

Effective Concepts for Supplying Energy to a Large Offshore Oil and Gas Area under Different Future Scenarios

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Different possibilities were assessed to supply energy to a large offshore oil and gas area in the North Sea. The concepts studied involved: (i) onsite power generation by means of simple gas turbine cycles, (ii) full electrification of the plants with power taken from the onshore grid, and (iii) a hybrid solution where power can be either generated onsite or taken from the onshore grid. The analysis included 37 y of the facilities' lifetime and was based on process simulations of the various concepts. The effect of the offshore area electrification was simulated through a model of the power system. The integration of process and power system modelling contributes to the originality and completeness of the analysis. The environmental impact of the concepts was evaluated in terms of cumulative CO₂ emissions. The relative economic cost was also assessed to provide a complete picture. The results showed that the advantage of a specific concept over the others was significantly influenced by the future energy policies and the magnitude of the initial investment cost.

1. Introduction

The processes necessary to extract gas and oil from underground and transport them onshore require significant amount of energy, leading to CO₂ emissions. An increased environmental awareness and the relative implementation of mitigation policies, constituted the driving force to investigate effective concepts to efficiently supply energy to offshore installations. Different approaches have been considered and assessed in the literature to address the issue. Nguyen et al. (2016) investigated several measures for increasing energy efficiency, concluding that the extent of the saving potentials is case-specific. Nord and Bolland (2013) showed the effectiveness of an offshore steam bottoming cycle. Pierobon et al. (2014) demonstrated that an organic Rankine cycle is also an attractive technology for offshore applications. Two additional approaches consisted of the plants electrification with power from the onshore grid (Nguyen et al., 2016) and of the integration of renewable energy sources to local power generation (He et al., 2010). The actual effectiveness of a concept should be measured as the capability to reduce CO₂ emissions while meeting economic and energy requirements, and should encompass the entire lifetime of the facilities considered. The main aim of this work was to analyse the effectiveness of different concepts to supply power and heat to a specific large offshore area and to compare them under different future scenarios. The offshore area selected as case study for this work was the Utsira area, located in the Norwegian sector of the North Sea and constituted of four production fields with the related offshore facilities: Edvard Grieg, Ivar Aasen, Gina Krog and Johan Sverdrup. The presence of different facilities, the significant energy demand and the possibility to electrify the plants made the Utsira area very interesting as case study. Process simulations relative to the different operating conditions during the plant's lifetime were carried out, based on specific process models. The process models were integrated with a detailed model of the power system affected by the possible electrification of the area. This approach allowed giving a reliable estimation of CO₂ emissions associated with power taken from shore (PFS), avoiding simplifications commonly used in such analyses; e.g. PFS accounted for with a fixed CO₂ emission factor.

2. Methodology

2.1 Input parameters to the analysis

The plants of the Utsira area have power and heat requirements to operate the production facilities. Power is mainly needed for pumps and compressors. Heat is mainly needed for oil stabilization, gas dehydration and fuel gas heating. The first step to assess the most effective options to operate the facilities was to quantify those energy requirements for the period considered in the analysis. During their lifetime, the facilities will be operating at several different conditions, in connection to the different stages of an oil field, i.e. early-life, peak and end-life production. Accordingly, this analysis took into consideration the different periods of the fields' lifetime, from 2022 until 2058 (last year of predicted production of Johan Sverdup facility). It should be noted that several platforms on the Utsira area are operating prior to year 2022 when PFS is phased in for Edvard Grieg, Ivar Aasen and Gina Krog. This paper assumed an ideal situation with an equal "start-up" of all the Utsira platforms in 2022. For this time span, power and heat demand profiles were retrieved from relevant field development reports of the facilities (Statoil, 2014) (see Figure 1). The lifetime CO₂ emissions were evaluated by calculating the emissions related to the local fuel usage and the proper emission factors related to PFS. The CO₂ emission factor (kg_{CO2}/kWh) to associate with PFS was an output of the power system model.

