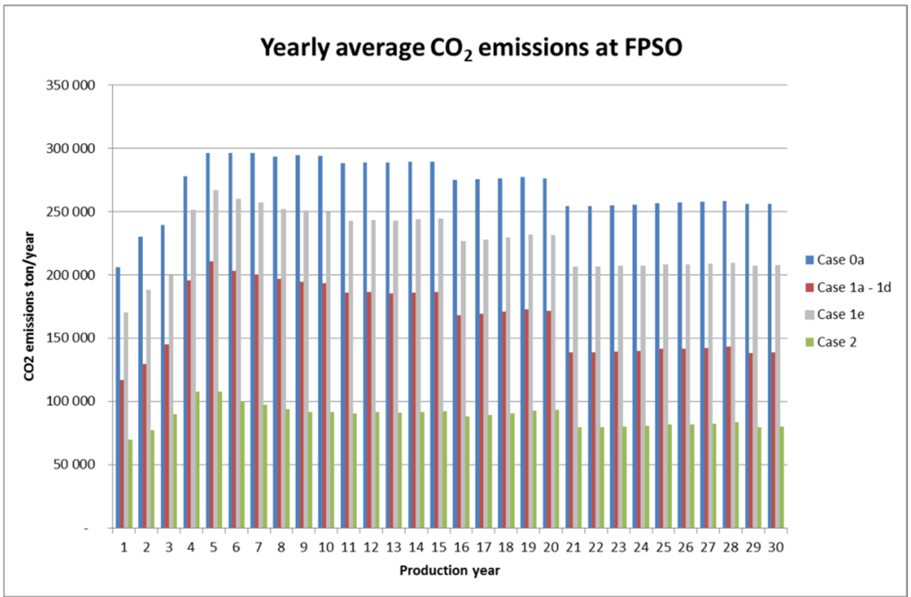

Figure 2-7 Yearly average CO_2 emissions

The table below presents the energy efficiencies and CO_2 intensities for all evaluated concepts.

Table 2-4 Energy efficiencies and CO_2 intensities

Average over the lifetime	Energy efficiency (%)	CO_2 intensity (gCO_2/kWh)	CO_2 intensity (kg CO_2/boe)
Case 0a	64	325	14.1
Case 1a-1c	79	198	8.6
Case 1d	73	198	8.6
Case 1e	77	271	11.8
Case 2	82	106	4.6
Case 3	80	NA	NA

Compared with other producing NCS field Case 0a has high energy efficiency, this due to the utilization of the waste heat from the turbines. A benchmark with producing assets on Haltenbanken is shown in Table 2-5.

Table 2-5 CO_2 emissions, energy efficiencies and CO_2 intensities – producing assets

Field	Yearly emission (ton CO_2/year)	Energy efficiency (%)	Energy efficiency (g CO_2/kWh)	CO_2-intensity year 2015 (kg CO_2/boe)
Kristin	310 000	52	440	8
Heidrun	370 000	46	400	18
Norne	370 000	46	400	24

The energy efficiency numbers for the electrification cases 1a – 1d, 2 and 3 only take into account the el. transmission losses from Hyggevann to the FPSO (estimated to 38% for case 1d, 20% for the other cases). The CO_2 intensity numbers for the electrification cases 1a – 1d, 2 and 3 are based on el. power delivered at Hyggevann with a CO_2 intensity of 0 gCO_2/kWh.

Sensitivities on CO_2 emissions and the effect on energy efficiency numbers are presented in App A.
A detailed overview of the losses in the overall power system is given in App B.

In case 1e, the Hywind case, minimum one of the LM2500+G4 turbines is assumed running at all times down to a minimum load of approx. 11%. In average 40% of the el. power demand is covered by the wind turbines based on analysis of availability of power i.e. wind statistics/power availability over the year, and el. power demand over the year. A fourth wind turbine would increase the wind coverage somewhat but with increased abatement cost due to the higher CAPEX.

Further details regarding CO_2 emissions, energy efficiencies and CO_2 emissions are given in [2].

2.6 Framework

2.6.1 Petroleum Technology

Drainage strategy:
The electrification cases will require less fuel-gas, i.e. there will be extra gas for re-injection into the reservoir. The volume of extra gas injected will be in the range of 50-300 kSm3/d which result in a total of 0.6- 3.5 GSm3 extra gas injected during the field life time dependent of the selected electrification case.

Due to the extra gas injection, the gas cap will expand with 2-10 meters depending on the electrification case. The optimal location of the producers will be somewhat deeper than planned for in the current base case. It is considered a reasonable assumption that the wells can be optimised in order to maintain the production profile and recoverable reserves. If electrification is selected, the well placement for the oil producers have to be updated and the impact on DW time- and cost estimates adjusted. As the changes are expected to be minor, and not significantly influence the economy or the Design Basis, the potential update will be handled as part of the work towards DG3.

Production profiles for electrification cases:
The production profiles used for input to the power from shore evaluations are based on the concept selection profiles from December 2015. The concept selection profiles for economy are corrected with a negative delta production volume of 0.5 MSm3 corresponding to the net volume effect caused by the changes for Skrugard North and Drivis approved by MC 28.02.2016.

For each case the production profiles are corrected with the expected regularity described in Chapter 4.
Delta oil- and gas profiles are given in [3].

2.6.2 Drilling and well

The drilling and well solutions are, based on the assumptions described in section 2.6.1, in these evaluations assumed to be identical for all evaluated power concepts. For description of well solutions reference is given to [1].

Table 2-6 Well overview

	Producers			Water Injectors			Gas Injectors			Total Wells
	Wells	Reservoir targets	MLT wells	Wells	Reservoir targets	MLT wells	Wells	Reservoir targets	MLT wells	
Skrugard	10	15	5	5	5	0	2	2	0	17
Havis	6	7	1	3	3	0	1	1	0	10
Drivis	2	3	1	1	1	0	1	1	0	4
Total	**18**	25	7	**9**	9	0	**4**	4	0	**31**

2.6.3 Floater

The main design capacities and parameters shown in Table 2-7, are basis for all evaluated power concepts.

Table 2-7 Main design capacities and parameters

Description	Unit	
Design oil production rate	Sm^3/sd	30 000 (190 000bbl/d)
Design water production rate	Sm^3/sd	34 000
Design liquid production rate	Sm^3/sd	40 000
Design gas production rate, incl. gas lift	MSm^3/sd	9.2
Riser slots (total/spare)	No.	21/10
LQ capacity (cabins/beds)	No.	120/140 20 turnable beds
Offshore oil storage capacity	Mbbl	1.1

Base case FPSO (Case 0) are equipped with 3 turbines, two for power generation (LM2500+G4) and one for gas injection (LM6000), waste heat recovery units installed on all three to provide required process heat.

2.6.4 Subsea

The subsea layout shown in Figure 2-8 is identical for all evaluated power concepts. Any changes to well locations are expected to be minor; hence any update to template/satellite locations will be handled as part of the work towards DG3

Any dynamic power cables routed to the FPSO will be located in the south sector for all evaluated power concepts, except for cases 2 and 3 where more than 3 off power cables may be required; hence they will have to be routed under the FPSO into north-west sector. A possible power host will be located south-east of the FPSO as shown in Figure 2-9, approximately 3km from the floater. Power cables from shore to the power host or FPSO will be rock dumped and/or trenched.

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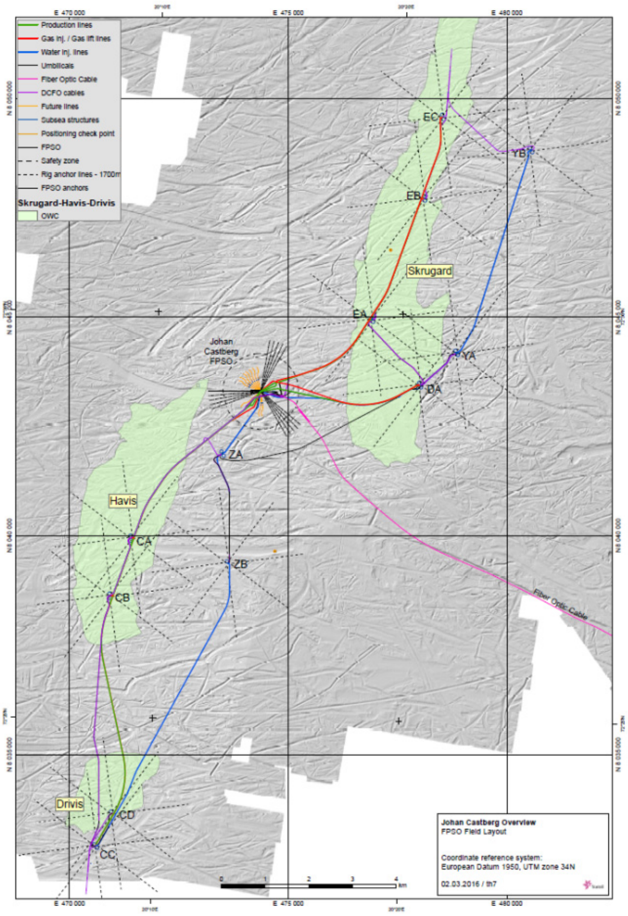


Figure 2-8 Field layout

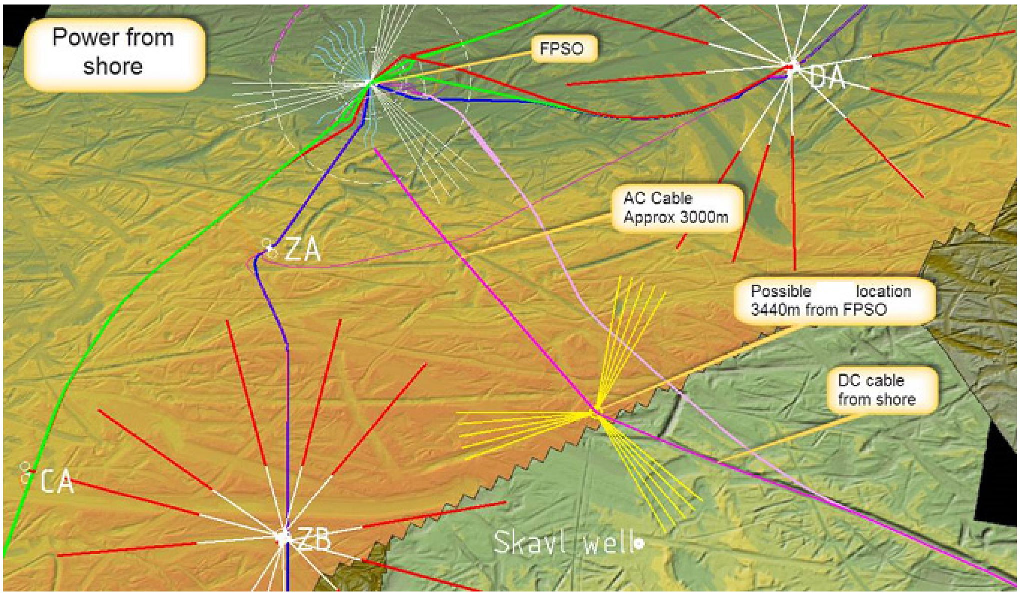


Figure 2-9 Power host location

2.6.5 Onshore Power grid

General grid strengthening:
Independent of JC, National main grid owner (Statnett) is currently strengthening the grid in northern Norway with 420 kV lines. See Figure 2-10 below.

First step; Ofoten – Balsfjord is strengthened with one additional 420 kV line, due date 2017
Second step; Balsford - Skaidi is strengthened with a new 420 kV line, due date 2020
Third step; Alta – Skaidi, will be operated at 132 kV, allowing Statnett to postpone new transformer station 420/132 kV in Skaidi until additional power requirements are requested. Case 3 will trig the need for upgrading operational voltage to 420 kV to Skaidi and even further to Hammerfest

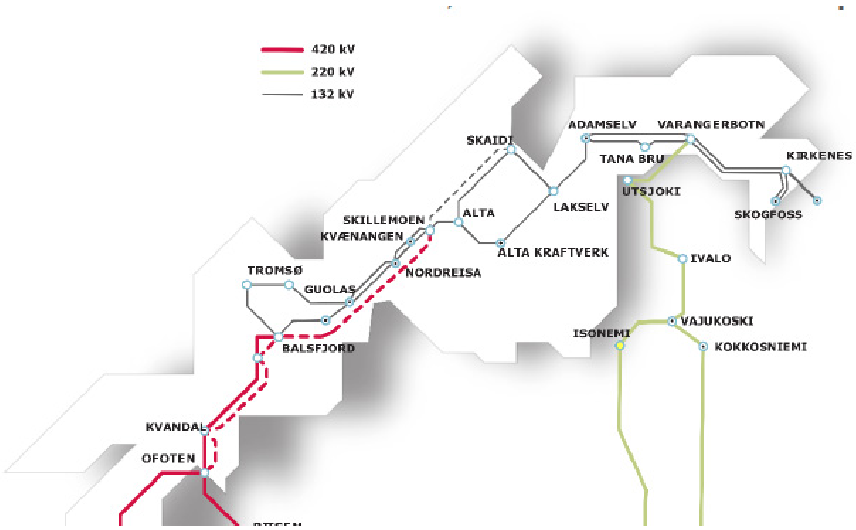


Figure 2-10 General grid strengthening

Local grid strengthening trigged by JC, case 1 & 2:
The onshore grid connection point for JC is, for all cases, the 132 kV power station at Hyggevann, close to Hammerfest town.

