A/S Norske Shell E&P

MID-NORWAY POWER STUDY

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1 Summary

This report documents the results of a four months study by Shell in relation to the request from the Petroleum and Energy Minister to evaluate the viability of developing a gas fired power plant in the Nyhamna area. The power plant sizes studied are 50, 200, 430 and 860 MW nominal output, both with and without a Carbon Capture and Storage (CCS) facilities and with an earliest start up of 2014.

The power supply and demand balance is evaluated to investigate the case for building a power plant depending on demand development in the mid-Norway region. The report concludes that there is a deficit in the region which will probably be addressed through a combination of planned measures, including the planned 400 MW capacity transmission line (Ørskog to Fardal) and temporary power plants at Tjebegodden and Nyhamna together with an assumed new 2 TWh/yr capacity small hydro and wind power projects. However, a commercial sized power plant (400 MW or larger) could provide a more robust means of supply as well as provide the potential for further demand growth.

The study has evaluated technical and commercial concepts for the different sized power plants with considerable experience drawn from Shell's earlier involvement in the Halten CO_2 project. Order of magnitude cost estimates have been developed based on the current market outlook, for the power plant cases and the associated carbon capture facilities, including CO_2 transportation pipeline and disposal wells. The carbon capture design has been based on state of the art amine technology. An economic model was developed specifically for this study for a power plant using a range of assumptions for gas, electricity and carbon credit prices. The model includes optimisation of income based on positive “sparkspread”. The conclusion from the evaluations shows that there is a substantial gap between the likely economics and the economics that would be required for a commercial company to make an investment in a power plant investment. The main reasons for this are the investment cost and expected prices both for gas and electricity.

Further work was performed to explore the potential benefits to Ormen Lange of reduced supply interruptions and lower electricity prices in the region that may be realised if a power station were built. This concluded that, even when using optimistic assumptions of the additional benefits, the investment is not viable.

The cost of CCS facilities is significant and the potential revenue stream from the value of CO_2 stored is too low to make any commercial investment in CCS interesting. The potential requirement for CO_2 handling creates an additional uncertainty for a potential power plant investor and further impacts on the already negative business case.

2 Introduction

2.1 Background

In January 2008, the Minister of Petroleum and Energy asked Shell, as the operator of Ormen Lange, to assess whether there is potential for developing a viable gas-fired power station in the Nyhamna area.

Through a dialogue with the MPE, the Minister’s request has been further defined and the scope of work clarified.

Shell has performed study work to support this evaluation with the target of exploring the possibilities for a gas-fired power station in the Nyhamna area by mid-year 2008.

3 Regional background

3.1 Introduction

The mid-Norway region has a shortfall in generation capacity due to increasing demand at a time when no significant new power generation projects have been built in the last 10 years. Locally generated hydroelectric power accounts for about 50% of total supply with the balance imported from outside the region.

In a normal rainfall year there is sufficient power to supply the area, in a dry year hydro-electric production falls resulting in an increased requirement from imports. With increased demand there is the risk of insufficient capacity in the grid to import the required power.

The grid operator, Statnett, has responded to this challenge by both strengthening the Nea-Jarpstrømmen connection (complete end 2009) and investing in equipment to stabilise the grid at times of high import. Statnett is also building two temporary gas fired power stations (‘Reserve PP’), which will be completed in 2008/09. In principle these will secure power supplies in dry years until a more permanent solution can be found. The Reserve PP’s are inefficient and will have significant CO_2 emissions in operation. This has led to very strong restrictions being placed on their use.

This chapter contains an evaluation of the power supply and demand balance in the mid-Norway price area (NO2) and the potential effects of an imbalance on the region. The severity of a power shortfall and possible solutions are also examined.

The analysis is based on data from a number of sources – including Shell and StatoilHydro’s previous work on the Halten CO_2 Project in 2007, publicly available data from NVE, Statnett and local grid companies. ECON has also been used to prepare the supply and demand profiles and Markedskraft have supplied historical precipitation data and price forecasts.

3.2 Near term situation

Despite very wet years in 2005 and 2007, the supply-demand balance for mid-Norway is not assured. Table 3.1 shows the forecast balance for 2010; a dry year would result in a substantial power shortage in the mid-Norway price area unless optimistic assumptions regarding grid import capacity are made.

This picture was the driver for Statnett to introduce special measures into the mid-Norway area to manage such as situation (SAKS measures):

a) New price area NO2 – to more accurately reflect supply constraints, and cut price sensitive demand,

b) SAKS

- Energy Options – where Statnett can pay some large consumers to cut load at critical points,
- Reserve power stations – two 150MW gas fired power stations, located at Nyhamna and Tjeldbergodden.

Supply	GWh	Demand	GWh
Hydro - normal year	12791	Industry	11178 [1)]
Hydro - dry year	10066	Domestic	10449
Wind (norm / dry)	896/672 [3)]	Losses	815
Comb. Heat & Power	160		
Total (normal yr)	**13847**		**22442**
Total (dry yr)	**10898**		

Import required (normal yr)	**8595 GWh**
Import required (dry yr)	**11544 GWh**

Available import capacity (2010)	Load factor	import capacity [2)] GWh	Dry year deficit GWh
	60%	8242	3302
1600 MW	70%	9615	1929
	80%	10989	555

Table 3.1 Supply-Demand (estimated 2010)

Notes
1) Consumption figures for industry in 2010 are based on a domestic consumption growth rate of 0,5%.
2) Available import – this is shown at three levels, which represent the average utilisation of the power grid connecting NO2 to NO1 and Sweden on a yearly basis. Statnett have in the past indicated that a load factor higher than 70% is technically challenging, as it requires producers and the grid to co-ordinate action to maximise import capacity. This is in conflict with the individual producer's ambition to maximise its own profit and hence is difficult to achieve.
3) Wind – dry year production is assumed to have a lower load factor (30%) than normal year (40%), due to correspondence of dry and still weather patterns.

The total effect of measures a) and b) on the previous page is thought to be fairly limited as demand has limited price elasticity, perhaps leading to only a 0.5TWh reduction. The Reserve PP's would be able to bridge a gap of circa 2-3TWh/yr. The market price in this scenario is likely to be significantly higher in the mid-Norway price area than in the rest of Nordpool, though it is not clear how power from the reserve power stations will be sold in the market.

3.3 Scenarios for the future

It is uncertain how the supply and demand balance in mid-Norway will develop. It should be noted, that these scenarios are generated by Shell and represents only one view among many. Shell is not an electricity power company and lack experience within this field and has therefore used available data to be able to evaluate concrete cases. The main contributing factors are:

- Potential delays in Statnett's 420kV import power line Ørskog-Fardal. Planned to be complete in December 2012, it is controversial and subject to opposition.
- Difficulties in realising commercially viable power generation projects due to rising capital costs, fuel costs and the current regulatory framework (particularly wind and gas fired power stations).
- Future domestic demand expectations – although lower demand in the last 5 years, it may rise again due to consumers switching from oil products for heating.
- Future industrial demand expectations – excluding the increased demand from Ormen Lange and Sundalsøra Alu smelter, there are other industries that would probably consider investment in new capacity if there were better certainty regarding future power availability at "affordable prices". The offshore industry may also request access to power from onshore sources for future developments.

Figure 3.1 below illustrates a number of different possibilities of demand and supply scenarios.

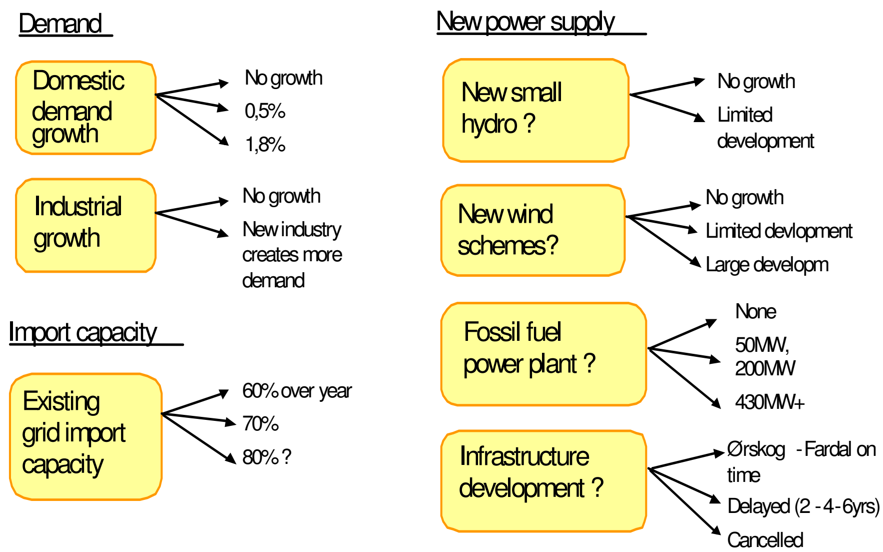


Figure 3.1 Supply-demand-import - many degrees of freedom

3.3.1 Demand scenarios

Power demand in mid-Norway has risen sharply in the last ten years due to increases in heavy industry consumption. The scenarios in Table 3.2 below assume that industrial demand will now stabilise and future growth will come from the domestic and light industry sectors. It can be argued that a more secure supply situation would create opportunities for investment and therefore result in increased demand from the large industrial sector. We have excluded this impact from our scenarios.

a) Flat demand	- No further demand growth other than that planned by Ormen Lange terminal
b) Demand growth 0.5%/yr	- Growth applied only to domestic consumption. (This is the recent historical growth rate)
c) Demand growth 1.8%/yr	- Growth to match historic national average when power was in surplus (80's and 90's)

Table 3.2 Demand scenarios used in this study

Note; demand growth in cases b) and c) will be applied to all demand with exception of identified large industry consumers within the price area (Sundalsøra ASU, Ormen Lange, Elkem).

3.3.2 Supply scenarios

The supply side is particularly difficult to predict as potential wind and fossil fuel fired power projects are experiencing large cost increases driven by the global market for these industries. The alternative to new regional power generation is to strengthen the grid to import more power from Sweden and southern Norway, areas more often in surplus (though this is not necessarily the case in dry years). The supply scenarios selected are summarised in Table 3.3 below.