2.2 Concepts to supply energy to the offshore area

Concept 0 involved uniquely onsite power generation by means of simple GT cycles (see Figure 2-0a and 2-0b). The heat requirements were met by exploiting the thermal energy available in the exhaust GT gases. Two subcases were considered. Concept 0a represents the common practice in offshore fields, where each installation has an independent power generation system. Concept 0b assumed a perfect power integration of the Utsira area, that is, the possibility to exchange power in the form of electricity between the facilities. An advantage of the power integration consisted of the reduced number of GTs needed to meet power requirements, at the price of an investment to tie-in the platforms and of a coordinated development of the fields. Concept 0a required a total of 9 GTs (3 x GE LM2500+G4 and 6 x GE LM6000 PF) to cover the peak demand of power with a reasonable flexibility margin, while Concept 0b required 8 GTs (3 x GE LM2500+G4 and 5 x GE LM6000 PF). In both cases, an optimization process was implemented to define the optimal operation of the GTs during the plants lifetime. Maximum and minimum loads at which the GTs could operate were dynamically set, depending on the power and process heat requirements, and considering a flexibility margin in the case of unexpected trip of a gas turbine. A constrained optimization process then determined the optimum operating strategy to allocate the total load between the GTs so that the power and heat requirements were met at the minimum fuel consumption rate. A genetic algorithm was used to solve the optimization process.

Concept 1 involved the electrification of the offshore area with the possibility to access to PFS (see Figure 2-1). The Johan Sverdup facility was assumed as the power hub, getting power from the onshore grid and supplying to the other facilities according to their requirements. The process heat was provided by means of gas-fired water heaters and electric heaters. The heat requirements of Ivar Aasen and Gina Krog were considered to be negligible, according to the information available.

Concept 2 partially exploited the possibility of obtaining PFS, while simultaneously running GTs to meet the process heat requirements (see Figure 2-2). The same electrification framework was considered as that outlined for Concept 1. The number of GTs was evaluated as the minimum which was able to meet peak heat demand of the different facilities. A total of 3 GTs (1 x GE LM2500+G4 and 2 x GE LM6000 PF) was considered, accordingly. An optimization process was implemented to establish the share between onsite power generation and PFS which minimized the overall CO₂ emissions for each instance of the plants' lifetime. The calculation took into account off-design performance of the GTs and the emission associated with PFS in each year. A genetic algorithm was again used for the optimization process.

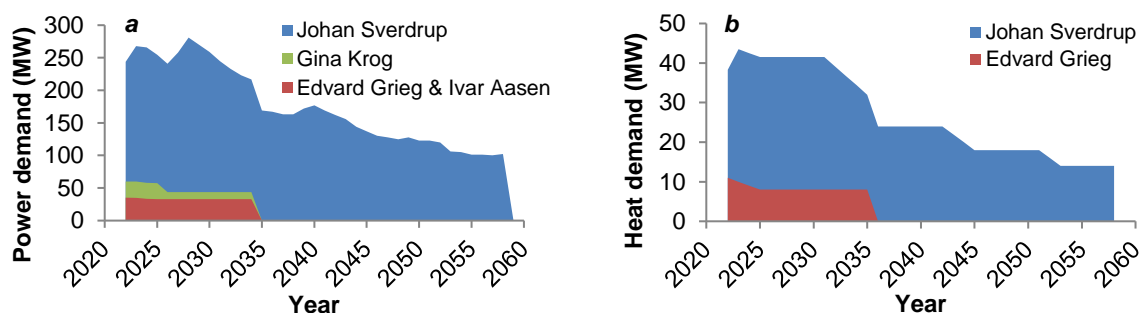


Figure 1: Power (1a) and heat (1b) demand profiles of the plants in the Utsira area (Statoil, 2014).