For case 1 and 2 the grid need to be strengthened by a third 132 kV line Skaidi – Hyggevann. Hyggevann station has to be extended with 3 new breaker fields, see red lines in figure below. This is reflected in CAPEX calculations.

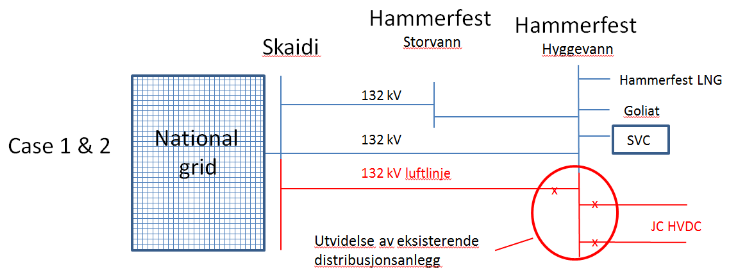


Figure 2-11 Local grid strengthening, Case 1 and 2

Local grid strengthening trigged by JC, case 3:
For case 3 a 420 kV grid has to be prolonged from Skaidi to Hyggevann, where a new 420 kV transformer station has to be erected.
Based on signals from grid owner, Statoil has to carry the expenses for grid strengthening Skaidi - Hyggevann, and part of new power station at Hyggevann. This is reflected in CAPEX calculations.

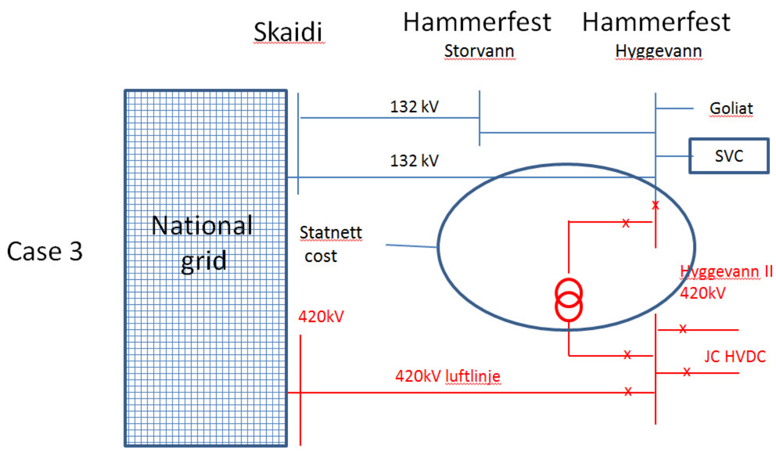


Figure 2-12 Local grid strengthening, Case 3

Grid stability
The onshore HVDC converter behaves like fast acting voltage compensators for stabilizing the voltage at the connection point (Hyggevann), same principle as the STATCOM units applied for ENI/ Goliat. Hence, no onshore grid instability issues are foreseen caused by dynamic load changes at Johan Castberg.

Grid reliability
Reference is made to 53.

Statnett Study for Snøhvit, 2012, calculates how often and for how long the grid will reach a situation where load shedding is needed in order to save the grid from collapse. This number includes maintenance outages and expected faults that make the grid weaker. The numbers are:

- Expected number of outages and load shedding pr. year: 0.72 events/year
- Expected time with outages and load shedding: 3.22 hours/year

Maintenance outage can, in some degree, be planned coordinated with Johan Castberg revision stops.

A grid outage, independent of how short durance, will cause 5 hours full production loss in average.

Furthermore short time grid voltage dips (typically 50 – 100 ms fault clearing times), caused by wind (phase-to-phase connection) and snow/ ice (earth fault), may cause trip of HVDC-converter. The number is estimated to be ca. 0.1 trips pr. Year, following a 5 hour full production loss.

The total production outage caused by onshore grid faults is calculated to 7, 32 hrs/ year, corresponding to an availability of 99, 92%.

For comparison, the overall availability of power transfer system (including onshore grid, HVDC converter, HVDC cabling, power host, AC-cabling, and transformers) is calculated to 98, 32%.

3 Power concepts – technical description

Each power concept has in chapters below been described on a generic form containing:

- **3.x.1** Concept description
- **3.x.2** Technology Qualification Program
- **3.x.3** Additional risks compared to base case

3.1 Offshore gas turbines - Case 0a

3.1.1 Concept description

The base case power solution is based on local power and heat generation using gas turbines with waste heat recovery units (WHRU), resulting in an average energy efficiency of 64%. For further description of the base case FPSO, reference is made to the concept selection report given in Section 8.
The layout of the FPSO is shown below, with gas turbine generators located on poop deck, aft port side. The layout has been optimized to provide space and weight for future modules.

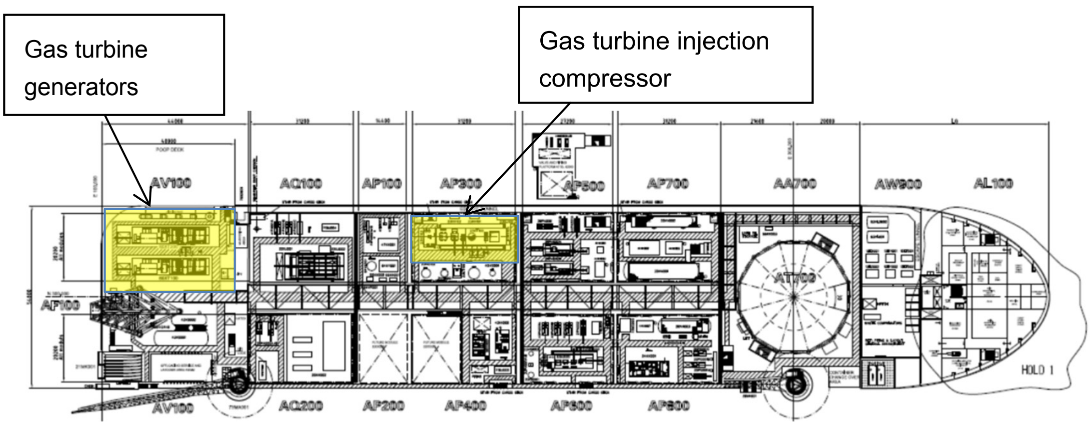


Figure 3-1 FPSO layout

3.1.2 Technology Qualification Program

No technology qualifications are necessary for the electrical systems in the base case.

3.1.3 Additional risks compared to base case.

NA.

3.2 Offshore gas turbines - Case 0b: Prepared for future HVAC import

3.2.1 Concept description

Case 0b) has the same power solution as the base case, but space and weight has been provided to allow for future import of HVAC. This includes space and weight for gas boilers, transformers, and a future electrical swivel (45 kV). As a consequence, the metering package needs to be moved to the process area, and the swivel stack will increase in height. Less space and weight will be available in the process area for installation of future modules.
Extending the utilization of the Hull area to avoid reduction in future areas is not considered realistic, as it will require major redesign due to availability of areas and interface challenges.

The FPSO layout for case 0b) is shown below:

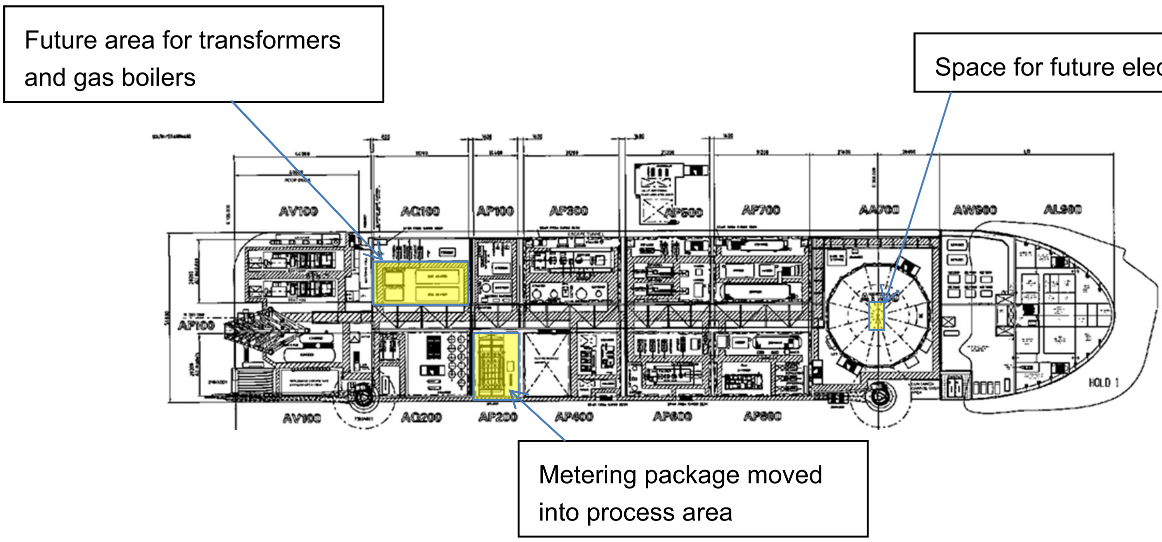


Figure 3-2 FPSO layout

3.2.2 Technology Qualification Program

No technology qualifications are necessary for the electrical systems in case 0b)

3.2.3 Additional risks compared to base case.

The execution risk for this alternative will be slightly higher than the base case, since the layout and swivel stack of the FPSO will need to be modified.

3.3 Power from shore – Case 1a: Power from shore HVDC

3.3.1 Concept description

Case 1a) is based on power from shore via a power host platform. AC power is converted to DC power at an onshore HVDC plant. HVDC Power is then transferred to an offshore power host platform, where HVDC is converted to HVAC. HVAC is transferred to the FPSO, through 2x50 % transformers/ cables. The choice 2x50 % gives redundancy with respect to production and avoids the need for spare transformers. It also solves the problem with overheating of dynamic AC cable trough the bend stiffener. The cables are entering the turret and continued to the FPSO through a 33kV swivel. On the FPSO, the power is transformed to 11kV. The average power loss in the system is expected to be 20%.

Main generators with waste heat recovery units are not installed. Gas boilers 2x25 MW are installed to replace the waste heat recovery units required for process heat. The essential generator is split into 2x50 % generators on the FPSO to ensure two sources of black-start power to the power host platform.
The sea cabling (DC cables, AC cables and FO cables) are shown in the figure below.

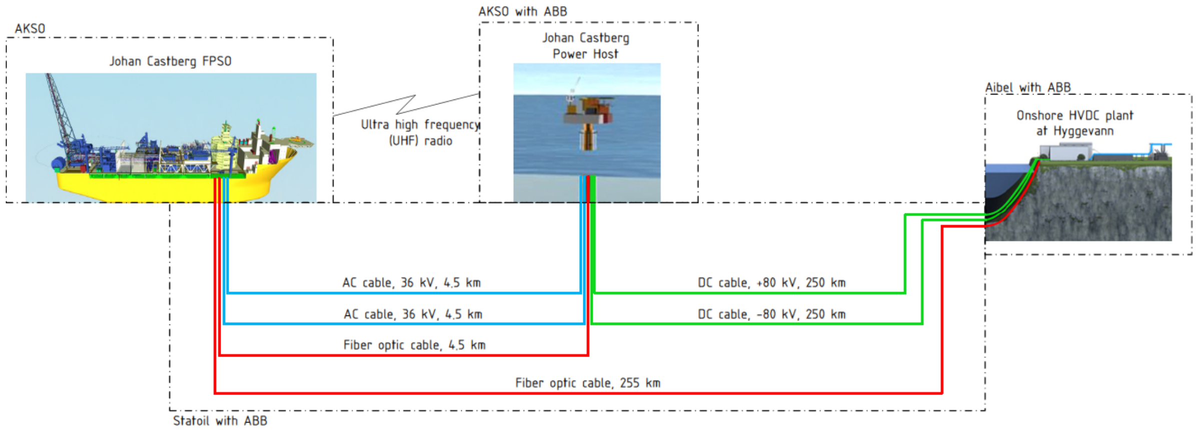


Figure 3-3 Power concept

The electrical single line diagram for the main power string is shown below.