1) Reference scenario	- No further action – this case is intended to record the supply situation today and act as a reference for alternatives. No new supply projects post 2008 - The Swedish line connection Nea-Jarpstrømmen is completed as construction is underway.
2) 'As planned' scenario	- Ørskog-Fardal 2012, + other infrastructure projects delivered on time - New renewable generation comes as forecast - New (small) hydro + wind deliver +1.2 TWh in 2012, 2.3TWh in 2020 (wind 0.5TWh out of total)
3) 'Delays' scenario (lower activity)	- Southern Line delayed til 2016 (Ørskog – Fardal) - Swedish line completed on time (Jarpstrømmen – Nea) - Limited new renewables generation, - 0,5TWh wind and 0,5TWh hydro from 2008-2020
4) 'More renewables' scenario	- As for 'Delays', but new increased renewable power generation capacity 2008-2020 - Wind 2 TWh/yr developed - Hydro +1,9TWh

Table 3.3 Supply scenarios used in the study

3.4 Evaluation

A simple spreadsheet model has been developed to evaluate the cases described above to determine the balance between supply and demand. The model calculates the balance based on different import infrastructure load factors and also allows gas fired power station cases to be added.

3.4.1 Treatment of import capacity

As discussed under section 3.2, the exact volume of power that can be imported is uncertain. The capacity level is dependant on the availability of power in the surrounding regions and the ability of the grid operator to maintain stability of the grid when working at close to maximum capacity. In earlier publications, Statnett has indicated that an average usage of power import capacity much over 70% may not be possible. (Ref. 3.1). In this evaluation, three levels of average yearly loading are tested; 60, 70 and 80%.

3.4.2 Treatment of SAKS / emergency power supply measures

The use of Statnett's SAKS measures and operation of the reserve power stations at Nyhamna and Tjeldbergodden are not included in the analysis as these are essentially emergency measures which will only be triggered when there is a 50% chance or more of power rationing. The effect of SAKS/Energy options has been reported to be approximately 0.15TWh for mid-Norway so is relatively small in scope (Ref. 3.2).

The Reserve PP's can produce 2-3TWh in a year in response to a deficit situation.

3.4.3 Treatment of wind generation in dry years

All supply scenarios (except the reference case) include increased wind generation as part of the supply portfolio. In a normal year it has been assumed that these will produce at an average of 40% of their capacity over a year. This may be considered to be optimistic (current Norway average is 30-35%), but we believe this reflects the potential of mid-Norway's good wind resources. In a dry year load factor is reduced to 30% to account for poorer expected wind conditions associated with stable high pressures and dry weather. Due to the lack of available data the dry year figure is however not well substantiated.

Additional hydro capacity will also be required to compensate for intermittent generation – this is not accounted for in the analysis.

3.5 Results

A number of scenarios have been looked at in line with the descriptions above. The key conclusions can be divided into normal and dry years. The first part of Table 3.4 below shows a simplified set of results, drawing broad conclusions. The second and third parts describe with some more detail power supply robustness for Normal and Dry years. Further detailed year-by-year results tables can be found in Appendix A.

Supply scenario	Normal years	Dry years	Balancing power station case 1)
1. Reference case (no new projects)	70%+ load factor required on power grid to satisfy demand.	Reserve PP's just sufficient if import load factor is 70% or greater.	860MW if no new renewables developed by 2015
2. As planned	Tight until 2012, then ok. Improvement significant hydro increase	Post Ø-F, reserve power stations may not be required if 70%+import levels can be maintained	200 MW, 430MW if high growth scenario is assumed or less hydro is assumed
3. Delays	Low reserve margins out to 2016, 70%+ import required	Critical pre-Ø-F (2016), Post Ø-F, reserve power stations still likely required	430MW, though 200MW may be sufficient
4. More renewables	Low, but improving margins out to 2016. (Wind takes time to develop).	Deficit to 2016 (Ø-F), grid will require further investments due to large wind exposure.	200 MW+ power plant

Note: 1) power station size to reduce import load factor to <60% in all cases

Normal years (all demand growth scenarios)

1. Reference case (no new projects)	- In this scenario, the system balance worsens as demand increases. This produces a deficit in normal years if the power net cannot operate with a load factor greater than 60%. The Reserve PP's may have to run in drier years (not just the extreme events).
2. As planned	- The system is able to meet demand in all cases, though this may require heavy usage of the grid before the Ørskog-Fardal power line is completed in 2012 requiring a load factor of >60%. This case also has a large amount of new-hydro 1,7TWh by 2020.
3. Delays	- As for (2), the system can meet demands, though the low margin period is now longer. A load factor >60% is required, at least 70% in a higher growth scenario.
4.More renewables	- The scenario assumes 2TWh renewable generation (wind) coming in over a 10 year period from 2010.. - This leads to a slowly improving balance, though import +/- 60% of capacity in normal years is required until the Ørskog - Fardal line is complete in 2016.

Dry years (all growth scenarios)

1.Reference case (no new projects)	- Reserve power stations and import line load factor >70% required. Without significant 2TWh/yr growth in either hydro or wind, reserve power stations may not be sufficient in a dry year.
2. As planned	- The system is unlikely to be able to meet demand without SAKS demand reductions and the reserve power stations running. - After the Ørskog - Fardal line is completed, the grid should be able to import sufficient power to satisfy demand though import grid utilisation will continue to be very high beyond 2012. Reserve power stations are probably no longer required. - A deficit may appear after 2020 if demand growth is high
3. Delays	- Even post completion of Ørskog - Fardal, reserve power generation will be required in the area unless very high import levels can be maintained. - In dry years before Ørskog - Fardal (2016), with 60% import load factor, both reserve power stations will run for the whole year.
4.More renewables	- Improving supply situation, may be possible to remove reserve power stations, though high requirement for import remains in dry years.

Table 3.4 Supply – demand balance evaluation (for all demand scenarios)

3.6 Overall conclusions from evaluation

3.6.1 Near term situation

There is a tight supply situation in mid-Norway until at least 2012, the earliest date of the Ørskog - Fardal power line / grid strengthening. If the power line is delayed, this situation will continue. In normal years, there is a margin of 0-1TWh in excess of requirements.

Reserve power stations

In a dry year scenario (-3TWh hydro electric available) the small surplus becomes a deficit, and the Reserve PP's would probably need to run for a significant part of the year to make up for lower hydro-electric (and wind) power supply. The point at which the Reserve PP's will be required is uncertain as it depends on the effect of high market prices and Statnett's SAKS measures in curbing demand. If it is assumed that SAKS reduce demand by 0,5TWh/yr, then a deficit situation will not occur until hydro-electric production drops by at least 1.5-2TWh. This corresponds approximately to a P80 event - 20% of the last 40 years have been sufficiently dry to create such a deficit.

3.6.2 Longer term outlook

The construction of the Ørskog - Fardal transmission line would significantly improve the power balance in dry years. The power line alone will not be sufficient – other power sources should also be developed. Taking the 2008 reference scenario (which includes no further projects post 2008), the gap between available supply and demand could reach 4-5 TWh in a dry year. To bridge this, an additional 2-3 TWh/yr is required on top of 2 TWh from the new power line. Additional power could come from a gas-fired power station, wind parks or new hydro-electric schemes. Some of the incremental power required will be supplied by wind and hydro projects already planned, but the balance will be new developments. Table 3.5 below shows options for supply sources and cases that would deliver sufficient capacity.

Potential dry year deficit 5000 GWh/yr

	Capacity (MW)	Technical Availability	Load factor	Effective Hrs	Supply GWh/yr
Import cable 400MW @ 60%	400	98 %	60 %	5151	2060
Gas PP (baseload)	860	95 %	75 %	6242	5368
Gas PP (baseload)	430	95 %	100 %	8322	3578
Gas PP (baseload)	200	95 %	100 %	8322	1664
Onshore wind	600	95 %	40 %	3329	1997
Small hydro-electric	500	98 %	50 %	4292	2146

Combinations to cover deficit (MW installed capacity)	Power line	Gas PP	Onshore wind	Small hydro	Coverage (GWh/yr)
Case 1	400	0	625	200	5000
Case 2	400	250	200	50	5000
Case 3	400	430	0	0	5600
Case 4	0	430	300	100	5000
Case 5	0	0	750	600	5100

Table 3.5 Possible supply cases for mid-Norway

There are some questions surrounding large wind developments as the only new regional generation source for the following reasons:

- Dry years often reduce wind energy production, lowering the total volume of power produced (perhaps only 30% effective instead of 40%).
- Large wind generation is challenging for the grid operator to manage, as it is variable / intermittent and the grid will require additional back-up capacity.
- A combination of wind and hydro-electric power developments is attractive as hydro can react very rapidly to variations in production, however, the regulatory framework today contains no measures to achieve such co-ordination. It is also commercially difficult to achieve when the wind and hydro have different owners.

In a dry year where the grid is importing close to maximum, a fall out of significant wind generation could cause difficulties. To address this issue, we believe that the most suitable solution would be 1) develop more grid capacity, either in the form of a large capacity reserve on hydro-electric stations, or 2) installing more base load power generation so there is spare capacity in the grid import lines.

3.6.3 Pricing

The historical price difference (2007/08) between the Nordpool system and NO2 area is approx +1.5øre /KWh, however, this period was extremely wet. In normal years and as the balance tightens over the next five years the price differential is likely to increase. Today's price differential represents 300MNOK/yr additional cost for power consumers.

In a dry year, the average difference to the Nordpool system price is likely to be a lot higher. Figures of +10 øre/kWh (100 NOK/MWh) over the whole year are not unlikely, with peak prices being much higher. We have not performed any analysis to quantify this further.

3.7 Implications on power supply to Ormen Lange

3.7.1 Ormen Lange unit Position

This study has been conducted by Shell and represents the views of Shell, the Ormen Lange Operator. The following points give the Ormen Lange unit's formal view on power supply in the mid-Norway area.

1. Nyhamna purchases electricity directly from the grid, and as for any user of the grid, the availability of electricity is a state responsibility, as stated in the PDO.
2. Statnett has plans to strengthen the electricity supply to the area; the Ormen Lange Unit wishes to see such actions taken quickly

3. The source of power for field pre-compression will be evaluated at a later stage as part of the phase II project.

The Economics section 6.2 includes an evaluation of the economic business case for Ormen Lange developing a power plant for its own needs in order to address any concerns for security of supply and high electricity prices.

3.7.2 Security of supply

Study work performed for the OL unit by SINTEF (TRF 6426, AN 06.12.104, AN 08.12.54) has shown that the Nyhamna terminal is not particularly vulnerable to supply interruptions, even during dry years. SINTEF indicate a supply failure rate of approximately 1 to 2 per years.

In many cases such a supply interruption would be very short and may not trigger a shutdown of the plant. If the interruption is significant enough to cause a plant shutdown, it is not certain that there would be an economic loss because line-pack in the Langeled gas pipeline could be used to help Gassco manage deliveries in the period up to the field restarting production.