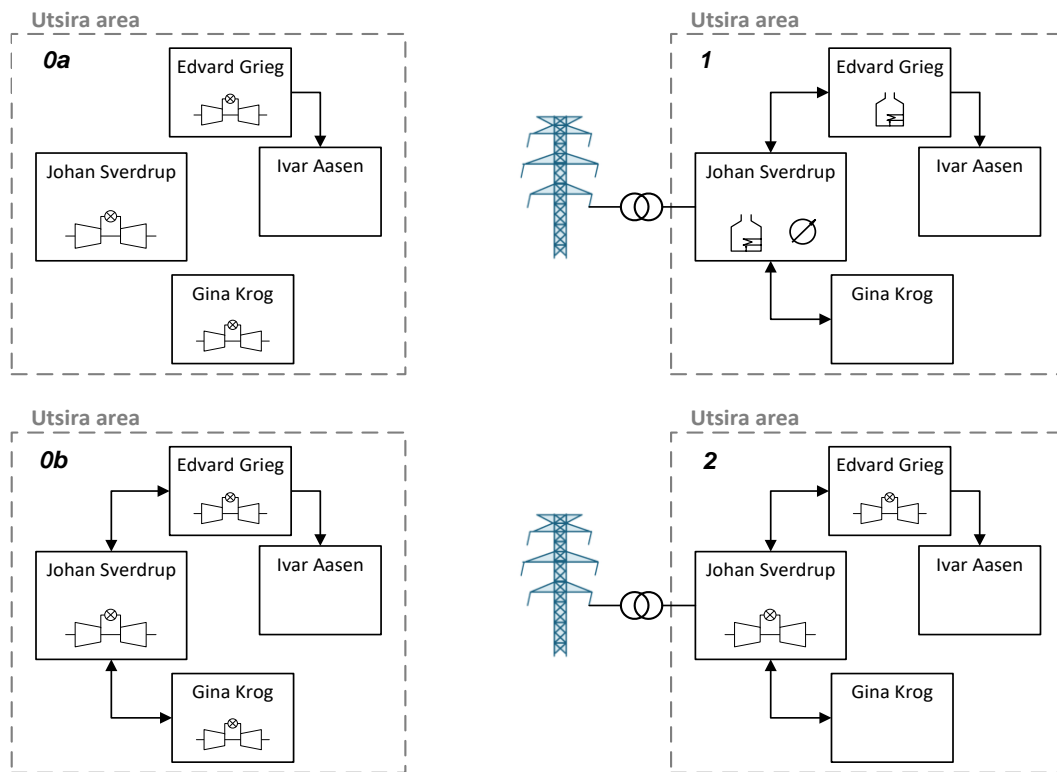


Figure 2: Simplified process schemes of the different concepts investigated to supply energy to the Utsira area.

2.3 Process modelling

The models of the power generation systems were developed in THERMOFLEX (Thermoflow Inc.), a fully-flexible program for design and off-design simulation of thermal systems. The GTs were modeled through a data-defined model based on the curves provided by the manufacturer. The waste heat recovery units (WHRUs) were modeled as a counter-flow vertical finned tube heat exchanger. The physical hardware design was defined and validated in accordance with industrial data. The gas-fired heaters were defined with an 85 % efficiency and air blowers were included into the model, with an isentropic efficiency of 80 %. Electric heaters assumed a 95 % efficiency factor. Two types of losses were considered for the PFS: transformer losses, accounted for by a 99 % transformer efficiency, and transmission losses, accounted for by a 11 % loss term.

2.4 Power system modelling

A power market model was used to simulate the Northern European power grid, which included Norway, Sweden, Finland, Denmark, Germany and the Netherlands. The objective of the power system model was to minimize the operating cost of supplying the total demand in the whole area, taking into account fuel costs, power plant characteristics, emission costs, while complying with the hourly energy balance, with the net transfer capacity (NTC) constraints and with the operational security standards (Farahmand, 2012). Key input parameters for the different types of thermal power plant (emission factors, energy efficiencies and energy conversion factors) were obtained from (IEA, 2011). The electrification power demand was added to the demand in the power system area that corresponds to Western Norway in the model. Today's situation regarding production capacity, demand and transmission constraints was a starting point for the simulations. The future development of the Northern European power system is subject to a high degree of uncertainty but most official projections and scenarios assumes a further expansion of wind and solar power. The scenarios from the EU-project e-HighWay2050 (e-Highway2050, 2015) were used as basis, resulting in a total wind + solar share of about 50 % in 2050 (total wind + solar capacity divided by peak load). A fixed hydro reservoir starting point was considered at the beginning of each year. In this work, the main outputs of the model were the marginal cost of power (i.e. the simulated spot price in the electrification area) and the marginal CO₂ emissions (i.e. increase in CO₂ emissions within the power system when adding electrification). The CO₂ emission factor to associate with PFS was then calculated as the marginal CO₂ emissions divided by the annual power supplied to Utsira area.

2.5 Economic analysis

The analysis spaced over a long-time span (nearly 40 y), thus it became important to discount the cash flows involved in the economic analysis. The value of each discounted cash flow (DCF_i) was then calculated, setting a discount rate equal to 7 % for all calculations. The annual cash flows were evaluated as the summation of the terms associated with (i) the offshore gas utilization to fuel onsite power generation (accounted for as a missing revenue), (ii) the cost of the onsite CO₂ emissions and (iii) the purchase of power from the onshore grid. The estimation of the capital investment (CAPEX) relative to each concept requires an extensive knowledge of the plants and a large amount of information. A different approach was therefore used. Concept 0a was selected as base case and a reasonable estimation of the capital investments for the major equipment related to power generation could be made (214 M\$), based on industrial data. The net present value (NPV) was calculated for this base case. For the other concepts, it was calculated the maximum capital investment (CAPEX_{max}) which would make the relative economic cost of that concept equal to the base case. Such value was obtained by calculating the amount of capital investment which would return the same net present value as in the base case. This procedure set a higher limit for the capital investments associated with a concept in order to reach economic competitiveness. If a concept could be developed with a CAPEX lower than the relative CAPEX_{max}, that concept would have a better economic performance compared to the base case (NPV > NPV_{concept_0a}). Conversely, if the CAPEX overpassed the CAPEX_{max} threshold, the concept would have a worse economic performance compared to the base case (NPV < NPV_{concept_0a}). Table 1 shows the major equipment which would approximately constitute the CAPEX for a specific concept. In the calculations, it was assumed that all the investments were made in 2017, which is the starting point of the economic analysis.