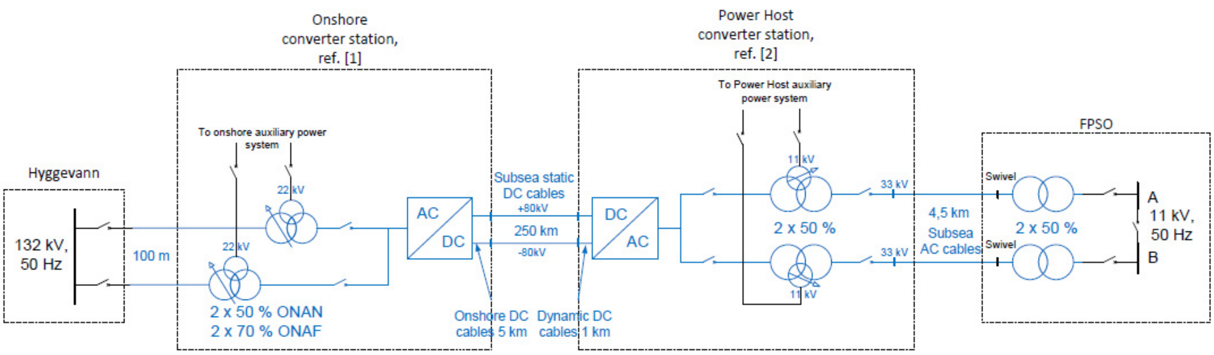


Figure 3-4 Electrical single line diagram

Block diagram for offshore part of the power supply and consumption is shown below.

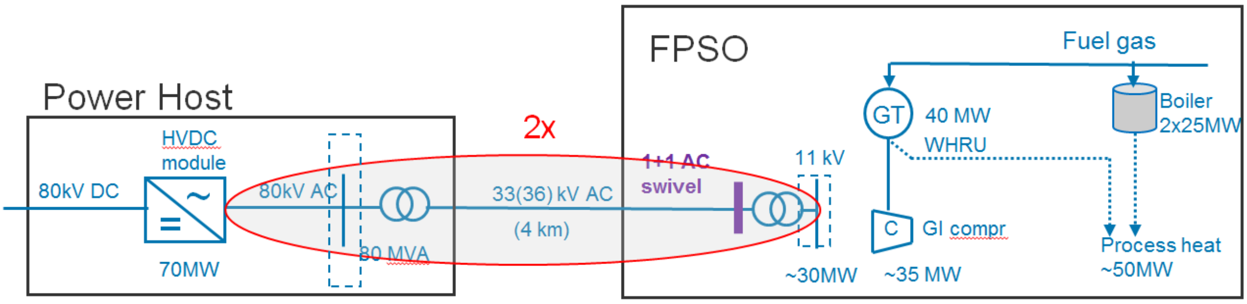


Figure 3-5 Offshore block diagram and consumption

The FPSO layout for case 1a) is shown below. The layout has the same flexibility for installation of future modules as the base case.

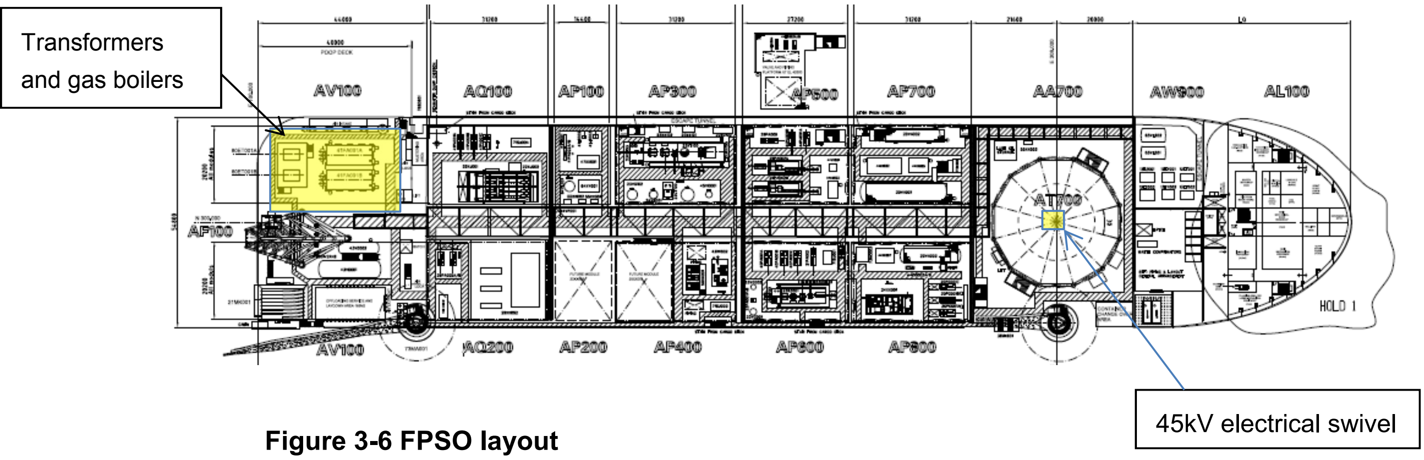


Figure 3-6 FPSO layout

3.3.2 Technology Qualification Program

The technology qualifications required for this alternative will be:

- Installation of a HVDC plant on a floating platform, anticipated 1 year, medium risk
- Qualification of dynamic DC cables, including probable offshore joint, anticipated 2 years, high risk

3.3.3 Additional risks compared to base case.

The execution risk for case 1a) is higher than for the base case, since the power host is only matured to a class B level, and that there are technology qualifications that needs to be resolved.

3.4 Power from shore – Case 1b: HVAC 50Hz shunt reactors/ series capacitor

3.4.1 Concept description

Power from shore by HVAC (50 Hz) is realized by:

- Shunt reactors in both cable ends to mitigate cable capacitance
- Onshore series capacitor to mitigate serial impedance caused by large inductance in onshore power grid and sea cable
- STATCOM to control reactive power exchange with onshore grid, and for counteracting voltage fluctuations offshore upon load changes
- Subsea autotransformer for voltage adaption to proven swivel technology level 45 (52) kV

Transfer voltage is 110 kV AC. 2x50 % solution is applied for transformers and dynamic cabling, as for case 1a HVDC. Swivel voltage is increased from 33 kV to 45 kV to provide 70 MW power supply on board the FPSO. The FPSO impact will be as for case 1a) HVDC, i.e. two transformers two 25 MW gas fired boilers and a HV swivel. Reference is made to single line diagram below.

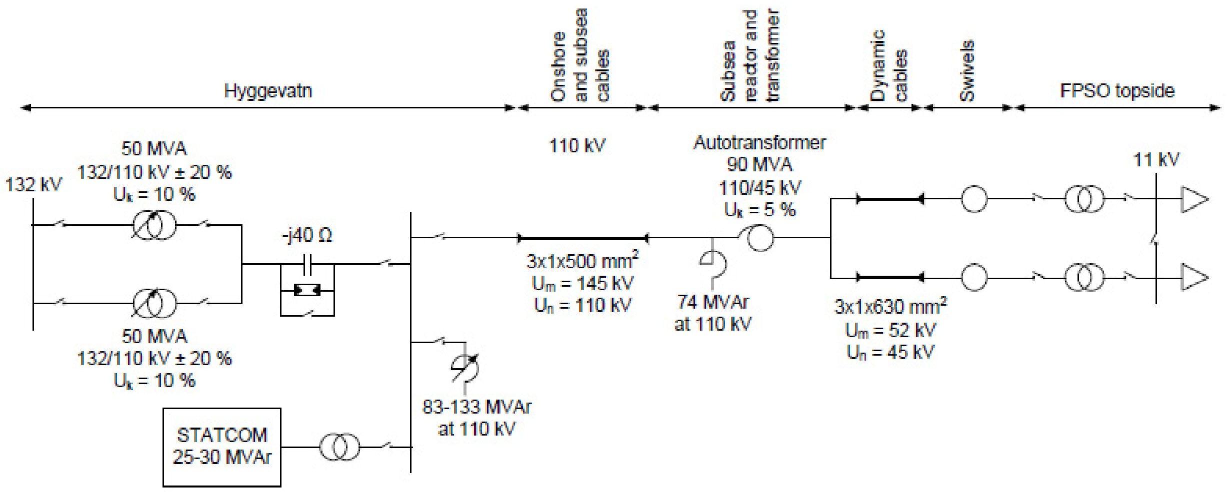


Figure 3-7 Electrical single line diagram

Onshore transformers, reactor and capacitor may be installed outdoor in open shelter (carport). STATCOM has to be installed in-house. The average power loss in the system is expected to be 20%.

3.4.2 Technology Qualification Program

System solution: Never realized, but technical feasible according to recent studies made by Unitech and ABB. No show stopper have been observed However, the system solution requires a thorough verification program with detailed calculations (6 – 12 months), to confirm technical solution with sufficient low risk for system selection.

Subsea transformer and reactor (common skid): Qualification done for smaller sizes, 19 MVA for Åsgard Subsea and 20 (70) MVA for Ormen Lange. (70 MVA proven as desktop study but only 20 MVA realized). Assumed to be low risk, but complex installation, heavy weight (600 tons), and pre-terminated HV cables attached during installation. A heavy lift vessel is required. Solution relies on on-going qualification of 45 (52) kV wet mate connectors, due date 2017, assumed to be low risk with respect to TRL4 within Date for DG3.

Dynamic AC cable: Qualified with higher voltage at Gjøa and Goliat. Johan Castberg requires a different cable (less isolation, larger cross section), but the challenge (watertight barrier) is equal. Assumed low risk TQP, but one year endurance/fatigue test required.

Dynamic AC cable penetrating bend stiffener: TQP not required, but a dynamic endurance test is necessary, which has to be done for any new combination of cable and bend stiffener is required. Verification required, estimated time 1.5 years.

Offshore splice of HVAC 145 kV cable: The HVAC cable cores pre-terminated to the subsea transformer and reactor will need to be jointed offshore to the HVAC power cable from shore, since this cannot be installed in one operation. Statoil have experience with offshore jointing at this voltage level, but not necessarily with this specific cable type. Testing may be required, but low risk regarding result and time frame.

3.4.3 Additional risks compared to base case.

Subsea cable and auto transformer is non-redundant, but have long mean time before failure (MTBF).
Series capacitor can be by-passed, but system will be exposed to voltage instability during by-pass period, upon load changes. A redundant capacitor may be installed. Most likely the system will manage without STATCOM, and grid owner will accept a repair time without reactive compensation. System will manage without onshore reactor as well, maybe with somewhat limited transfer capacity. Overall, a high reliability is expected.

The execution risk is higher than for the base case, since the power supply design is only matured to a feasibility level, and that there are technology qualifications that needs to be resolved.

3.5 Power from shore – Case 1c: HVAC 50Hz shunt reactors/ STATCOM

This case is considered non-feasible due to high probability of voltage instability and hence this alternative is not further described in the report.

3.6 Power from shore – Case 1d: HVAC low frequency

3.6.1 *Concept description including:*

Low frequency AC (LFAC) is based on onshore conversion of frequency from 50 Hz to 16,7 Hz (1/3 of 50 Hz) for power transfer, and conversion back to 50 Hz on FPSO.

To change frequency the 50 Hz system need to be rectified to DC before inverting to LFAC system. Hence, it is required two VSC (HVDC) converters back-to-back both onshore and offshore. Reference is made to single line diagram below.

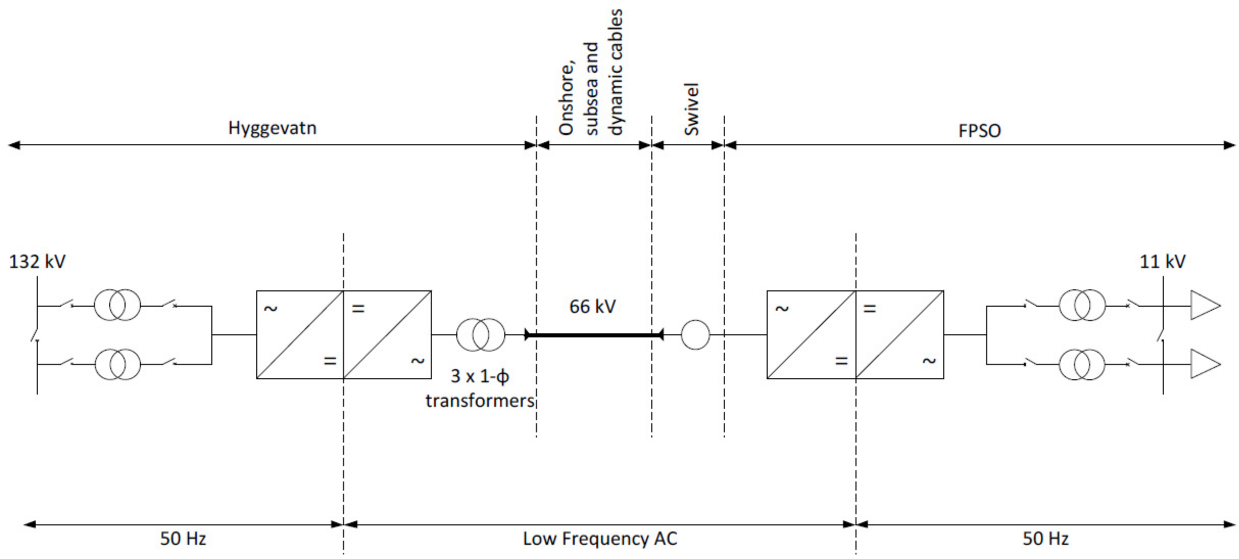


Figure 3-8 Electrical single line diagram

Voltage adaption is done by 2x50 % transformers in both ends, as for case 1a.