4 Evaluation basis

4.1 Introduction to the economic evaluation

Four sizes of gas fired power stations were defined that were used to understand the commercial viability of such a power station at Nyhamna, namely the following nominal sizes; 50, 200, 430 and 860MW.

This chapter describes the commercial and market assumptions used in a conventional company economics model to develop a view on the commerciality of the various power station sizes both with and without CO_2 capture plants. The commercial parameters used are generally based on public domain data and reports, sometimes supplemented with more detailed study work performed. Technical project costs, process performance parameters for the different power station sizes and the associated CO_2 capture plants are described in more details in Chapter 5. Given the number of variables a set of cases has been developed, which provides a plausible view of the future, see Table 4.1. The base case for each parameter is given in bold.

Gas price	Power price	Reservoir sensitivity	LT Power price	CO_2 costs	CO_2 allocation	CAPEX	OPEX	Discount rates
Low	Low	Wetter	Flat	Low	**Base**	**Base**	**Base**	0%
Base	**Base**	**P50**	**Coal linked**	**Mid**	Zero	--20%	Not run	5%
High	High	Drier		High		+40%	Not run	7%
								10%,15%

Table 4.1 Case map - Input variables for economic analysis

4.2 Gas (fuel to power plant)

The basis for our gas price assumptions is public domain forecasts provided by Global Insight, Wood-Mackenzie and UK "NBP" traded future prices:

Low case comes from Wood-Mackenzie and is based on $55/bbl

Base case comes from Global Insight

High case corresponds with UK NBP futures.

	LOW	BASE	HIGH
€/MWh GHV	13	20	26
NOK/Sm3 (40MJ gas)	1,11	1,72	2,23

Table 4.2 Gas pricing assumptions

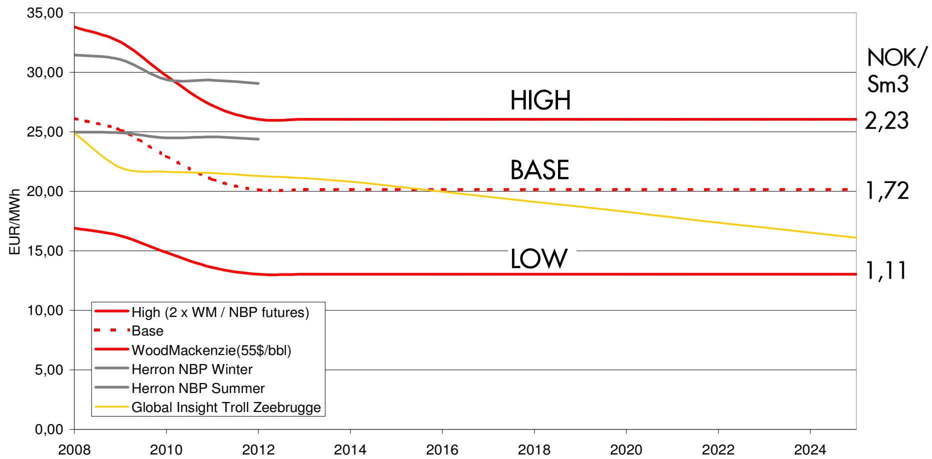


Figure 4.1 Gas pricing assumptions

The low price scenario would probably require a significant fall in energy commodities including oil in order to be realised. There is also a case to consider a scenario with higher gas prices than indicated in the high case driven by tightening supply-demand balance in North West Europe.

In addition to the "flat" gas prices used, a seasonal gas price profile has been generated from historical market data for the UK NBP. This profile is applied to the annual average prices to enable more detailed analyses to estimate the seasonal load factors for the power plant. The three gas price profiles are shown in Figure 4.1.

4.3 Nordpool power assumptions

The basis for these assumptions is a detailed study carried out by power market consultants, Markedskraft for the period 2011-2016. Beyond 2016 two approaches have been taken for power pricing:

a) Flat real terms pricing or,

b) Long Run Marginal Costs for German coal power generation which assumes that coal + full CO_2 costs will continue to be the marginal producer into the Nordpool market.

The flat case post 2016 is consistent with the flat gas pricing model in 4.2, however, the LT coal costs model may be closer to reality as it is expected that costs for CO_2 emissions will rise quickly beyond 2013. The LT coal price model was used for evaluating the economics of the power plant.

Three electricity price scenarios will be used for economic evaluations in this study. The prices quoted are System prices and not linked directly to the mid-Norway price area. These are shown in Table 4.3 and in Figure 4.2.

	Long Term Coal Generation driven				Flat price alternative		
Year	Low	Base	High		Low	Base	High
2011	37,5	47,2	60,7		37,5	47,2	60,7
2012	37,5	48,9	60,4		37,5	48,9	60,4
2013	37,5	49,0	60,0		37,5	49,0	60,0
2014	37,5	49,0	60,3		37,5	49,0	60,3
2015	37,5	49,6	60,5		37,5	49,6	60,5
2016	37,5	50,0	60,2		37,5	50,0	60,2
2017	38,8	50,7	60,7		37,5	50,0	60,0
2018	40,1	51,4	61,1		37,5	50,0	60,0
2019	41,3	52,1	61,6		37,5	50,0	60,0
2020	41,8	53,0	63,5		37,5	50,0	60,0
2021	42,2	54,5	65,5		37,5	50,0	60,0
2022	42,6	55,4	67,6		37,5	50,0	60,0
2023	43,0	56,4	69,7		37,5	50,0	60,0
2024	43,4	57,3	71,9		37,5	50,0	60,0
2025	43,8	58,2	74,2		37,5	50,0	60,0
2026	43,7	58,0	74,7		37,5	50,0	60,0
2027	43,8	58,1	75,2		37,5	50,0	60,0
2028	43,8	58,1	75,2		37,5	50,0	60,0
2029	43,8	58,1	75,2		37,5	50,0	60,0
2030	43,8	58,1	75,2		37,5	50,0	60,0
2031	43,8	58,1	75,2		37,5	50,0	60,0
2032	43,8	58,1	75,2		37,5	50,0	60,0
2033	43,8	58,1	75,2		37,5	50,0	60,0
2034	43,8	58,1	75,2		37,5	50,0	60,0

Table 4.3 Nordpool system pricing assumptions 2011-2030, P50 reservoir filling

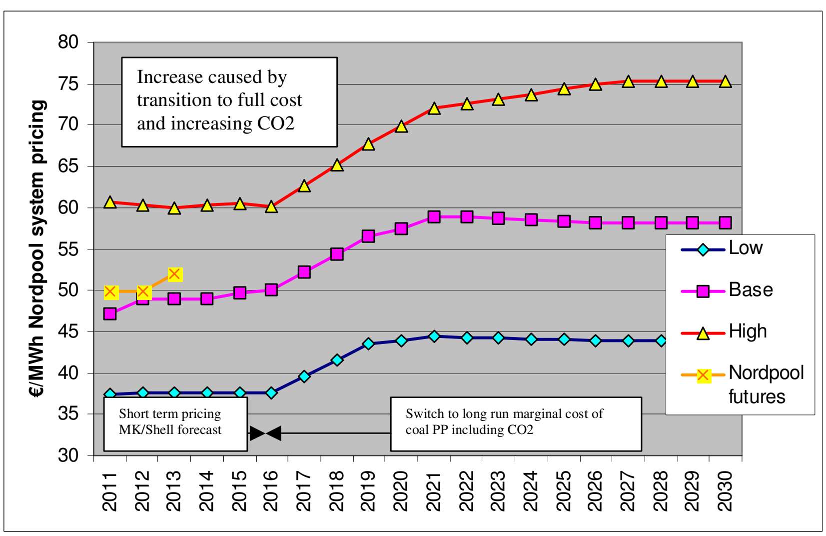


Figure 4.2. Nordpool system price assumptions– base load (LT coal price model)

4.3.1 Uncertainties in power price

Similar to the gas price analysis, there is a large degree of uncertainty in the proposed electricity price assumptions. The key variables driving price levels, weather, fuel costs, CO_2 costs, and the supply – demand balance, cannot be predicted with any accuracy. This is particularly the case beyond 2015, when Nordpool is expected to follow energy costs in Europe upwards due to rising CO_2 costs.

4.3.2 Seasonal variation

There is a strong seasonal variation in the Nordpool market as hydro-electric is the main generation form. Seasonal profiles have been established from the data provided by Markedskraft. These profiles cover normal reservoir filling (P50) cases, and dry (P80) and wet years (P20) for the different fuel prices (base-high-low). See Figure 1 in Appendix B for more details.

The seasonal variation is primarily modelled to determine the number of operating hours per year where a positive spark-spread can be expected. The variation in reservoir filling is also used to simulate the effect of wetter and drier than P50 weather patterns by combining more or less wet or dry years into a sequence of normal or P50 years.

4.3.3 Mid-Norway Price area differential

Since the NO2 price area was established in 2007, there has been a price differential of 2.0 øre/KWh between the Nordpool System and the mid-Norway price area 2. Until infrastructure/generation investments are completed this is expected to continue. In dry years when the supply-demand balance is weaker, there will be significantly larger differentials.

This differential is not accounted for in the price forecasts used in this modelling since it is expected that a gas fired power station (430MW, 860MW cases) would contribute to reducing the supply deficit and therefore eliminate the differential. This would have a socio-economic benefit (lower power prices) but not necessarily for the new producer.

4.4 CO_2 Pricing

Assumptions for CO_2 cost and quota distribution have been developed specifically for this study and are used in two ways during the analysis; firstly as an input assumption to power price modelling, and secondly as a direct cost to the gas-fired power plant and income to a CO_2 capture plant.

Three cases are used for CO_2 pricing, and two cases for quota allocation (to the power plant) as shown in Table 4.4 below. See Figure 2 in Appendix B for yearly profiles for these variables.

CO_2 pricing	
Low	CO_2 markets not working or over supplied with quota, flat prices €14/T
Base	Slow increase to €30/T by 2020 then flat
High	Slow increase to €50/T by 2027.

CO_2 quota	
Base	CO_2 free allocation dropping to zero by 2020
Zero	CO_2 free allocation dropping to zero in 2013

Table 4.4 CO_2 price and allocation assumptions

Conventional economic parameters used in the study are listed in Table 4.5 below.