Table 1: Major equipment which would constitute the CAPEX of the various concepts.

	Major equipment		Major equipment
Concept 0a	3 X LM2500+G4 6 X LM6000 PF 4 X WHRU	Concept 1	Gas-fired/electric heaters HVDC cables AC cables Transformer station Converter station
Concept 0b	3 X LM2500+G4 5 X LM6000 PF 4 X WHRU AC cables Transformer station	Concept 2	1 X LM2500+G4 2 X LM6000 PF 3 X WHRU HVDC cables AC cables Transformer station Converter station

2.6 Scenarios for the analysis of the results

Three different future scenarios were evaluated, based on the World Energy Outlook by IEA (2016a):

- Current policies scenario
- New policies scenario
- 450 scenario

Input information for gas and CO₂ price estimations (see Figure 3a) were taken from (IEA, 2016a). The petroleum sector in Norway is both subjected to a CO₂ tax of 1.02 NOK (0.12 \$) per standard cubic meter of gas (value for 2016) and, since 2008, to the EU Emissions Trading System (EU ETS). The policy of the Norwegian government with regard to the petroleum industry seems to involve adjustments of the CO₂ tax level in order to compensate for increased cost due to the ETS, so to maintain the total CO₂ price approximately constant. This effect was accounted for in the definition of the CO₂ price estimations. The spot price in the electrification area was given by the power system model. Figure 3b shows how such power price decreases throughout the years. A driver for this decrease is the expansion of the fuel-cost-free wind and solar power. The results are in line with the Nordic IEA analysis (IEA, 2016b), which expects a power price between 40 and 60 \$/MWh in Norway. To obtain the actual price for the customer, two more terms should be considered to make the total power price, namely the grid tariff and the electricity fee. The grid tariff can be positive or negative depending on the export/import situation. Given the geographical location of Utsira area, with excess hydro power, the grid tariff would likely be negative most of the time, as the power consumption would lead to lower losses and relieve the grid. With regard to the electricity fee, industrial consumers get a reduced fee. It was assumed that these two terms balance out and, thus, the power spot price was used for further analyses.

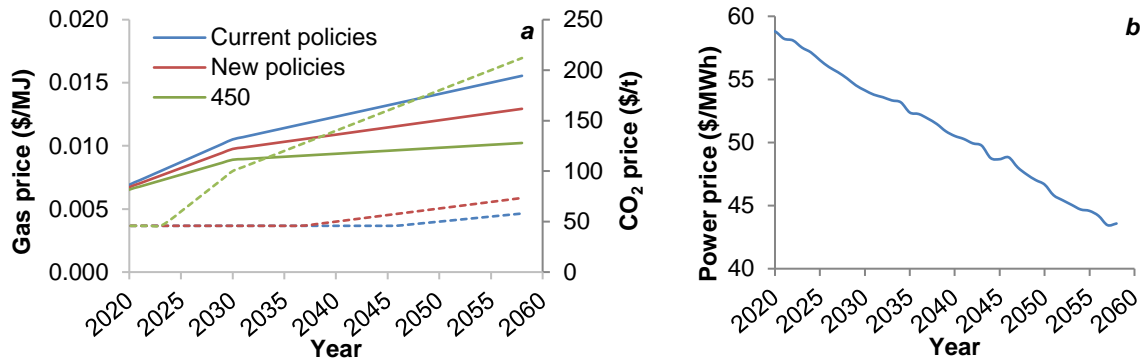


Figure 3: Gas (solid lines) and CO₂ (dotted lines) price estimations (3a) according to the scenarios considered. Power prices (3b) given by the power system model.

3. Results and discussions

The results of the simulations are presented in this section. The environmental impact of offshore operations was assessed in terms of cumulative CO₂ emissions. The economic competitiveness was analysed, by taking into account future energy policies and their effect on the energy system. Table 2 summarizes the results obtained. Other aspects also have a significant influence on the feasibility of a concept, especially for offshore applications. For instance, safety is of major importance and a technical risk assessment should be included in a comprehensive evaluation. Such analysis was not implemented but could be an interesting development for further work.