Subsea autotransformer is not required, based on the possibility for reduced transfer voltage (66 kV) and allowing for qualification of HV swivel. The onshore transformer is, because of low frequency, very heavy. By reducing frequency to 1/3, iron core cross section has to be increased accordingly, and the total weight is three times a 50 Hz transformer, approximately 450 tonnes. Hence, it is proposed to split the transformer in three one-phase transformers.

The solution is very expensive component wise, space consuming, and causes large power losses. The average power loss in the system is expected to be 38%. Converter module size on FPSO will be approximately 30x32x14 m (WxLxH), and will require considerable re-arrangement on aft Topside.

This case is not cost estimated as considered not to give any improved abatement cost or schedule impact results.

3.6.2 *Technology Qualification Program*

System solution: Never realized, but technical feasible according to provisional calculations by Unitech (low risk).

HV LFAC swivel): At maximum load reduction a short time overvoltage up to 81 kV may occur. Even though voltage normally is controlled down to 66 kV again, this cannot be guaranteed. Hence swivel TQP is required for 110 (123) kV, anticipated 1,5 years duration, with high risk.

VSC converter (back-to-back HVDC converter) installed on FPSO: A VSC converter on a floater is never realised. For case 1a) it is considered medium risk with installation on a SPAR-type floater with moderate movements (heel and accelerations). Installing a VSC converter on a FPSO will become high risk, because worst case heel and roll and accelerations are larger.

Dynamic AC cable: Qualified at Gjøa and Goliat. Johan Castbeg requires a different cable (larger cross section), but the challenge (watertight barrier) is equal. Assumed low risk TQP, but one year endurance/fatigue test required.

Dynamic AC cable penetrating bend stiffener: TQP not required, but a dynamic endurance test is necessary, which has to be done for any new combination of cable and bend stiffener is required. Verification required, estimated time 1.5 years.

3.6.3 Additional risks compared to base case.

Many non-redundant components in series, assumed to reduce regularity.
Considerable space will be required for the converter on board the FPSO, requiring extensive re-design and possible extension of the hull size.

The execution risk is considerably higher than for base case. The power supply design is immature (feasibility level), and there are high risk technology qualifications required.

3.7 Power from shore – Case 1e: Hywind & Gas turbines

3.7.1 Concept description

The system is based on case 0b) FPSO with 2 x GTG, prepared for alternative electricity supply from a Hywind park, rated 3x8 MW, installed 10 km east of the FPSO.

Hywind installation is an add-on system to base case solution, enabling closedown of one GTG and reducing load on second GTG during stable wind power conditions. One GTG is still needed in operation providing spinning reserve and to cope with instant load changes.

With respect to dynamic response time a wind turbine is rather slow. Therefore Hywind installation is equipped with a battery with capacity of 8 MWh, to counteract short time power fluctuations, also enabling the GTG to operate at a more stable load. Reference is made to block diagram below.

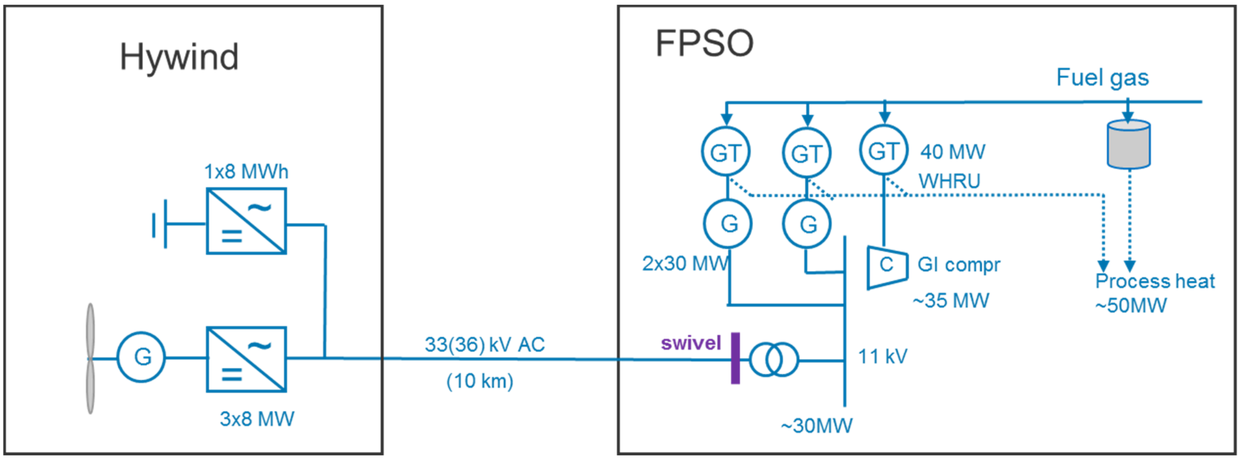


Figure 3-9 Block diagram and consumption

The Hywind Structure is a spar foundation anchored in three mooring lines with suction anchors. Dynamic AC cables are used to transfer power between the individual floating wind turbines and FPSO.

The Hywind park will be accessed using a gangway on the JC supply vessel. O&M is assumed with assistance from JC technicians and support from WTG Manufacturer when required. There is one planned maintenance campaign per year and it is estimated one day per WTG

Installation of 2x25 MW gas fired boilers will be required, as for case 1a.

3.7.2 Technology Qualification Program

System solution: Wind power generation supplying a dynamic power system, where power generation and consumption have to match at all time, to avoid frequency fluctuations, is a challenge. Different response times for unequal power sources will constitute a control challenge, and Power Management System will be complex. This is never realised, and is regarded a medium risk with respect to project execution time for detail design and commissioning.

WTG rating: Proven technology up to 2,3 MW (Karmøy, 2009), TRL3 for 6 MW (planned pilot park, Scotland), JC planned for 8 MW. Stretching limits, assumed medium risk.

Battery: Small scale applications realized for DP ships for peak shaving. Hywind Valemon & Kvitebjørn project due summer 2017.

3.7.3 Additional risks compared to base case.

PE for power system is expected to be high. Power generation are more or less a 3x50 %.
The project execution risk is higher than for base case, based on TQP requirements. The power supply design is immature (feasibility level), and commissioning is expected to be a challenge.

3.8 Power from shore – Case 2: HVDC Electrification of electrical power consumers and gas injection train

3.8.1 Concept description

Power from shore is provided for supplying both base case electrical consumption and gas injection compressors. I.e. LM6000 gas turbine drive for compressors is replaced by three electrical drives. All WHRUs are replaced by gas fired boilers.

The HVDC transfer system is equal with case 1a, except ratings, which is increased from 70 to 110 MW. HVDC voltage is still +/- 80 kV, as in case 1a.

A dedicated power host is required.

Onshore grid strengthening is required as in case 1a.

HVDC converter stations size/ weight are mostly voltage driven. Hence weight is only slightly increased (10%) compared to case 1a. But no. of HVAC transformer/ cable strings is increased from 2 to 4, and an 80 kV GIS switchboard has to be installed on Power Host, driving size/ weight.

FPSO impact is considerable:

- 3x25 MW gas fired boilers are required on topside for process heat
- 2x40 MVA transformers for voltage reduction to 11 kV are required, as in case 1a
- Complete GI module re-design to facilitate electric drives
- Two additional 40 MVA transformers are required on top side feeding GI drives
- Aft utility area electrical rooms require large expansion with considerable layout impact, to provide for three new electrical GI compressor drives (HV switchboard, 2 transformers and/ VSDs)

Reference is made to block diagram below.

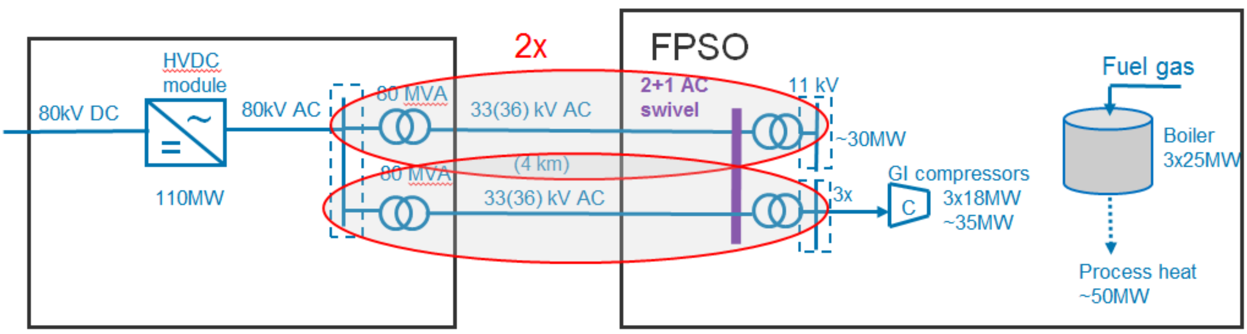


Figure 3-10 Offshore block diagram and consumption

3.8.2 Technology Qualification Program

The technology qualifications required is same as for case 1a:

- Installation of HVDC plant on a floating platform, anticipated 1 year, medium risk
- Qualification of dynamic DC cables, including probable offshore joint, anticipated 2 years, high riskAdditional risks compared to base case.

The execution risk is considerable higher than for base case. The extensive FPSO changes are not assessed, even at feasibility level. The power host growth is neither assessed. Furthermore, technology qualifications with extensive risk are required.

3.9 Power from shore – Case 3: HVDC Electrification of electrical power consumers, gas injection train and heat demand

3.9.1 Concept description

Power from shore is provided for supplying base case electrical consumption, gas injection compressors and process heat boilers. I.e. LM6000 gas tubine drive for compressor string is replaced by three electrical drives. All WHRUs are replaced by el-powered boilers.

The HVDC transfer system is equal with case 1a, except ratings, which is increased from 70 to 160 MW. HVDC voltage is still +/- 80 kV, as in case 1a.

A dedicated power host is required.

Onshore grid strengthening is required as in case 1a.

HVDC converter stations size/ weight are mostly voltage driven. Hence weight is only increased with 20% compared to case 1a. But no. of HVAC transformer/ cable strings is increased from 2 to 6, and an 80 kV GIS switchboard has to be installed on Power Host, driving size/ weight.

FPSO impact is considerable:

- 3x25 MW el-boilers are required on topside for process heat
- 2x40 MVA transformers for voltage reduction to 11 kV are required, as in case 1a
- Complete GI module re-design to facilitate electric drives
- 4 additional 40 MVA transformers are required on top side feeding GI drives and boilers
- Aft utility area electrical rooms require large expansion with considerable layout impact, to provide for three new electrical GI compressor drives and boilers(2 HV switchboards, 3 transformers/ VSDs)

Reference is made to block diagram below.