Parameter	Value	Source / comment
Exchange rates		Markedskraft assumption
$/Euro	1,42	(October 07 rate)
NOK/Euro	7,69	(October 07 rate)
NOK/$	5,42	(October 07 rate)
Inflation	2%/yr	Markedskraft assumption
RT Discount factors	0, 5 , 7, 10, 15%	
Investment decision	1.7.2010	
Start up - power plant	01.01.2014	or according to project schedule
Start-up - CCS	01.04.2014	
Project operational duration (for economics)	20 years	This is probably shorter than typical technical design life, but is a realistic gas supply contract duration

Table 4.5. Conventional economic parameters

5 Technical and commercial concept

5.1 Overview of Scope

The engineering study work is based on four different power stations cases with capacities as shown in Table 5.1 below. As can be seen in the table, the cases have nominal capacities of 50,200, 430 and 860MW, but actual capacities are based on the specific technical solution selected (all gas turbines were selected from the Siemens range for simplicity).

Case 1 : 50MW *Actual installed 67.5MW* Small CCGT installation located on the Ormen Lange terminal site to provide power for the Phase II compression project. No export to the power grid is expected. CCS is not viable for this size of plant.	**Case 2 : 200MW** *Actual installed 253 MW* With CCS : export to grid 214 MW Small CCGT installation, sized to provide for peak consumption from the Ormen Lange field. During normal operations, the field facilities will use 120-180MW power, the rest could be exported to the grid.
Case 3 : 430 MW *Actual installed 417 MW* With CCS : export to grid 361 MW Small commercial scale power station operating towards the Nordpool market and industrial customers such as the Ormen Lange field.	**Case 4 : 860MW** *Actual installed 838 MW* With CCS : export to grid 720 MW Larger commercial scale power station operating towards the Nordpool market and industrial customers such as Ormen Lange

Table 5.1 Case descriptions

This section of the report gives a description of the technical aspects of the four cases presented above including cost and schedule data and some views on potential commercial models and location synergies.

5.2 Concept description

Figure 5.1 gives an overview of the scope for the mid-Norway power study at Nyhamna:

1. Overall site preparation & Civil Works including seawater cooling system, cost estimate and study work performed are by Norske Shell
2. Combined Cycle Gas Turbine (CCGT) Power Plant, cost estimates and conceptual studies performed by ESBI Engineering & Facilities Management and Shell Global Solutions
3. Carbon Capture Plant including CO_2 compression, cost estimate and conceptual studies performed by Mitsubishi Heavy Industries (MHI) and Shell Global Solutions
4. CO_2 pipeline and control line to injection location and storage wells, cost estimate and conceptual studies performed by Norske Shell

For illustration purpose, a 430MW power plant with carbon capture facilities has been incorporated in a picture of the Nyhamna land-site, see Appendix C1.

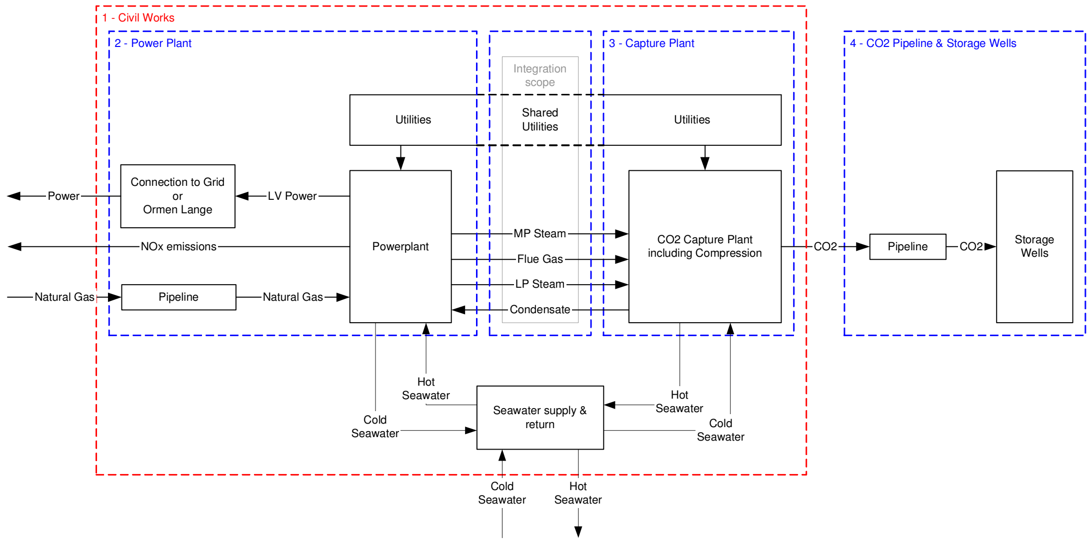


Figure 5.1 Overview of concepts

To ensure a level playing field and a fair comparison between each of the options, it has been assumed that there will be no integration optimization between the power plant and the capture plant, besides the usage of Low Pressure (LP) and Medium Pressure (MP) steam.

Key assumptions with regards to the concept:

- No duct firing is used in any of the cases
- No High Pressure (HP) steam extraction and integration is assumed
- The capturing plant will capture 87.5 % of the CO_2 emissions
- Both the capture and the power plant will utilize once through sea water cooling
- Compression of CO_2 to 270 barg is included

5.3 Power Plant

Each of the four concepts as described in 5.1 is based on a CCGT (Combined Cycle Gas Turbine) power plant. For each of the chosen four sizes a variety of major vendors offer gas turbines that fit these sizes. For each of the power plants the line-up will typically consist of the following:

1. Gas Turbine Package with Dry Low NO_x burners for reduced emissions
2. Heat Recovery and Steam Generation (HRSG)
3. Steam turbine package

For the largest 860 MW option, the plant will comprise of two Gas Turbine Packages and HRSG's and a single Steam Turbine. A simplified diagram of the power plant is given in Figure 5.2, indicating the Gas Turbine, the HRSG and the export of the Flue Gas and steam to the CO_2 capture facility.

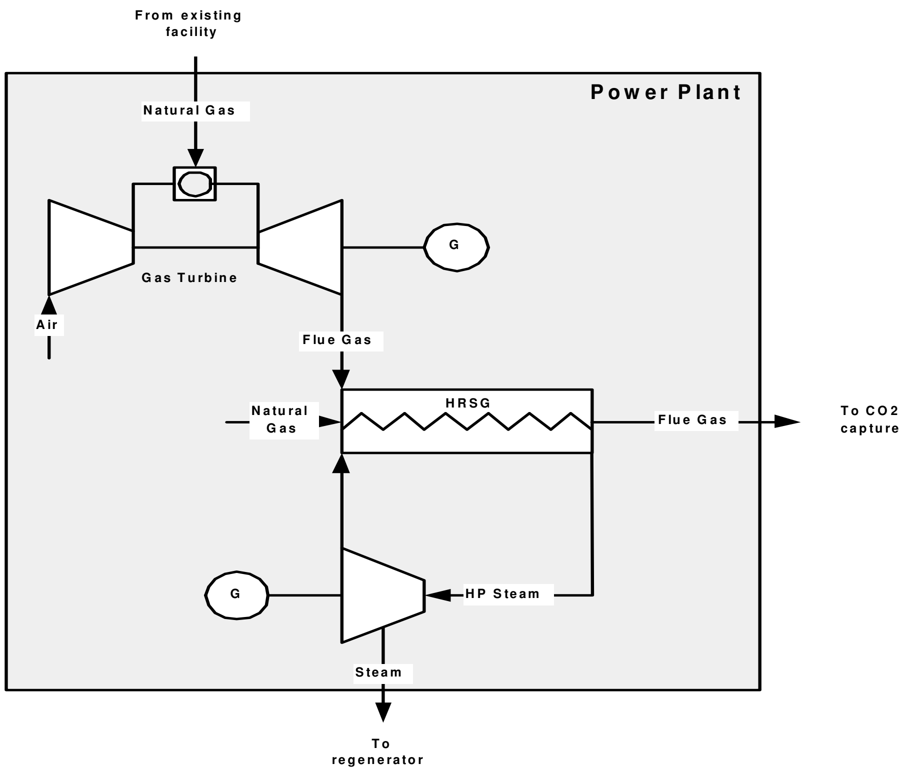


Figure 5.2 Power Plant Overview

The overall power plant concept remains the same for each of the four options. For each of the power plants a selection was made for a gas turbine to base the calculations on, this selection does not in any way indicate a preference for this specific machine or vendor. An overview is given in Table 5.2 of the main performance data, showing the performance of the power plant in standalone operation without a Carbon Capture Facility.

All numbers excluding Carbon Capture Plant (nominal size)	**Option 1** **50 MW**	**Option 2** **200 MW**	**Option 3** **430 MW**	**Option 4** **860 MW**
GT basis for studies (all Siemens)	1 x SGT800	1 x SGT5-2000E	1 x SGT5-4000F	2 x SGT5-4000F
Net power output to grid (MW)*	67,5	253	417	838
CO_2 from CCGT (kg/MWh net)*	380	384	355	353
LHV Net electrical efficiency*	53.1%	52.5%	56.7	57
NO_x Emissions from Power Plant (kg/h)*	19.8	74.9	114.7	229.4
** Values above calculated by ESBI, reference to ESBI report # P387100-R500-003 - Conceptual Study for Nyhamna CCGT Opportunity Project'*				

Table 5.2 Standalone CCGT Performance

5.4 Capture Plant

This study is based on post combusting carbon capture with application of the "state of the art" amine process.

As indicated in the assumptions, the efficiency of the carbon capture plant is an annual average of 87.5% CO_2 recovery. The capture technology used is an amine-based process that has been developed by MHI. For each of the four cases that have been described above, the capture plant is scaled to fit the CO_2 production of the power plant. The process line-up as described below fundamentally stays the same.

The simplified flow scheme of the capture plant shown in Figure 5.3 gives an overview of the main scope items that comprise the mid-Norway power study at Nyhamna

This diagram does not contain all the equipment; only the major items have been included to create a high level overview:

- *Flue gas quencher*, where the flue gas is cooled by spraying water
- *Flue gas blower*, to boost the pressure of the flue gas in order to overcome the pressure difference in the capturing process.
- *CO_2 absorber*, where the flue gas is contacted with lean solvent to extract the CO_2 from the flue gas.
- *Solvent regenerator*, where the rich solvent is stripped of CO_2 by heating with steam that is extracted from the power plant.
- *CO_2 compressor*, where the CO_2 is compressed up to a sufficiently high pressure for injection into wells.