Table 2: Environmental and economic outputs of the lifetime simulations of the different concepts.

	CAPEX _{max} (M\$)			CO ₂ emissions (Mt)
	Current policies	New policies	450	
Concept 0a	214*	214*	214*	31
Concept 0b	290	286	295	30
Concept 1	1,096	983	1,274	14
Concept 2	963	870	1,116	16

* these values are not CAPEX_{max} but the actual estimation of the CAPEX for Concept 0a

3.1 CO₂ emissions throughout lifetime

The cumulative CO₂ emissions associated with the different concepts conveyed a clear message. The electrification of the Utsira area would result in a substantial cut of CO₂ emissions. The Concept 1 entailed a reduction of CO₂ emissions of 56 % compared to Concept 0a, which can be considered the common practice for offshore installations. Concept 2, a hybrid between local power generation and PFS, returned a 48 % CO₂ emissions reduction. If electrification was not a viable option, the power integration of the area (Concept 0b) resulted in a CO₂ emissions reduction of 3 %. Figure 4 shows the annual CO₂ emissions which summed up give the cumulative CO₂ emissions. The concepts involving PFS resulted in diminished emissions in almost every year of the plants' lifetime.

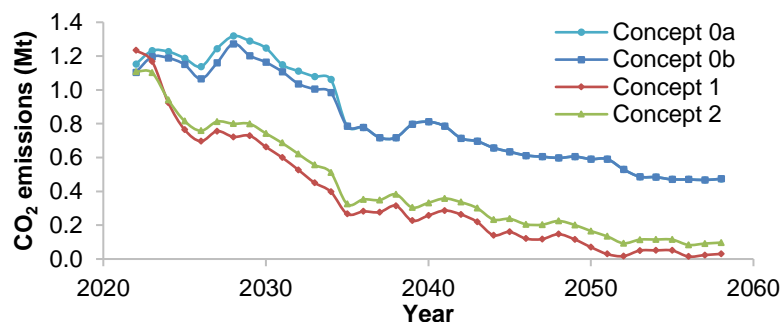


Figure 4: Annual CO₂ emissions of the different concepts.

3.2 Economic performance of the various concepts

The analysis outputs (Table 2) showed that full electrification (Concept 1) would display a better economic performance compared to the base case with a CAPEX lower than 1,096 M\$ within the current policies scenario. This margin decreases to 983 M\$ within the new policies scenario, while it reaches 1,310 M\$ within the 450 scenario. An estimation on the capital investment necessary to electrify the Utsira formation was found in the literature (Statoil, 2014) and was equal to $12,500 \pm 3,750$ MNOK (approximately $1,500 \pm 450$ M\$). There is a significant gap between actual investment cost and the maximum spendable cost. The hybrid solution (Concept 2) displays a lower margin to reach economic competitiveness while it would most probably require an investment at least equal to Concept 1. The power integration of the area (Concept 0b) would have a lower relative economic cost compared to the base case (Concept 0a), if it could be implemented with a total investment ranging between 286 and 295 M\$ according to the different scenarios.

4. Conclusions

The effectiveness of different concepts for supplying energy to a large offshore oil and gas area in the North Sea was investigated. The concepts considered included onsite power generation by means of simple GT cycles with or without power integration of the offshore area (respectively, Concept 0a and 0b), full electrification of the area (Concept 1) and a hybrid solution where power can be either generated onsite or taken from the onshore grid (Concept 2). An integrated approach was used for the analysis, consisting of the modelling of the power generation processes and of the power system affected by the offshore electrification. This novel analysis framework provides a more complete set of information to evaluate the overall effectiveness of a concept and, as such, aims to give an original contribution to the literature on the topic. The period from year 2022 to 2058 was considered for the analyses. Estimations of the environmental and economic effects throughout the years were based on three different future scenarios. The following conclusions could be made:

- Whilst the electrification of the offshore area resulted in a 56 % cut of CO₂ emissions compared to the base case with onsite power generation, its economic competitiveness is disputable and would need strong support in terms of energy policies.
- The hybrid solution returned a smaller, albeit significant, CO₂ emissions reduction (48 %), while displaying a lower margin to reach economic competitiveness in comparison to full electrification.
- The concept involving onsite power generation and power integration between the facilities returned a 3 % decrease in the cumulative CO₂ emissions and it would reach economic competitiveness only with a limited additional investment compared to the base case.

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