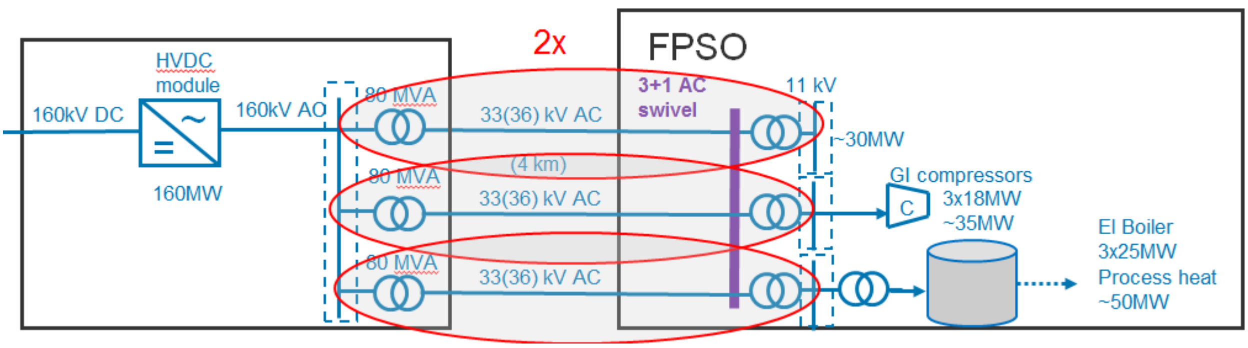


Figure 3-11 Offshore block diagram and consumption

3.9.2 Technology Qualification Program

The technology qualifications required are same as for case 1a:

- Installation of HVDC plant on a floating platform, 1 year, medium risk
- Qualification of dynamic DC cables, including probable offshore joint, anticipated 2 years, high risk

3.9.3 Additional risks compared to base case.

The execution risk is considerable higher than for base case. The extensive FPSO changes are not assessed, even at feasibility level. The power host growth is neither assessed. Furthermore, technology qualifications with extensive risk are required.

4 Production efficiency

The PE-estimate for the base case (Case 0a) is unchanged since concept selection.

Table 4-1 Production efficiency – Case 0a

FPSO	PE Loss group 2	PE Loss group 3		PE Loss group 4	PE Loss group 5	PE loss group 6		Gefac
Year	SPS benchmarked [%]	topside process modelled [%]	topside - benchmark [%]	Turnarounds [%]	Offloading [%]	Others [%]	Start-up [%]	Mean [%]
Q4 2022	1,4	3,7	1,5	0,0	0,2	0,4	10,0	82,8
2023 Q1-Q2	1,4	3,7	1,5	0,0	0,2	0,4	7,0	85,8
2023 Q3-Q4	1,4	3,7	1,5	0,0	0,2	0,4	1,5	91,3
2024	1,4	3,9	1,5	0,0	0,2	0,4	0,0	92,6
2025	1,9	4,5	1,5	4,6	0,2	0,4	0,0	86,8
2026	2,7	3,9	1,5	0,0	0,2	0,4	0,0	91,3
2027	2,9	3,6	1,5	0,0	0,1	0,4	0,0	91,4
2028	2,9	4,6	1,5	0,0	0,1	0,4	0,0	90,5
2029	2,9	3,9	1,5	4,6	0,1	0,4	0,0	86,5
2030	2,9	4,5	1,5	0,0	0,1	0,4	0,0	90,5
2031-2039	3,0	4,1	1,5	0,0	0,1	0,4	0,0	90,9
2031-2039*	3,0	4,1	1,5	4,6	0,1	0,4	0,0	86,3
2040-2050	3,0	4,2	1,5	0,0	0,1	0,4	0,0	90,8
2040-2050*	3,0	4,2	1,5	4,6	0,1	0,4	0,0	86,2
Comments		Based on simulation model of topside process	Based on Statoil PE experience from other fields on NCS		Only unavailability of offshore loading caused by weather problems or delayed shuttle tanker is concidered.	Authority-imposed reductions, Strike/lock-out, Weather problems, Safety/emergency preparedness requirement, Others		

For the alternative power concepts an additional PE loss group is added related to the power systems as shown for Case 1a, in the below table 4.2.

Table 4-2 Production efficiency – Case 1a

FPSO	PE Loss group 2	PE Loss group 3		PE Loss group 4	PE Loss group 5	PE loss group 6			Gefac
Year	SPS bench-marked [%]	topside process modelled [%]	topside - benchmark [%]	Turnarounds [%]	Offloading [%]	Power host [%]	Others [%]	Start-up [%]	Mean [%]
Q4 2022	1,4	3,5	1,5	0,0	0,2	1,2	0,4	10,0	81,8
2023 Q1-Q2	1,4	3,5	1,5	0,0	0,2	1,2	0,4	7,0	84,8
2023 Q3-Q4	1,4	3,5	1,5	0,0	0,2	1,2	0,4	1,5	90,3
2024	1,4	3,8	1,5	0,0	0,2	1,2	0,4	0,0	91,6
2025	1,9	4,4	1,5	4,6	0,2	1,2	0,4	0,0	85,8
2026	2,7	3,7	1,5	0,0	0,2	1,2	0,4	0,0	90,3
2027	2,9	3,5	1,5	0,0	0,1	1,2	0,4	0,0	90,4
2028	2,9	4,4	1,5	0,0	0,1	1,2	0,4	0,0	89,5
2029	2,9	3,8	1,5	4,6	0,1	1,2	0,4	0,0	85,5
2030	2,9	4,4	1,5	0,0	0,1	1,2	0,4	0,0	89,5
2031-2039	3,0	4,0	1,5	0,0	0,1	1,2	0,4	0,0	89,9
2031-2039*	3,0	4,0	1,5	4,6	0,1	1,2	0,4	0,0	85,3
2040-2050	3,0	4,0	1,5	0,0	0,1	1,2	0,4	0,0	89,8
2040-2050*	3,0	4,0	1,5	4,6	0,1	1,2	0,4	0,0	85,2
Comments		Based on simulation model of topside process. Includes contribution from PM	Based on Statoil PE experience from other fields on NCC		Only unavailability of offshore loading caused by weather problems or delayed shuttle tanker is concidered.	External power supply: Case with spare trafos for FPSO and for power host	Authority-imposed reductions, Strike/lock-out, Weather problems, Safety/emergency preparedness requirement, Others		

Estimates on the overall delta losses for all alternative power concepts are given in table 4.3

Table 4-3 Overall delta losses for alternative power concepts

	Delta PE (%)
Case 1a	1.0
Case 1b	1.3
Case 1c	1.3
Case 1d	1.3
Case 1e	0.5
Case 2	1.0
Case 3	1.0

More details behind the results in Table 4.3 are given in App C.

5 Schedule

The Master Schedule for base case is given in section 2.3.

Below are schedule consequences compared to the overall base case milestones identified for each of the defined power concepts.

Table 5-1Schedule consequences

Case		description	schedule consequences
Locally produced power and heat			
Case 0	**a**	Offshore gas turbines	na
	b	Offshore gas turbines Prepared for future HVAC import for electrification of electrical power consumers	No schedule consequences for DG milestones. This case will be less matured than base case at DG2
Electrification of electrical power consumers			
Case 1	**a**	Power from shore HVDC Separate power host for conversion into HVAC on the field	Risk for achievement of DG3 milestone due to TQ program. Knock on effect might postpone DG4 one year.
	b	Power from shore HVAC 50Hz shunt reactors/ series capacitor	Postponement of DG2 one year due to maturity of power transmission system. Expected DG4: 2023
	c	Power from shore HVAC 50Hz shunt reactors/ STATCOM	Not feasible
	d	Power from shore HVAC low frequency	Postponement of DG2 one year due to lack of maturity of power transmission system and floater design. Expected DG4: 2023
	e	Hywind / Offshore gas turbines HVAC	Assuming that Case 0b is selected in June 2016, while the Hywind wind park is selected later upon successful technical qualification. Larger part of FPSO adjustments for Case 1e needs to be taken as a modification project after start-up Expected DG4: 2022, start-up of wind park at a later stage
Electrification of electrical power consumers and gas injection train			
Case 2		Power from shore HVDC Separate power host for conversion into HVAC on the field	Ref case 1a, in addition changes on floater design. Expected DG4: 2023
Electrification of electrical power consumers, gas injection train and heat demand			
Case 3		Power from shore HVDC Separate power host for conversion into HVAC on the field	Ref case 1a, in addition changes on floater design. Expected DG4: 2023

6 Cost and economic analysis

6.1 Facility cost

Delta CAPEX estimates have been prepared for the electrification cases using internal CostcCalc estimating tools. The CAPEX estimates cover all project activities from Project Sanction (DG3) and up to and including commissioning/start-up (DG4). Exchange rates and other economic assumptions have been based on standard EPA assumptions.

As input to the floater CAPEX estimates, delta weight estimates have been prepared for both the FPSO and the Power host solutions. Aker weight estimates, MEL and Plot Plans delivered in March 2016 are basis for case 1. For case 2 and 3, internal master equipment lists are prepared followed by layout assessments regarding available space for additional equipment. For the FPSO, it is assumed that future spaces on topside modules and risers spare slots in turret are utilized to accommodate additional equipment. References for the HVDC equipment weights for cases 1, 2 and 3 are Aker (ABB), Johan Sverdrup Phase 1 and Phase 2, respectively.

Table 6-1 Platform delta weight

Platforms delta weight (tonnes)	**Case 1 a**	**Case 1 b**	**Case 1 e**	**Case 2**	**Case 3**
FPSO	-615	-615	930*	604	949
Power Host	7 564	-		10 298	11 993
Total	**6 949**	**-615**	**930**	**10 902**	**12 942**
Estimate Class	B/A	A	A	A	A

*Note, the FPSO weights are underestimated as they are based on that all required modifications are made onshore as part of the main project.

The estimates can be considered as class A/B estimates. Class B estimates have an uncertainty of +/-40%.
For all cases there is assumed DG4 in 2022.

Table 6-2 Facility costs

Facilities CAPEX (2016 MNOK)	**Case 1 a**	**Case 1 b**	**Case 1e**	**Case 2**	**Case 3**
FPSO	- 760	- 760	1 082*	587	857
Power Host	3 801	na	na	4 798	5 499
Subsea	2 724	3 577	Incl below	3 260	3 618
Onshore	1 881	1 141	na	2 165	2 722
Wind park	na	na	1 350	na	na
Total	**7 646**	**3 958**	**2 432**	**10 810**	**12 695**
Estimate Class	B/A	A	A	A	A

*Note, the FPSO costs are underestimated as they are based on that all required modifications are made onshore as part of the main project.

Pending on installation methodology the fiber optic cable may be installed simultaneously with one of the power cables from shore. The fiber optic cable end will then be laid down outside the power host location for subsequently pick up, splicing and laying to the umbilical riser base at the FPSO in an separate operation. This might reduce the subsea estimate with approximately 100 MNOK.

A 3rd party CAPEX estimate prepared by Pöyry (Rambøll), is approximately 30% lower than the Statoil CAPEX estimate. The main contributor to this deviation seems to be the HVDC equipment cost both for the platform and onshore estimates. Statoil's experience numbers/rates are mainly based on recent detailed information from the Johan Sverdrup project and from power from shore studies of March 2016. A "normalisation" has been prepared by Statoil to adjust the Rambøll estimates with the information Statoil has on the HVDC equipment. Based on the normalisation, the deviation is reduced to 17%. Since Rambøll does not include inflation in their CAPEX estimates, the comparison has been made for estimates in real terms (hence lower Statoil estimates compared to the summary table with nominal CAPEX).

Table 6-3 Comparison with Rambøll cost estimates

Case 1a (constant MNOK)	Statoil	Rambøll	Diff	% Diff
Subsea	2 622	2 660	-38	-1 %
Platform	2 983	1 222	1 761	59 %
Onshore	1 853	1 109	744	40 %
Total	**7 458**	**4 991**	**2 467**	**33 %**

Case 1a Normalized (constant MNOK)	Statoil	Rambøll	Diff	% Diff
Subsea	2 622	2 660	-38	-1 %
Platform	2 983	1 902	1 081	36 %
Onshore	1 853	1 626	227	12 %
Total	**7 458**	**6 188**	**1 270**	**17 %**

6.2 Drilling and well cost

For the drilling and well cost estimate basis reference is made to section 8. Recent improvements related to Skrugard North and Drivis are adjusted for, giving a total drilling and well cost of 16133 MNOK (2015NOK) for the 31 wells.

6.3 OPEX

OPEX for all evaluated alternatives has been established based on the OPEX estimates used for concept selection. In the below table the OPEX for all evaluated power concepts are given.

Table 6-4 Operating expenses

2016NOK	OPEX MNOK/Year
Case 0a	1572
Case 0b	1572
Case 1a	1767
Case 1b	1683
Case 1c	1683
Case 1d	1708
Case 1e	1611
Case 2	1845
Case 3	1965

Further information including beak down of the OPEX is given in App D.

6.4 Electricity and CO_2 cost

The electricity cost is composed of the electricity price and the grid fee. Nordpool price is assumed, priced at 37 EUR/MWh in 2023 and increasing to 50 EUR/MWh in 2039 (flat thereafter), see **Error! Reference source not found.**. The grid fee contains two sub-elements: the fixed fee of NOK 230/kW, and the variable element (assumed 10%) of the electricity price, which both total an average of MNOK 13/year.

The CO_2 cost consists of two elements, the CO_2 quota and the CO_2 tax.

The electricity and CO2 costs are given in [3].