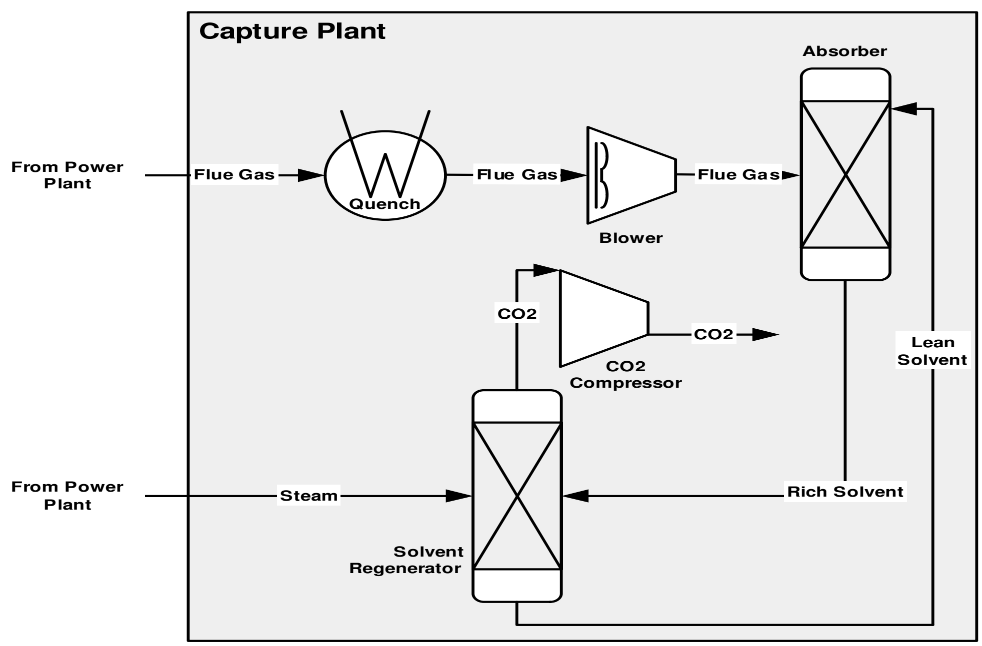


Figure 5.3 Capture Plant Overview

Table 5.3 gives an overview of the overall performance of the power plant and carbon capture plant for each of the four options.

All numbers including Carbon Capture Plant (nominal size)	**Option 1** **50 MW**	**Option 2** **200 MW**	**Option 3** **430 MW**	**Option 4** **860 MW**
GT basis for studies (all Siemens)	1 x SGT800	1 x SGT5-2000E	1 x SGT5-4000F	2 x SGT5-4000F
Overall performance				
Net Output (MW)	58	214	361	720
Net electrical efficiency (overall)	45.4 %	44.5 %	49.0 %	48.9 %
CO_2 from CCGT (kg/MWh net)	444	453	411	412
NO_x Emissions from Power Plant (kg/h)	19.8	74.9	114.7	229.4
CCP Power & Steam Consumption				
CCP Steam requirement (t/h)	35	130	219	437
CCP Power requirement (MWe)	4.5	16.8	27.9	55.8
** Values above calculated by ESBI, reference to ESBI report # P387100-R500-003 - 'Conceptual Study for Nyhamna CCGT Opportunity Project'*				

Table 5.3 CCGT with Capture Plant Performance

5.5 Implications of integration with CC

For the Halten CO_2 study integration between the power plant and the amine plant were studied and implemented in the design. However, the power plant and the capture plant can be built separately and independently. This may not be a preferred solution from the point of view of cost and synergy between the two plants. Capture plant will need the flue gas, power and steam from the power plant. Provisions or pre-investment must be made for a " CO_2 capture ready" power plant.

Without careful planning either equipment installed in the power plant could become redundant or additional equipment will be needed later to support the capture plant operations (for example adding steam boiler to generate steam for the amine regeneration).

5.6 Capture Technology

The MHI amine post-combustion process is considered state of art technology for CO_2 capture today. However, the process can be further optimized for CCS application. No major step change is foreseen for the post combustion CO_2 capture technology in the near future.

5.7 Pipeline and storage

5.7.1 Pipeline and Well Template

The length of the pipeline route from Nyhamna to a storage location has been assumed to be 150km in this study. This assumption covers a reasonable challenging routing out the fjord from the Nyhamna site to a potential storage location in the Halten area as no specific storage locations site has been selected. No detailed work has been conducted on the landfall. It is assumed that the spear landfall J-tube can be used or a new landfall approach can be made and this has been included in the cost estimates.

Different pipeline nominal diameters have been selected for the various power plant sizes as follows; 8" for the 50MW and 200 MW cases, 10" for the 430MW case and 14" for the 860MW case. The interface at Nyhamna is assumed to be at an anchor flange, which interfaces with the land pipeline from the CO_2 compression facilities. The interface at the well template is assumed to be a tie-in spool at the template.

The system design is based on the assumption that the CO_2 will be transported in liquid state without free water. CO_2 is assumed to enter the pipeline at Nyhamna at 270 bar. CO_2 transport capacity for the various pipeline sizes will be sufficient for the required CO_2 volumes produced.

Transport capacity for additional volumes not coming from the capture plant at Nyhamna has not been included and will, if required, be subject to new evaluations.

A subsea wellhead template configured with two wells is included assuming that two injection wells will give sufficient injection capacity. This assumption will need to be further challenged and optimized based on the actual location and formation structure selected and the volume to be injected.

The overall pipeline cost estimates includes an umbilical from land to the template. A schematic storage infrastructure is given in Figure 5.4.

Gassco are performing CO_2 Transport Network studies for the Mongstad and Kårstø projects to currently two identified potential storage sites in the North Sea. The Johansen formation next to the Troll field is one of the options for Mongstad. This location is in the order of 350 km from Nyhamna and has at the present not been considered a realistic candidate for storing CO_2 via a pipeline from Nyhamna. Further, Gassco is also conducting, on behalf of the HaltenNordland forum, evacuation studies of CO_2 rich gas discoveries from that area, including alternatives for handling the CO_2. With all this CO_2 transport and storage related activities ongoing, it is recognized that a CO_2 handling system at Nyhamna can not be seen in isolation and will need to be included in the total picture to find the best, overall, solution for future activities in the area requiring CO_2 handling.

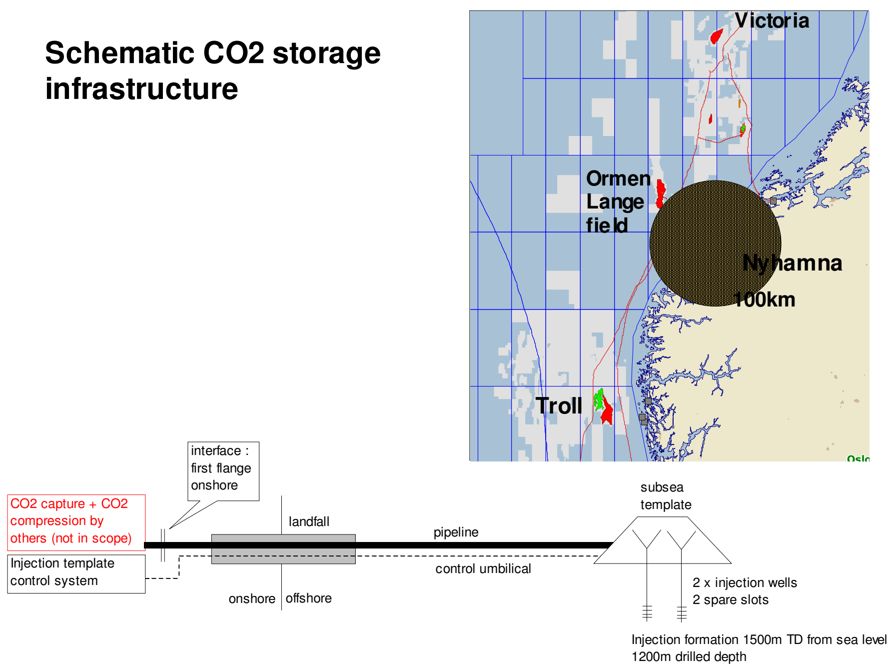


Figure 5.4 Schematic CO_2 pipeline infrastructure

5.7.2 CO_2 Storage Location

A high level screening study has been performed looking at potential storage locations in the Halten area. The work has focused around dry exploration wells in an area within a radius of 150 km from Nyhamna. A number of dry exploration wells have been drilled in the 80's and 90's, see Figure 5.5, where good reservoir quality has been found with very limited oil and gas shows. Two potential candidates can be identified which are both within 100 km of Nyhamna. However, further detailed studies need to be conducted including potential data collections such as 3D seismic and information well, before it is possible to conclude on the suitability of these locations.

As part of the Halten CO_2 project work, a good storage candidate was identified, the so-called "Alpha" structure east of the Mikkel field. This location is some 225 km from Nyhamna and is shown on the Figure 5.5. A feasibility study was conducted on this location and is reported as part of the Halten CO_2 Project close out. Results of the work concluded that the "Alpha" structure in block 6407/6, warranted further evaluation of the structure as a CO_2 depository site as the data collection and evaluation revealed no large and irreducible risk factors. A cost estimate for a 225KM pipeline and umbilical has been made, adding a cost of 1600 mln NOK to the 150km estimate used as the base case. There is also potential for sites closer to the terminal site, perhaps 70km offshore. However, the targets identified lack good seismic coverage (mostly 2D) and therefore are less mature.

Selecting a storage site will be a choice between high cost - low risk and lower cost and higher risks. It could be preferable to invest in a longer pipeline to a more secure storage location than a closer and more risky location. This will be requiring further work.

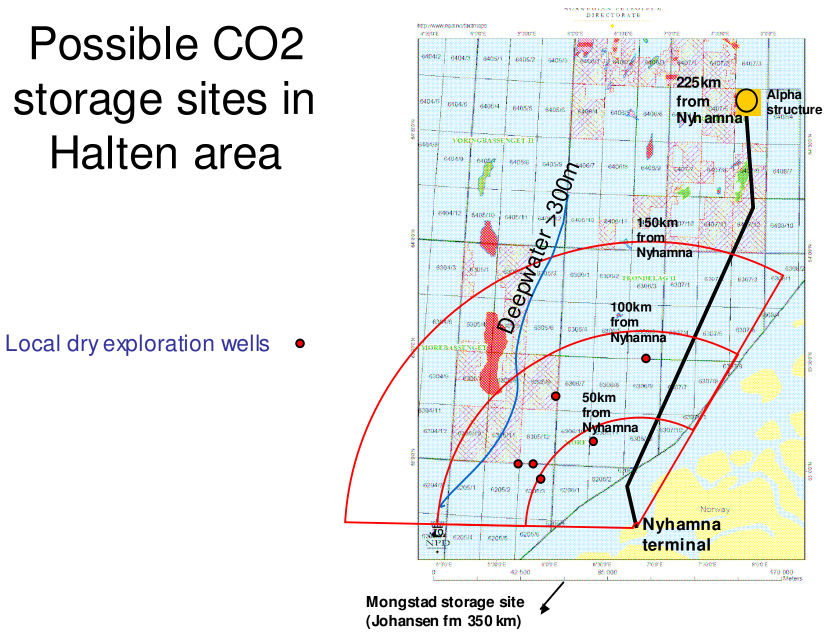


Figure 5.5 Potential storage sites

5.8 Cost estimates

5.8.1 CAPEX and OPEX estimates

Investment and operating cost estimates have been made for the power plant and CCS facilities, and can be found in Tables 5.4 and 5.5. These are unclassified, pre-screening phase, order of magnitude estimate with an accuracy of +50%/-25%. Further details can be found in Appendix C2.