6.5 Economic analysis

The abatement cost is the ratio of delta NPV of costs/income (NOK) to PV of CO_2 reduction (Ton). In these calculations the CO_2 tax saved is excluded from the net costs. The abatement cost formula is given in Figure 6-1.

$$AC = \frac{\Delta NPV\ between\ the\ compared\ alternatives\ (excl.CO_2\ fee)}{Discounted\ \ CO_2\ \ reduction}\left[\frac{NOK}{ton\ reduced\ CO_2}\right]$$

Figure 6-1 Abatement cost formula

CAPEX, OPEX, production efficiency, production, CO_2 emissions, electricity cost, etc. has been established for all cases in order to enable economic analyses of the different power concept alternatives. Detailed overview of input and result of the abatement cost calculations is given in [3].

Results from the economic evaluations are given in Table 6-5 Costs and economy.

Table 6-5 Costs and economy

2016NOK	Delta Capex (BNOK)	Delta Opex** (MNOK/yr)	Abatement cost *** 8% discount rate (NOK/tonnCO_2)	Delta NPV **** 8% a.t. (MNOK)	Delta **** BE (USD/bbl)
Case 0a*	57.5	1 572	-	12 360	44
Case 0b	0.05	0	-	-10	0
Case 1a	7.6	210	10 500	-1 900	6
Case 1b	4.0	120	6 500	-2 150	6
Case 1c	NA - not feasible				
Case 1d	NA - high cost/losses				
Case 1e	2.4*****	40	7 600	-600	2
Case 2	10.8	300	8 700	-3 650	11
Case 3	12.7	430	7 150	-4 250	13

*Reference –actual numbers, not delta numbers or reduction numbers
** Including CO_2 and electricity cost
*** Assuming power from shore is green energy
**** One year delay of DG4 applied on Case 1b, 2 and 3.

****** Note, the FPSO costs are underestimated as they are based on that all required modifications are made onshore as part of the main project

The current base case power concept shows the highest NPV and lowest breakeven. None of the alternative power concepts show competitive abatement costs. A break-down of the abatement cost is given in Figure 6-2 and Figure 6-3 for 8% and 5% discount rates respectively, showing that CAPEX is the main contributor to the high abatement cost level.

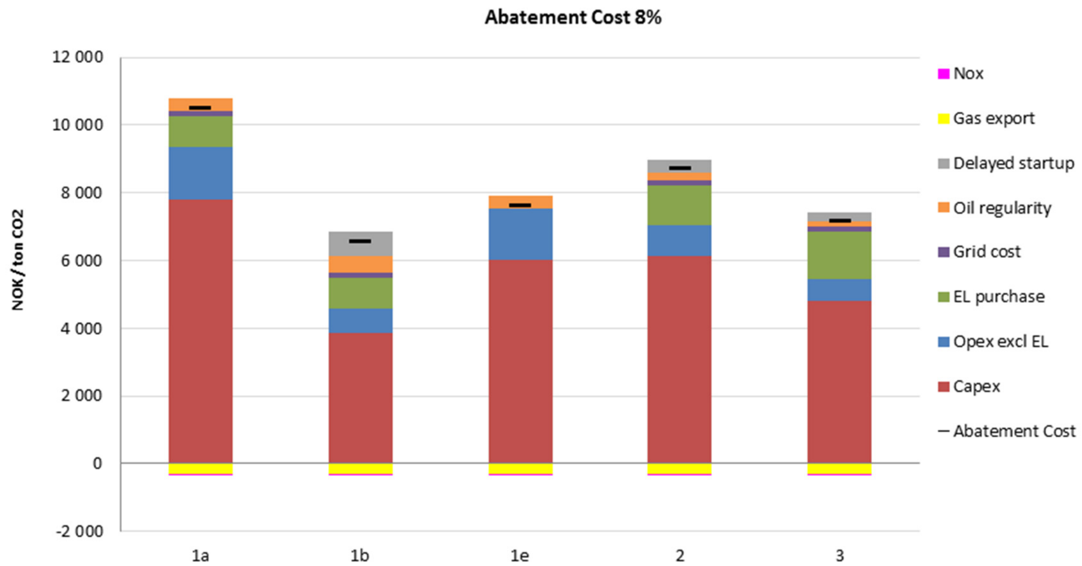


Figure 6-2 Abatement costs at 8% discount rate

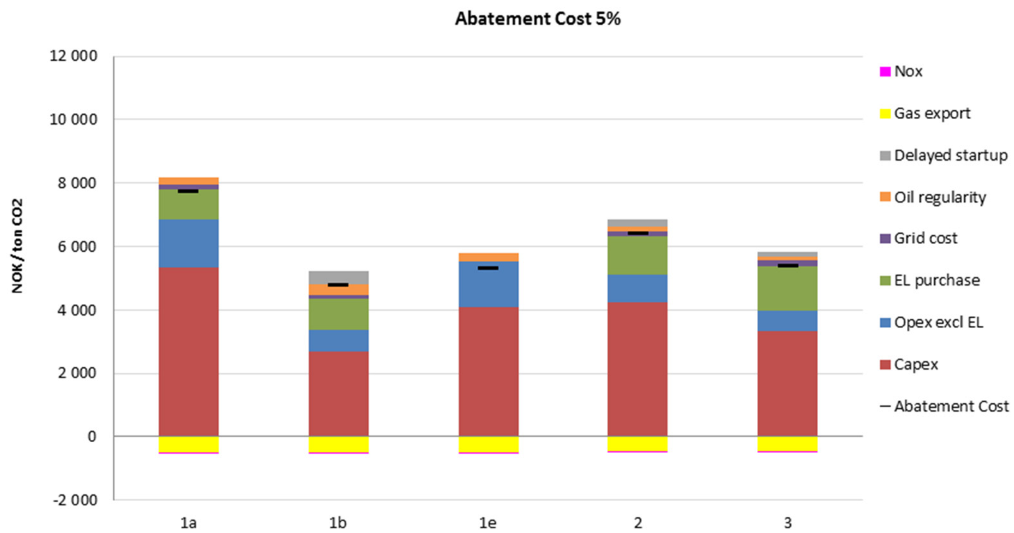


Figure 6-3 Abatement costs at 5% discount rate

Based on the abatement cost the HVAC technology, case 1b, is looked upon as the main challenger to the current base case. A tornado diagram for case 1b is presented below.

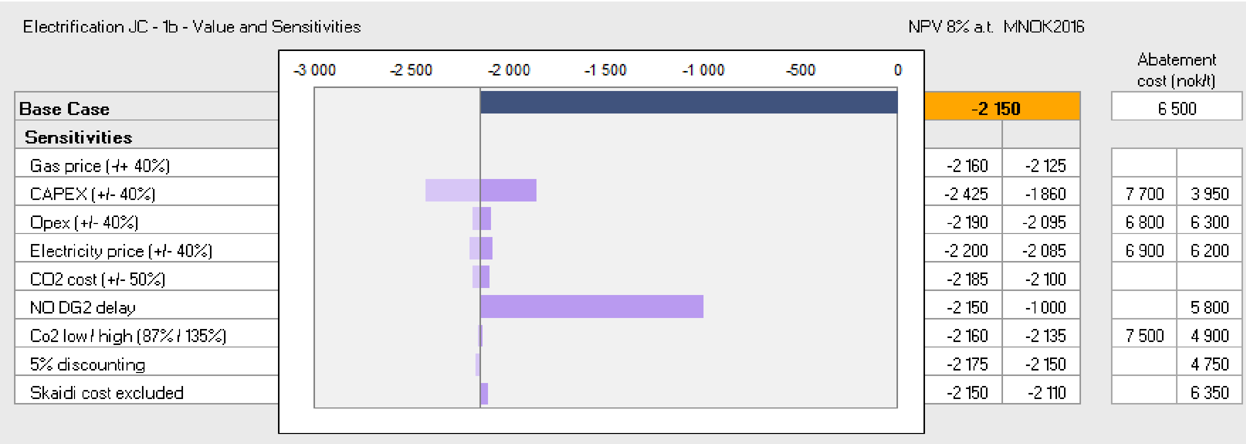


Figure 6-4 Economic evaluation – tornado (Case 1b)

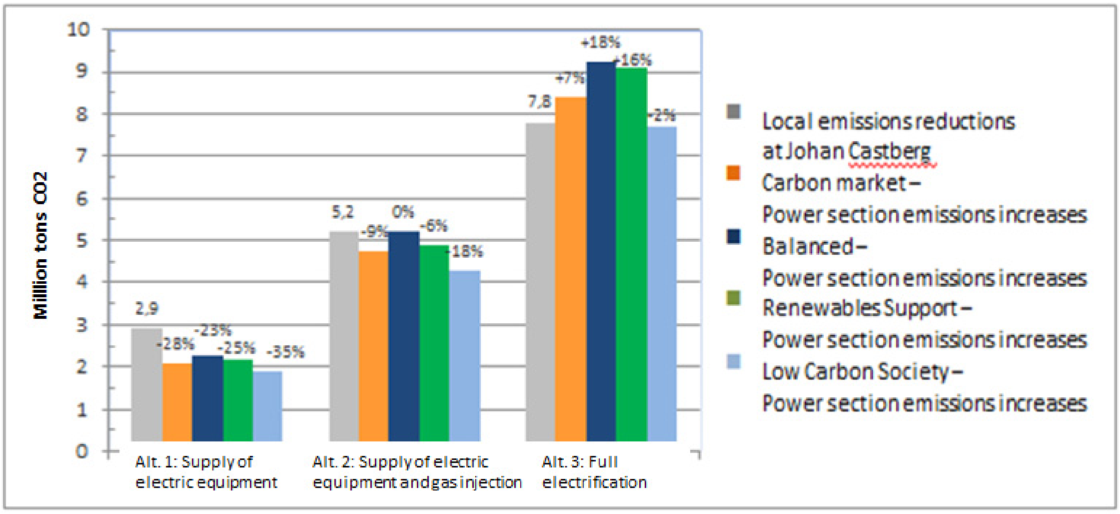
7 External evaluations on global climate effect and abatement cost

7.1 Global climate effect

Pöyry has chosen to use future EU energy and climate policy as the basis for scenario design. In all scenarios they assume that EU and the member states will initiate measures designed to achieve their energy policy objectives for 2030 (which Norway has also adopted), and that the EU maintains its long-term ambition of a virtually emission-free power sector in 2050. The scenarios are defined by which measures the authorities actually implement to achieve these energy and climate policy goals and ambitions, and can be summarized as follows (see also the figure below):

- **Scenario A - The Carbon Market:** the European emissions trading system (EU ETS) is the only driver for decarbonisation
- **Scenario B - Balanced:** with a more varied use of instruments, relying on both a relatively strong emissions trading system and direct support for renewable energy
- **Scenario C - Renewable Support**: where decarbonisation is incentivised through various national energy policy mechanisms, such as capacity markets and direct support for renewable energy, and where the emissions trading system plays a more modest role
- **Scenario D - The Low Carbon Society:** where the varied use of instruments in the Balanced scenario is combined with a stronger 2050 ambition for decarbonisation

In a Norwegian perspective, the power supply from onshore comes from renewable sources. The local emissions impact of electrification will therefore always be positive – gas production with CO_2 emissions offshore is replaced by zero emissions power generation onshore. Taking into account that the Norwegian electricity market is part of the European power market, the picture looks different. The Pöyry analysis show that parts of the local emissions cut will be offset by increased CO_2 emissions from the power sector in Europe since electrification will reduce electricity exports from Norway. The marginal increase in emissions in Europe due to increased demands, are largely covered by increased production from coal power plants and gas power plants. Renewables such as hydro, wind and solar produces the energy that flows to them, while other plants have to regulate. Response to demand increases will therefore come from available capacity in European thermal plants. The accumulated global climate impact of the electrification of Johan Castberg is in the range from -18% up to 35% depending on the electrification case and climate policy, i.e. -1.4 to 1.0 million tons of CO_2 accumulated over lifetime (see figure below).



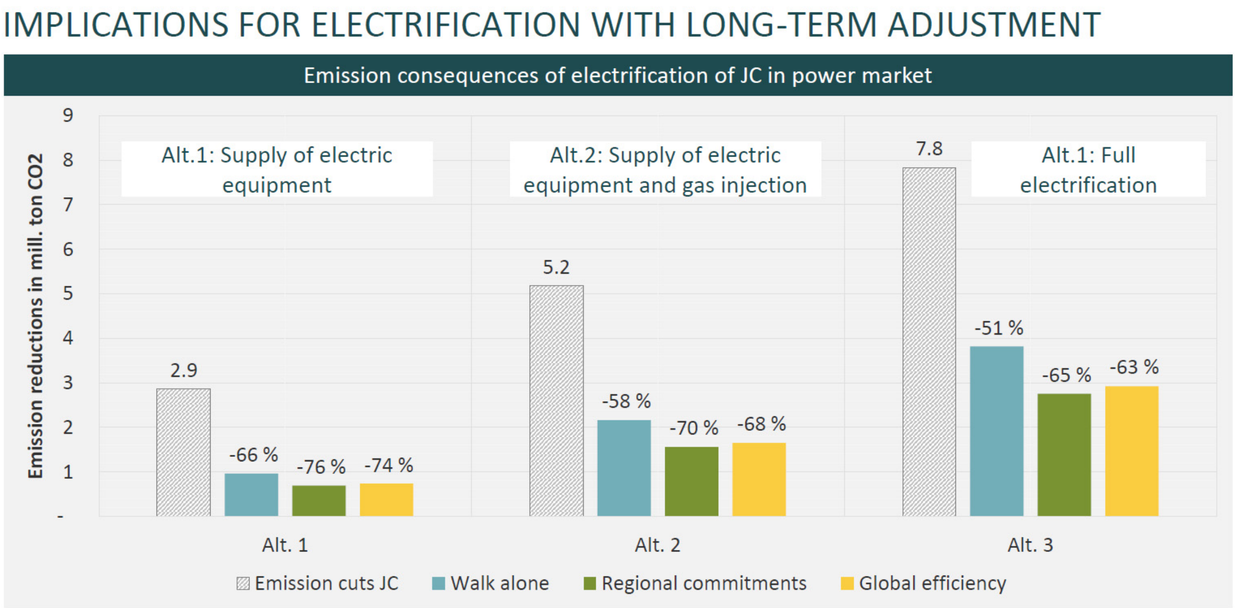
Thema evaluates the effect of electrification of Johan Castberg on Norwegian, European and global carbon emissions. The study takes into account that Norway is part of the European power system, and Norway's (and the Nordic's) power export and import opportunities.
The analysis is based on three policy scenarios with different degrees of fragmentation of European and international climate policies:

- **Walk alone:** In this scenario, climate policies are regionally fragmented (as today). Furthermore, different carbon policy mechanisms apply to different sectors within the EU (i.e., the EU Emissions Trading Scheme (EU-ETS) covers some sectors, while the Effort Sharing Decisions (ESD) covers the other sectors).
- **Regional Commitments:** In this scenario, they assume a joint market for all carbon emissions in Europe, i.e., the EU-ETS and ESD are merged. Globally, however, there is no international carbon market or cooperation, although other regions apply carbon policies that are less strict than those of Europe.
- **Global efficiency:** This scenario is based on the idea of a global climate agreement, with a high degree of global cooperation and joint mechanisms, and in particular, a global CO_2 price.

For all policy scenarios Thema assumes that the world is pursuing the 2-degree target, although at different paces. The different scenarios portray different developments around carbon prices, fuel prices, developments of renewable energy (RES) and thermal capacities in Europe and world-wide (influencing technology costs), nuclear policies, CCS developments, and the degree of interconnection between the Nordic and the Continental power markets.

Power demand from Johan Castberg (JC) can be covered by increased generation from existing power generation, or by generation from new capacity. Since electrification of JC represents an expected and permanent change in power demand, the increase in demand will affect the long-term capacity. Hence, Thema assumes that the demand will mainly be covered by new generation. The markets are dynamic and competitive and should be expected to adjust to changes in market conditions continuously. Thema expects that the marginal investments are a mix of renewable generation and gas power investment, where the shares differ between the scenarios.

The figure below shows the emission cuts at Johan Castberg compared to the corresponding emission increase from the power market in the different policy scenarios and for the different electrification alternatives. In all cases, providing electricity from shore will reduce the overall carbon emissions (demand for allowances) from the power and petroleum sector. The net reduction ranges from approximately 75% to 50% of the local emission reduction at JC depending on electrification case and climate policy scenario.



Sum up: Power used for electricity production is not 100% renewable. Electrification of Johan Castberg will result in an increase in emissions from the power generation industry. The value of net reduction/increase in emissions depends on the scenario and the degree of electrification as well as assumptions about new investments.

7.2 Abatement cost

Both Pöyry and Thema discuss value of electrification in terms of abatement costs. The value of emission reductions from electrification of JC depends on the assumed policy scenario. JC electrification is an efficient climate measure if the abatement cost of electrification is lower than the net present value of the carbon price.
Thema concludes that an abatement cost above 1000 NOK/ton CO_2 is not likely to be socio-economic efficient.

Pöyry together with Rambøll, have based on external and internal (Statoil/JC) facts and figures, calculated the abatement costs of electrification of JC. Their conclusion is that electrification of JC is not a socio-economically profitable abatement measure:

Based on the assumption that the electricity is 100 % green the abatement costs is calculated to 3900 to 5300 NOK per tonne of local CO_2 emission reduction, depending on the choice of electrification alternative and the electricity market assumptions. Electrification will reduce local emissions, but cost of electrification of JC is high, and as a result the abatement cost will be much higher than the CO_2 cost. Sensitivities do not change this conclusion. Electrification of Johan

Castberg is not a cost-effective abatement measure in a local perspective, and this conclusion is strengthened when considering European power sector emissions.

8 References

[1]	PM050-PMS-054	Concept selection summary report (Dec-2015)
[2]	Johan Castberg power concept selection summary report_Power demand_Emissions_Intensity_PARTNER VERSION_03.06.2016	Excel spreadsheet provided on L2S together with this report
[3]	Johan Castberg power concept selection summary report_Abatement Cost Calculations_PARTNER VERSION_03.06.2016	Excel spreadsheet provided on L2S together with this report
[4]	UPS-2015149-R04	Unitech Report, HVDC Reliability assessment

App A CO_2 sensitivities

The CO_2 emissions at the FPSO are directly related to the power (and heat) demand. Changes in the demand due to design development will lead to changes in the estimated CO_2 emissions. Additionally, the CO_2 emissions in case 0a/b are quite sensitive to the average operating hours the el. load is covered by one of the LM2500+G4 turbines running on high load and high efficiency rather than both running on low load and low efficiency.

The expected CO_2 emissions presented in Section 2.5.1 are based on an average turbine efficiency of 32.6% and expected average power demand including margins for (expected) project growth. A low and a high CO_2 sensitivity case are presented in the figure below. The low case is based on running 2 turbines only while off-loading with a resulting average turbine efficiency of 35 – 36%, and power demand as for the expected case. The high case is based on running 2 turbines at all times on low load with an average turbine efficiency of 29% as well as adding 3 MW (a 12.5% increase) in the average el. power demand for all years for further (unexpected) growth.

Via energy efficiency measures in the design phase and a power management system in operation, the target is to maximize operating hours at high efficiency.

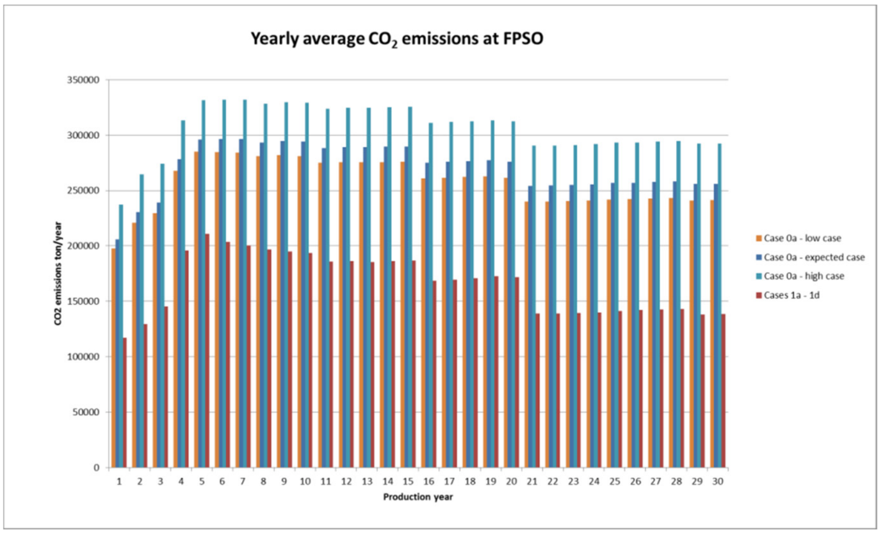


Figure C-1 CO_2 emissions

The effect on the overall energy efficiency and CO_2 intensity is given in the table below.

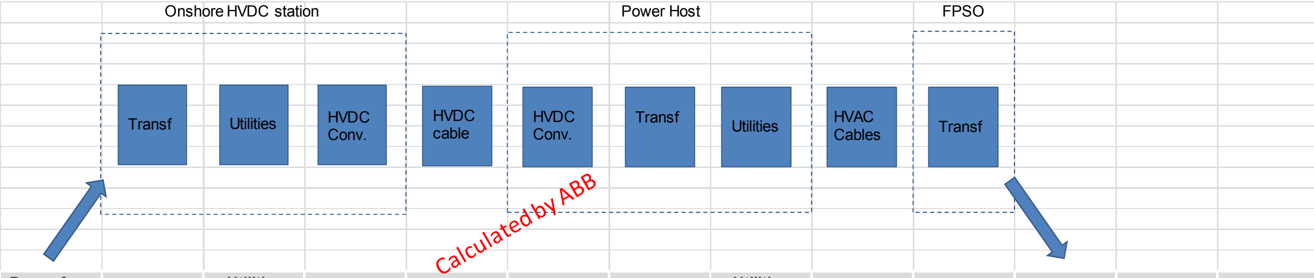
Table C-1 Energy efficiencies and CO_2 intensities

Average over the lifetime	Energy efficiency (%)			CO_2 intensity (gCO_2/kWh)			CO_2 intensity (kg CO_2/boe)		
	Low case	Expt. case	High case	Low case	Expt. case	High case	Low case	Expt. case	High case
Case 0a	67	64	58	309	325	357	13.4	14.1	16.0
Case 1a-1c	79	79	79	198	198	192	8.6	8.6	8.6
Case 1d	73	73	73	198	198	192	8.6	8.6	8.6
Case 1e	77	77	76	271	271	275	11.8	11.8	12.3
Case 2	82	82	82	106	106	103	4.6	4.6	4.6
Case 3	80	80	80	NA	NA	NA	NA	NA	NA

In case 1e, the Hywind case, the load of the LM2500+G4 turbines will vary with the availability of wind power and the power demand. The average efficiency is estimated to 29.9% and this number is used for all the cases.

App B Overview of losses in the power systems

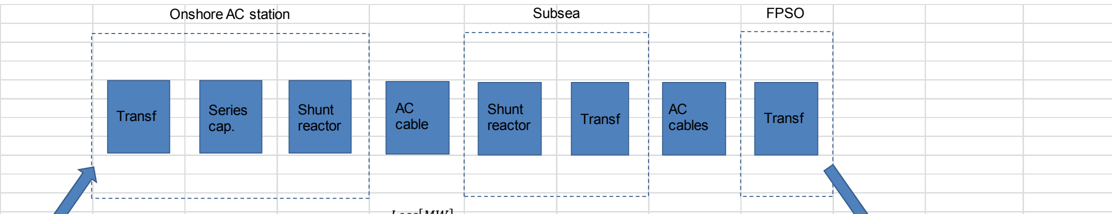
HVDC via Power Host



Power from grid	Transf.	Utilities (Aibel input)	HVDC Conv.	DC cable	HVDC Conv.	Transf.	Utilities (Aker input)	AC cables	Transf.	Load	Total losses	Efficiency
25,3MW	0,03MW / 0,1 %	1,4 MW	0,7 MW / 2,8 %	0,7 MW / 3,2 %	0,9 MW / 3,8 %	0,03 MW/0,1%	1,7 MW	0,05 MW /0,3 %	0,04 MW / 0,2 %	**20 MW**	**5,3 MW/21%**	**79 %**
49,4 MW	0,2 MW / 0,4 %		1,4 MW / 2,8 %	2,9 MW / 6,1 %	1,7 MW / 3,8 %	0,1 MW/ 0,3 %		0,2 MW / 0,5 %	0,2 MW / 0,4 %	**40 MW**	**9,4 MW/19%**	**81 %**
75,6 MW	0,3 MW / 0,4 %		2,1 MW / 2,8 %	6,8 MW / 9,4 %	2,5 MW / 3,8 %	0,3 MW/ 0,5 %		0,5 MW / 0,8 %	0,4 MW / 0,6 %	**60 MW**	**15,6MW/20,6%**	**79,4 %**
89,1MW	0,4 MW / 0,4 %		2,5 MW / 2,8 %	9,4 MW / 12,4 %	2,8 MW / 3,8 %	0,3 MW/ 0,4 %		0,5 MW / 0,8 %	0,4 MW / 0,6 %	**70 MW**	**19,1MW/21,4%**	**78,6 %**