MNOK RT2008	Cases			
	50	**200**	**430**	**860**
Power Plant 1)	1280	2930	4710	9130
Carbon Capture Plant 1)	1550	2975	4670	7430
Pipeline / Control line - 150km	3430	3430	3840	4470
Storage Wells	520	520	960	960

Table 5.4 Investment costs for PP + CCS cases

Note: 1) Site preparation costs are included in the power plant and carbon capture plant cost estimates on a 50/50 basis.

	MNOK RT2008	Cases 50	200	430	860
Power Plant	Fixed	3	13	28	57
	Variable Non Fuel	6	24	52	104
Carbon Capture Plant	Fixed	15	31	56	94
	Variable Non Energy	7	13	22	43
Pipeline	1.5% of Capex	34	34	55	45
Storage Wells	5% of Capex	17	17	32	32
Total costs	**Power plant**	**9**	**37**	**80**	**161**
	CCS	**73**	**96**	**165**	**214**

Table 5.5 Operating costs for each scenario

5.8.2 Investment cost inflation

There has been a substantial rise in equipment price levels since 2006, driven by a worldwide increase in the cost of raw materials, higher manufacturing costs, and growing market demand. For example, over the past few years copper has more than tripled, molybdenum – six-fold, aluminum - almost doubled, and nickel almost quadrupled.

This has resulted in a cost increase for gas turbine and CCGT plants of 25% to 35% over the last two years. The GTW handbook 2007-0813 claims that power plant equipment costs have increased by as much as 20% to 30% over pre-2006 levels. In addition the principal currency (dollar / euro / yen) exchange rates of the manufacturers have also been unstable during this period, which adds to price uncertainties.

5.8.3 Estimate Scope

The scope of the estimate is a Power Plant with Carbon Capture Plant sited at Nyhamna, associated CO_2 transportation pipeline and subsea storage wells.

An estimate has been completed for each of the Power Plant sizes under consideration: 50 MW, 200 MW, 430 MW and 860 MW.

Each estimate scope comprises the following components:

- Site Preparation
- Power Plant
- Carbon Capture Plant
- Pipeline
- Storage Wells

5.8.4 Technical Basis

Technical basis for the cost estimates is a number of technical studies commissioned by, or undertaken by Shell; some derived from the recent Halten CO_2 Project (HCP) and some specifically undertaken for Nyhamna, as follows:

	50 MW	200 MW	430 MW	860 MW
Site Preparation	Multikonsult HCP study for Tjeldbergodden / updated			
Power Plant	ESBi study for Nyhamna			
Carbon Capture Plant	MHI study for Nyhamna		MHI study for HCP / updated	
Pipeline / Control line	Shell CCS Offshore Technical Basis			
Storage Wells	Shell CCS Offshore Technical Basis			

Table 5.6 Technical basis for cost estimating

Cost estimates are based on a combination of preliminary and engineered inputs. The level of technical definition is above the norm for this level of estimate due to the use of HCP derived information.

5.8.5 Estimate Basis and Methodology

- The investment cost estimates have been initially developed as discrete building blocks in Real Term 2007 $.
- Building blocks for Site Preparation, Power Plant, Carbon Capture Plant, Pipeline and Storage Wells cover procurement, fabrication, installation and construction, commissioning, logistics, engineering design, project management.
- Building blocks are self-contained, there is no optimisation considered at this stage.
- Building blocks have been used to create scenario cost estimates for the “Base Case”, 150 km pipeline, and “Alternative” cases, 70 km and 225 km pipelines. An overall case cost estimate has been prepared for each case.
- A combination of consultant/contractor studies and Norske Shell cost models has been used to generate estimates.
- Cost estimates have been prepared on a current market basis for Norway (Norway location factor used).
- P50 contingency has been assessed at differing %ages for each building block based on level of technical definition.
- Future market developments are added to base estimates.
- Pre-FID (investment decision) costs are not included.

5.8.6 Exclusions

- Site acquisition
- Duties
- Taxes
- Subsidies
- Financing cost
- Exploration and appraisal cost
- Pre FEED and FEED studies

5.9 Schedule and underlying assumptions

A preliminary schedule can be found in Appendix C3. This assumes the following key milestones:

Project Final Investment Decision	01.07.2010
Power Plant start-up	01.01.2014
Capture plant start-up	01.04.2014

5.9.1 Schedule basis

The schedule is structured in accordance with the standard Shell Process, where the project is divided into the main development phases. Each phase commences with a Decision Gate (DG), where continuation of project execution is dependant on written approval from the Decision Review Board.

This Preliminary Project Schedule is generated at a high level (level 1) and indicates the time-phasing and interdependencies of each of the major facility groups:

- Site Preparation
- Power Plant (PP)
- CO_2 Capture Plant (CC)
- CO_2 Export Subsea Pipeline (PL)
- CO_2 Subsea Storage Well (SW)

5.10 Commercial model

The commercial model for the power station varies depending on capacity, as shown in Table 5.7.

Case	Commercial model	Owned and operated by	Location
50MW	Dedicated to phase 2 of Ormen Lange field development.	Ormen Lange (OL) unit	Likely on a Terminal site
200MW	Supplies power to Ormen Lange field development, sells excess to market. OL unit likely to have a long term contract for part or all of production	Industrial power company – providing power on contract basis to the OL Unit	Nyhamna terminal industrial area
430-860MW	Commercial scale power plant operating in the Nordpool power market. May have part of production contracted to LT users	Owner - Utility company or Independent Power Producer Operation – may be contracted out	Nyhamna terminal industrial area

Table 5.7 Power station commercial model

Figure 5.6 shows the basic commercial model for the power station, with flows of gas, power and CO_2. These elements are described individually in the next section.

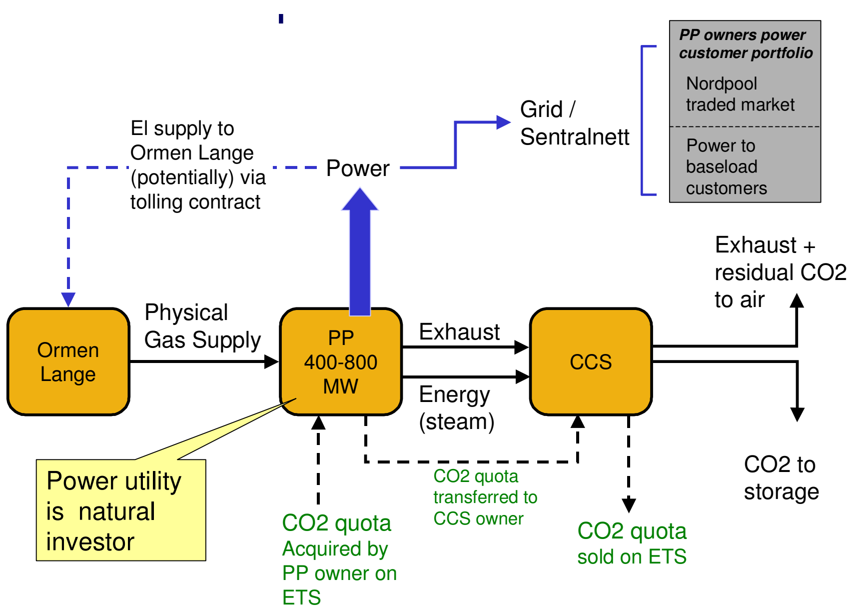


Figure 5.6 Basic commercial model (shown commercial scale power plant)

5.10.1 Gas supply

The gas supply to all Nyhamna power plant cases is assumed to come from the Ormen Lange terminal via pipeline to the power plant site.

5.10.2 Power sales

Power from the Nyhamna plant can be sold in a number of ways as shown in Table 5.8 – sales channels. We have chosen not to comment extensively on this section as it is outside Shell's direct experience and there are other companies better positioned to give a view.

50MW	200MW → 430MW → 860MW			
OL unit own use	Tolling, Contracting of capacity	Long-term contracts (industrial users)	Part of portfolio for larger utilities with production in Scandinavia (Nordpool)	Nordpool - Spot market (price taker)

Table 5.8 Power sales channels

Long-term contracts could be used as a tool in this case to share some of the regional benefits of new power production felt by large (industrial) consumers with the power plant developer. No account of such long-term arrangements is taken in the economic analysis of the power station.

5.10.3 CO_2 capture and storage interface

The addition of a CO_2 capture and storage facility has the following aspects from a commercial point of view:

- CO_2 quota transactions: Our proposed business model is that the power plant is held as separate entity to the CO_2 capture plant during operation. Commercially this means that the power plant pays for any CO_2 quota which is not allocated free (if any), equivalent to its emissions as any power plant operating with CO_2capture would.

  The power plant has no emissions, however, and in our model transfers the quota to the capture facilities. The CCS facilities then emit some CO_2 and quota is cancelled to reflect this, the remaining quota (80-90% of total received) can be sold on the EU Emissions Trading System market and provide income to the CCS facilities.

5.11 Location Synergies and Advantages

The advantages that may be accessed by locating a power plant in the Nyhmana area (either on Aukra or the nearby mainland) compared to elsewhere in the mid-Norway region has been considered and described below.

1. Access to fuel quality gas over the long term

This is the main advantage over any other location. Technical complexity and capital investment is reduced since the necessary fuel gas can be simply drawn off “upstream” of the Ormen Lange gas plant export compressors and piped to the power plant. Commercial complexity is also reduced since there are potentially several gas sellers capable of offering gas to a power plant, instead of current export markets, without the need for swaps or concerns of rich gas value compensations.

2. Access to gas export system

The Nyhamna plant is directly connected to Gassled sales gas Zone D with physical connection to the UK and continental main land markets. This means that during times when a power station is not operational, gas that would otherwise have been delivered to the power station has the potential to be exported. Commercially it implies a predictable choice of reference pricing for the gas supply to the power plant.

3. Clearer commercial arrangements

Ormen Lange plant has a significant, constant and relatively predictable demand for electrical power. If a commercially viable gas plant is developed, it may be possible for Ormen Lange to enter into long term arrangements for supply of fuel gas and purchase of electricity. There are various commercial models that could be applied, from traditional gas sales arrangement, to a tolling arrangement (where gas is supplied, a fee paid and electricity received) or a combination of the two.

4. Established Industrial Area

If the power plant were situated on Aukra itself near the Nyhamna plant, there is thought to be suitable area available outside the current fence (or in the case of a 50 MW power plant probably within fence) as well as convenient jetty infrastructure for material delivery for construction. There are convenient available connection points for electricity supply to the central grid.

5. Potential Hub for CO_2 handling

If a Power plant with a CCS faculty were developed near Nyhamna, there would be potential synergies for sharing of the CO_2transportation and storage facilities with potential future offshore hydrocarbon developments that contain high levels of CO_2. Such new developments would require their own CO_2 removal facilities since the technology for capturing CO_2 from exhaust gas and that from natural gas are different.

5.11.1 Technical and Operational synergies with Nyhmna terminal

In addition to the potential advantages above, there could also be some direct synergy effects with the operational and future developments at Nyhamna. These are discussed below:

1. Technical synergies

There may be potential services available from or to the Ormen Lange gas terminal if a power plant were developed near Nyhamna. These would need to be evaluated by the Ormen Lange operator, the power plant operator and the CO_2 capture, transport and storage operator. Examples could include:

- Utility services from Ormen Lange. E.g.cooling water capacity: an upgrade of Ormen Lange's infrastructure could be considered instead of the power plant and CCS facility buildings its own.
- Low Pressure Steam: The power plant will have available low pressure steam which could be made available to Ormen Lange as a back up or at lower running cost than the existing process heating system.
- Use of existing cable/overhead line connection to the Statnett system already provided by Ormen Lange
- Ormen Lange phase II (field pre compression) and power plant/CCS project development synergies for equipment purchases and delivery.
- Use of the pre installed landfall for a CO_2 pipeline

2. Operational Synergies

There appears to be some operational efficiency and reduced manning potential with respect to operational and maintenance activities if the power plant and CCS were located in the proximity of the Ormen Lange terminal at Nyhamna. These would need to be evaluated and are likely to be proportional to the size of the power plant built. For example, a small power plant dedicated to Ormen Lange in connection with pre compression would probably have a high degree of integration with the Ormen Lange operations including possibly control room facilities. However, a larger plant (430 MW and larger) would probably need to be operated by a separate operator and there may be only minor scope for manning synergies.

3. Environment

Locating a power plant near Nyhamna can be seen to have a negative environmental synergy effect in that the overall emission footprint of the Nyhamna area will go up significantly both in terms of CO_2 and other waste products such as used Amine from the CCS plant.

In the case of high integration there may also be some environmental impacts on Ormen Lange in how carbon cost and free allocations are applied due to linking a power industry facility with a petroleum industry facility.

6 Economics

6.1 Introduction

The objective of this chapter is to illustrate some of the economic challenges for developing a power plant for the different plant sizes and for various assumptions as described in Chapter 4, both with and without a carbon capture and storage facilities. In section 6.2 the relative economic attractiveness for a potential power plant investor is highlighted. This section also explores what the most significant variables are, and their impact on project economy and what combinations of those would be needed to achieve different target earning power percentages.

Section 6.3 illustrate the NPV cost of a CCS facility under differing carbon cost and allocation assumptions and tax regimes. Also shown is the discounted unit cost of capture and storage.

In Section 6.4 illustrates the combined economics of the power plant and CCS.

Section 6.5 discuss potential other indirect economic benefits if for example a 430 MW power plant with CCS facility was developed in the region.

6.2 Power station economics

The economics model optimizes the result of each case by only allowing the plant to run when there is a positive spark spread large enough to cover the variable operation costs (no contribution to capital depreciation). As a result, running time (load factors) for the four power plant sizes plants range from 52% to 74% with the base case assumptions. Figure 6.1 below illustrates this for the 430 MW case. It should be noted that the increasing spark spread over time is a reflection of the assumptions used whereby feed gas prices are kept flat whereas electricity prices increase in real terms. Variable operating cost (excluding gas feed cost) increases with time (blue line) due to rising CO_2 costs assumed in the base scenario. The rising CO_2 cost is predicted to also increase the electricity price due to higher CO_2 related cost of German coal fired power generation. As can be seen, the spark spread is positive nearly all the time (in red), but does not always cover variable operating costs. As the spark spread increases with time, the operational period (in green) is increasing.

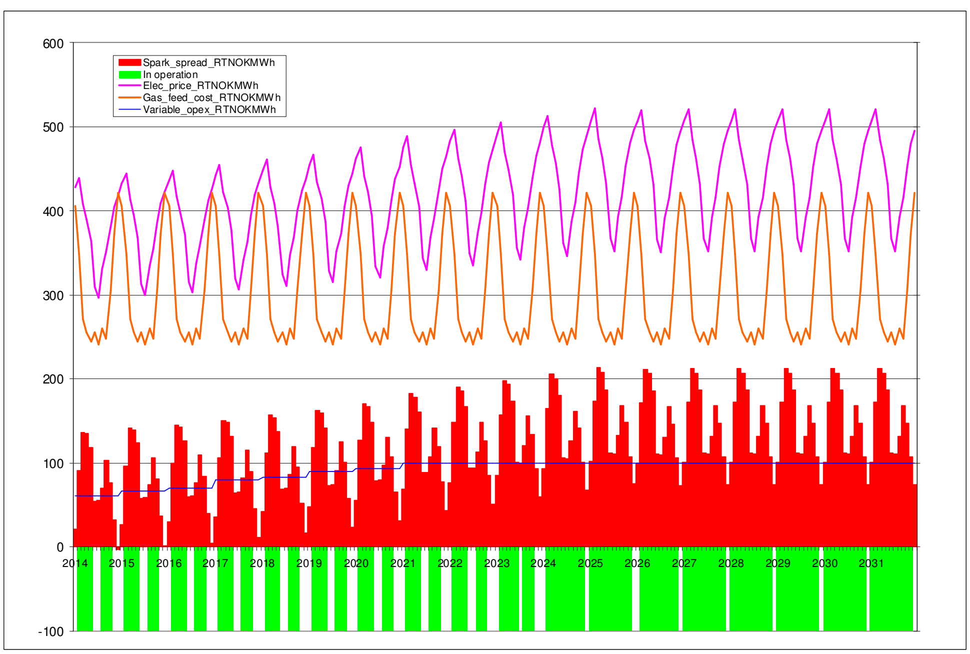


Figure 6.1 Illustration of Spark spread and uptime for 430 MW case.

Figure 6.2 below illustrates the relative impact on the NPV discounted at 7% of the different power plant sizes using the base case assumption for gas, electricity and carbon cost. None of the scenarios achieve positive NPV7 under base assumptions, and none break even at 0% discount rate. Tax rates dictate that a company in an offshore tax paying position would incur the smallest NPV loss, an onshore company a higher loss, while a company in a non tax paying position would bear the full NPV7 loss equivalent to the pre-tax NPV7 loss (a 20% higher exposure than a company in a tax paying position). The uptime percentage is also indicated for the various cases

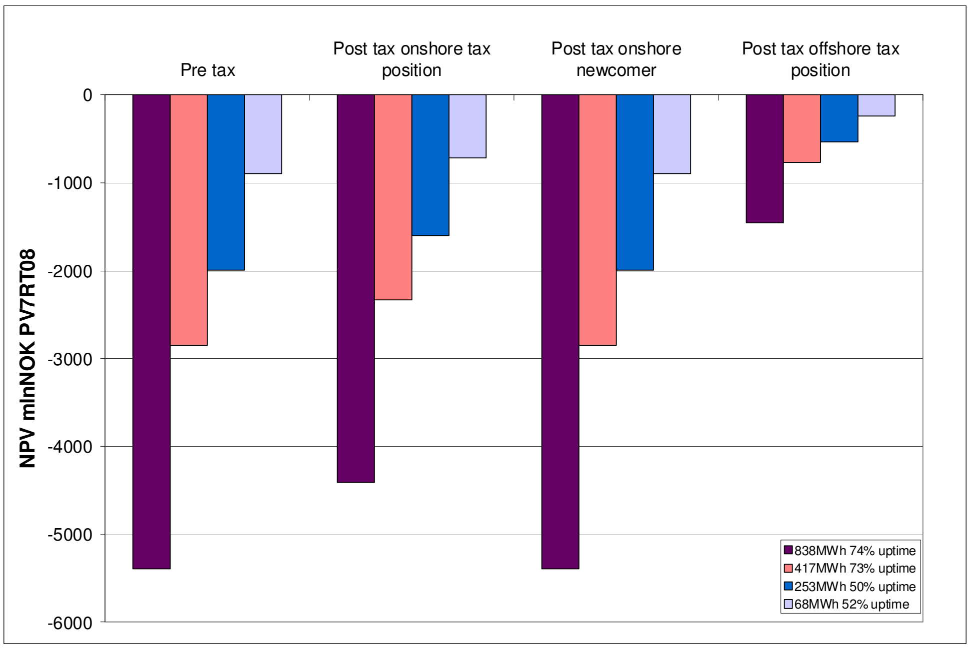


Figure 6.2 NPV impact of Power plant size and tax position, base case assumptions

Figure 6.3 below illustrates the sensitivities of the main elements for the 430 MW case. As expected, the most important variables are the electricity and gas price assumptions with capital cost and Carbon cost of secondary importance. Only in the high electricity price and low gas price scenarios does the project break even and achieve a positive RTEP (blue diamonds). The figure illustrates that there is more upside than downside for gas and electricity price, which is a result of the power station not running with negative net operating revenue. For example the low point shown in the gas price sensitivity represents a base average electricity price assumption of 417 NOK/MWh with high gas price assumption of 223 øre/m3 resulting in an uptime of only 15%. The plant would not run at all with gas prices above 244 øre/m3 and average electricity price 417 NOK/MWh).