Calculated by ABB

HVAC

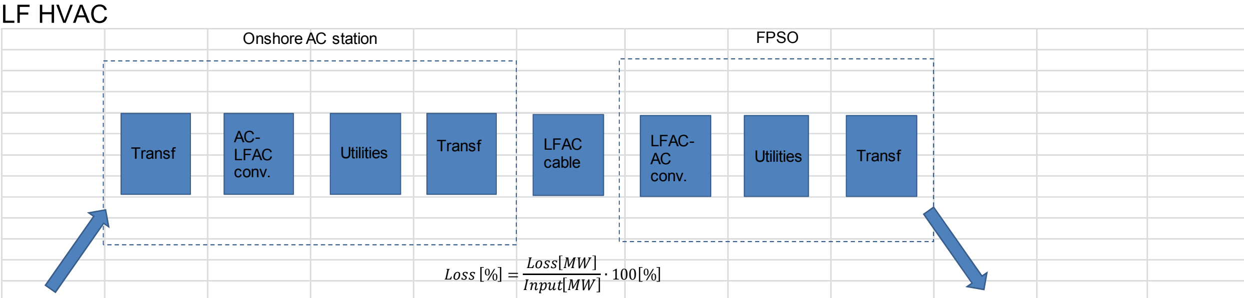


$$Loss\,[\%] = \frac{Loss[MW]}{Input[MW]} \cdot 100[\%]$$

Power from grid	Transf.	Series cap.	Shunt reactor	AC cable	Shunt reactor	Transf.	AC cables	Transf.	Load	Total losses	Efficiency
27,1 MW	0,03 MW / 0,1 %	0,00 MW / 0,0 %	0,53 MW / 2,0 %	6,1 MW / 23,1 %	0,33 MW / 1,6 %	0,02 MW / 0,1 %	0,01 MW / 0,0 %	0,04 MW / 0,2 %	**20 MW**	**7,1 MW / 26,1 %**	**73,9 %**
49,1 MW	0,15 MW / 0,3 %	0,02 MW / 0,0 %	0,53 MW / 1,1 %	7,7 MW / 16,0 %	0,33 MW / 0,8 %	0,12 MW / 0,3 %	0,03 MW / 0,1 %	0,16 MW / 0,4 %	**40 MW**	**9,1 MW / 18,5 %**	**81,5 %**
72,6 MW	0,29 MW / 0,4 %	0,05 MW / 0,1 %	0,53 MW / 0,7 %	10,7 MW / 15,0 %	0,33 MW / 0,5 %	0,24 MW / 0,4 %	0,08 MW / 0,1 %	0,36 MW / 0,6 %	**60 MW**	**12,6 MW / 17,4 %**	**82,6 %**
84,9 MW	0,42 MW / 0,5 %	0,08 MW / 0,1 %	0,53 MW / 0,6 %	12,6 MW / 15,1 %	0,33 MW / 0,5 %	0,35 MW / 0,5 %	0,10 MW / 0,1 %	0,42 MW / 0,6 %	**70 MW**	**14,9 MW / 17,5 %**	**82,5 %**

- Transformer losses based on ABB's figures (HVDC)
- Shunt reactor losses assumed to be 4.5 kW/MVAr
- Series capacitor losses uncertain, assumed to be 0.1 % at full load
- AC cable losses will depend on actual cable temperature
  - 50 °C conductor temperature assumed here

LF HVAC



$$Loss\,[\%] = \frac{Loss[MW]}{Input[MW]} \cdot 100[\%]$$

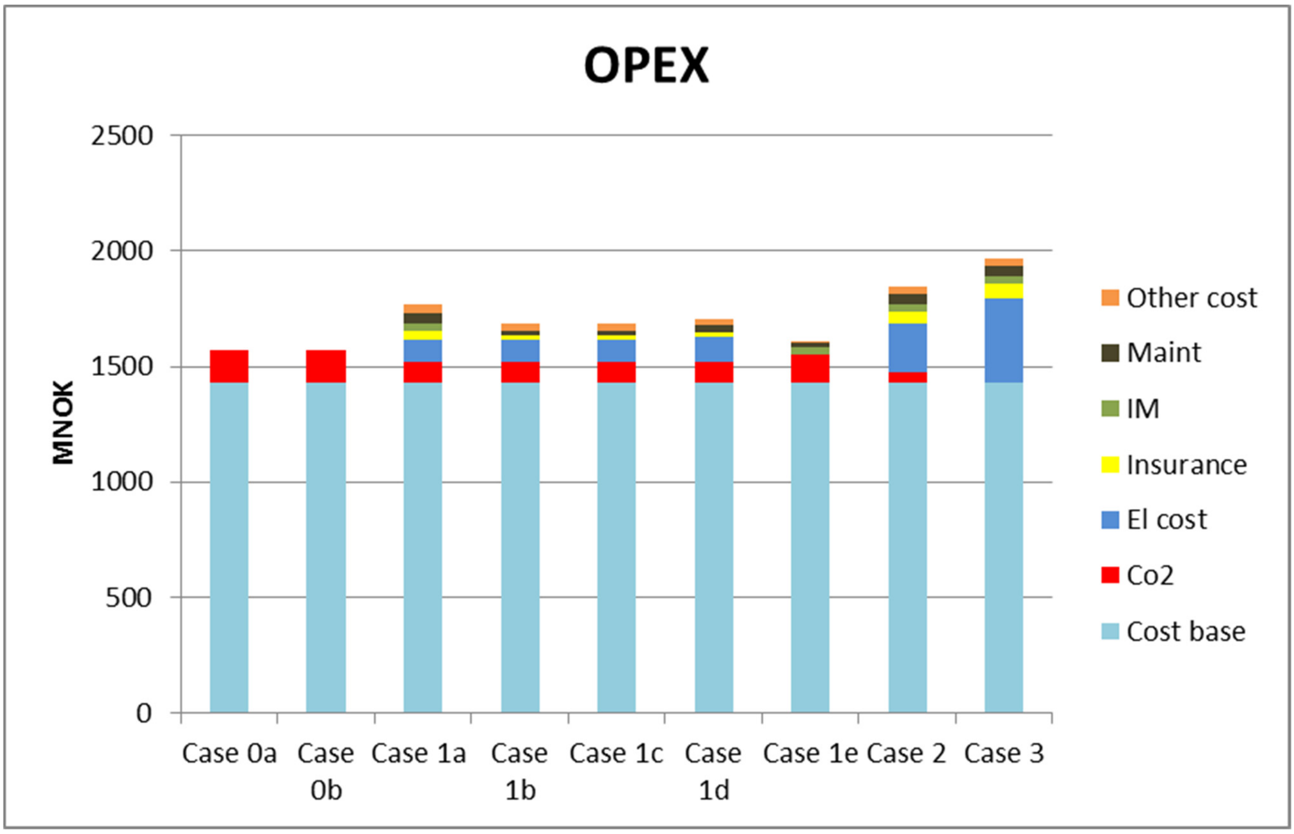
Power from grid	Transf.	AC-LFAC conv.	Utilities	Transf.	LFAC cable	LFAC-AC conv.	Utilities	Transf.	Load	Total losses	Efficiency
29,9 MW	0,03 MW / 0,1 %	2,0 MW / 6,6 %	2,1 MW / 7,5 %	0,05 MW / 0,2 %	2,0 MW / 7,8 %	1,6 MW / 6,6 %	2,1 MW / 9,5 %	0,04 MW / 0,2 %	**20 MW**	**9,9 MW / 33,0 %**	**67,0 %**
58,1 MW	0,23 MW / 0,4 %	3,8 MW / 6,6 %	2,1 MW / 3,9 %	0,21 MW / 0,4 %	6,5 MW / 12,5 %	3,0 MW / 6,6 %	2,1 MW / 5,0 %	0,16 MW / 0,4 %	**40 MW**	**18,1 MW / 31,1 %**	**68,9 %**
89,7 MW	0,36 MW / 0,4 %	5,9 MW / 6,6 %	2,1 MW / 2,5 %	0,49 MW / 0,6 %	14,0 MW / 17,3 %	4,4 MW / 6,6 %	2,1 MW / 3,4 %	0,36 MW / 0,6 %	**60 MW**	**29,7 MW / 33,1 %**	**66,9 %**
106,3 MW	0,43 MW / 0,4 %	7,0 MW / 6,6 %	2,1 MW / 2,1 %	0,58 MW / 0,6 %	18,6 MW / 19,3 %	5,1 MW / 6,6 %	2,1 MW / 2,9 %	0,42 MW / 0,6 %	**70 MW**	**36,3 MW / 34,2 %**	**65,8 %**

- Transformer losses based on ABB's figures (HVDC)
- Shunt reactor losses assumed to be 4.5 kW/MVAr
- AC-LFAC converters assumed to have same losses as sum of rectifier and inverter station losses in ABB's HVDC case
  - Utilities assumed to draw 1.5 times that of onshore HVDC station in ABB's HVDC case
- AC cable losses will depend on actual cable temperature
  - 50 °C conductor temperature assumed here

App C Production efficiency

	Locally produced power and heat				
			Technical		**DELTA PE impact**
Case 0	**a**	Offshore gas turbines	3x turbine		Reference case
	b	Offshore gas turbines Prepared for future HVAC import for electrification of electrical power consumers	3x turbine		0
	Electrification of electrical power consumers				
Case 1	**a**	Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host FPSO: 1 turbine		Loss 1,0 % • Grid • Power host
	b	Power from shore, HVAC 50Hz shunt reactors/ series capacitor	Subsea FPSO: 1 turbine		Loss 1,3% • Grid • Subsea • TQP
	c	Power from shore, HVAC 50Hz shunt reactors/ STATCOM	Subsea		Loss 1,3% • Grid • Subsea • STATCOM at FPSO • TQP
	d	Power from shore HVAC low frequency	Subsea 2XHVDC on- and offshore		Loss 1,3% • Grid • Subsea • Complexity • TQP
	e	Hywind / Offshore gas turbines	3 turbines, battery		Loss 0,5 % • Control system complexity • TQP
	Electrification of electrical power consumers and gas injection train				
Case 2		Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host 3 X25MW boiler		Loss 1,0 % • Grid • Power host
	Electrification of electrical power consumers, gas injection train and heat demand				
Case 3		Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host Electric boilers		Loss 1,0% • Grid • Power host

App D OPEX


OPEX
MNOK
2500
2000
1500
1000
500
0
Case 0a
Case 0b
Case 1a
Case 1b
Case 1c
Case 1d
Case 1e
Case 2
Case 3
Other cost
Maint
IM
Insurance
El cost
Co2
Cost base

Locally produced power and heat				
			Technical	**OPEX**
Case 0	**a**	Offshore gas turbines	3x turbine	OPEX 1572 MNOK
	b	Offshore gas turbines Prepared for future HVAC import for electrification of electrical power consumers	3x turbine	OPEX 1572 MNOK
Electrification of electrical power consumers				
Case 1	**a**	Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host FPSO: 1 turbine	OPEX MNOK 1767 • Electricity cost • Maintenance onshore and PH • Ice Management • Reduced CO_2 • Reduced turbine maintenance
	b	Power from shore, HVAC 50Hz shunt reactors/ series capacitor	Subsea FPSO: 1 turbine	OPEX MNOK 1683 • Electricity cost/power loss 10% • Maintenance on-and offshore • Reduced CO_2 • Reduced turbine maintenance
	c	Power from shore, HVAC 50Hz shunt reactors/ STATCOM	Subsea	OPEX MNOK 1683 • Electricity cost/power loss 10% • Maintenance on-and offshore • Reduced CO_2 • Reduced turbine maintenance
	d	Power from shore HVAC low frequency	Subsea 2XHVDC on- and offshore	OPEX MNOK 1708 • Electricity cost/power loss 20% • Maintenance on-and offshore • Reduced CO_2 • Reduced turbine maintenance
	e	Hywind / Offshore gas turbines	3 turbines, battery	OPEX MNOK 1611 • O&M of wind park, boilers and batteries • Ice management • Reduced CO_2
Electrification of electrical power consumers and gas injection train				
Case 2		Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host 3 X25MW boiler	OPEX MNOK 1845 • High electricity cost • Electric drive of compressors • Boiler maintenance • Ice management • Reduced CO_2 • Reduced turbine maintenance
Electrification of electrical power consumers, gas injection train and heat demand				
Case 3		Power from shore, HVDC Separate power host for conversion into HVAC on the field	Power Host Electric boilers	OPEX MNOK 1965 • Very high electricity cost • Electric drive of compressors el. boiler • Reduced CO_2 • Reduced turbine maintenance • High number of electric components • Ice management