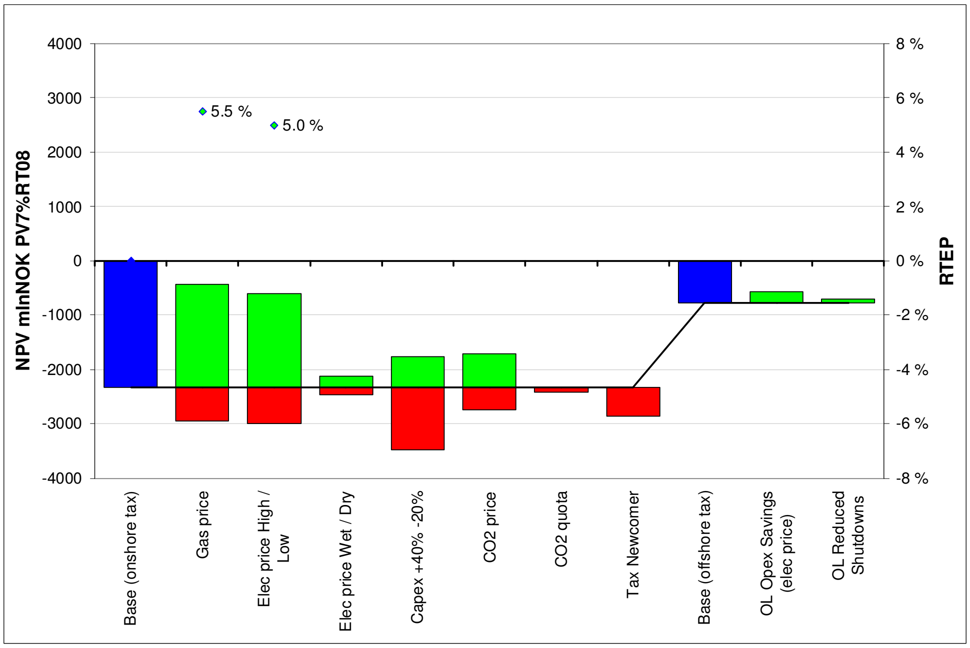


Figure 6.3 Sensitivities for the 430 MW case

Figure 6.4 below illustrates the relative impact of the two most important variables, fuel gas price and electricity price, and what is required in order to yield a certain RTEP to an investor in the 430 MW power plant case in an onshore tax paying position. The plot shows the range of gas and electricity price assumptions used in the study (grey box) with the base assumptions represented by the middle of the rectangle. The NBP gas future price shown in the graph is the average of winter and summer price as of March 31st data. The NBP gas future price of May 28th has increased considerably to approximately 304 øre/m3, indicating that the gas assumptions used in the study are conservative compared to current market views.

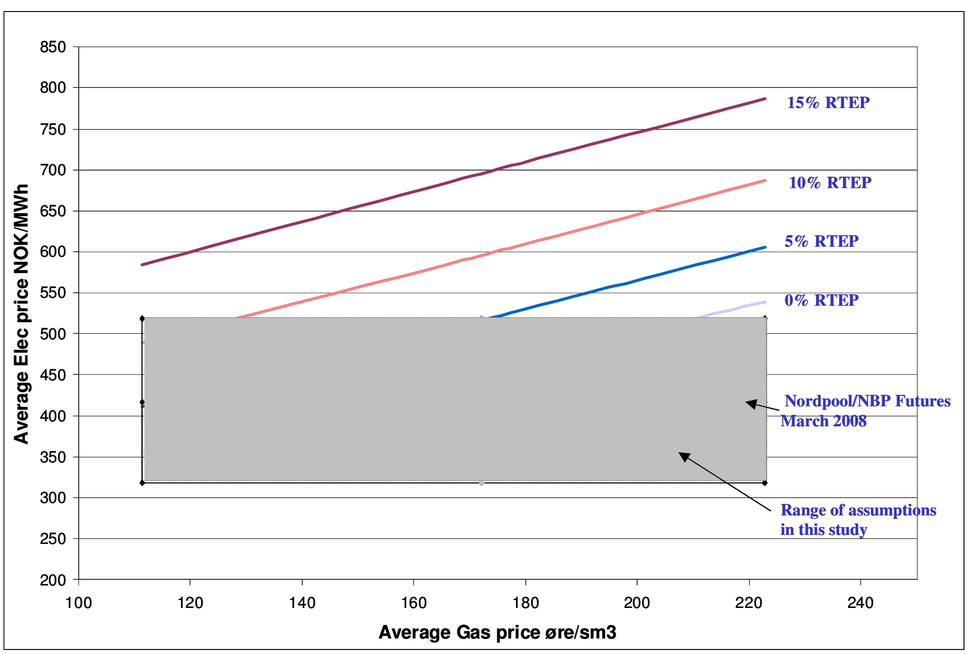


Figure 6.4 Required prices to obtain a certain RTEP for the 430 MW case

Figure 6.5 below shows the relationship between the gas and electricity prices for 10% RTEP for varying power plant size. The plot shows that below a certain power plant size, there is decreasing economic efficiency with decreasing size, i.e. the gap between the most efficient 860 MW plant and the 430 MW case is small, but becomes more noticeable in the 230 MW case, and is highly significant in the 50 MW case.

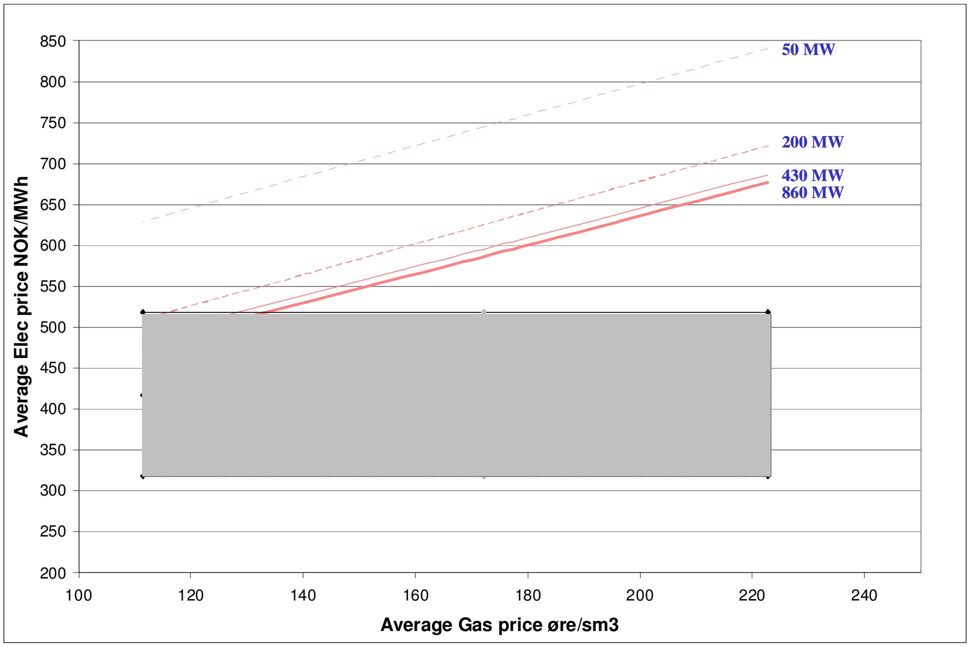


Figure 6.5 Required prices to obtain a 10% RTEP all power plant cases.

The above figures illustrate that there is a substantial gap that would need to be closed to make it attractive for a power plant investment.

An evaluation has been made to test whether there is an economic business case for Ormen Lange to invest in the 200 MW case, sufficient for Ormen Lange's long term needs. Any surplus power produced could be sold on the market. For this evaluation the base case gas and electricity prices (average 417 NOK/MWh) are used. As already shown in Figure 6.2, the starting point is that the investment has a negative NPV 7% value of approx minus 530 MNOK RT08, or 2 bln NOK pre-tax

In Figure 6.6 below illustrates how the Ormen Lange business case changes if such a power plant was invested in by Ormen Lange to avoid the risk of short power supply interruptions leading to shutdowns and higher electricity prices in the region. An optimistic assumption has been made that building a power plant and reducing power demand supply imbalance would ease electricity prices by 100 NOK/MWh over the entire 20 year period. In addition it is assumed that building a power station would avoid a worst case of 24hrs shutdown every year due to power interruptions, with the gas being produced six months later in the summer. The NVP7 savings improves the business case does but does not reach breakeven.

One can therefore conclude that even if a new power station would reduce the risk of supply interruptions and reduce the NO2 price differential to zero, the benefit to Ormen Lange is not sufficient to warrant capital investment by the Ormen Lange owners in a power station.

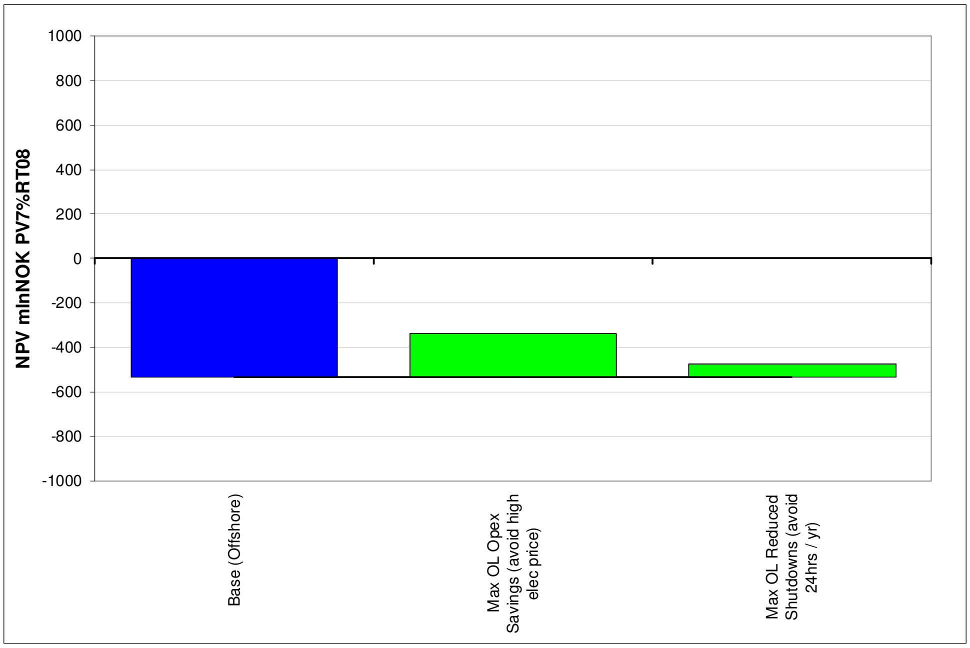


Figure 6.6 NPV 7% of 200 MW Case, base assumptions, offshore tax and potential benefits for Ormen Lange.

6.3 Capture and storage (CCS)

As described in section 5.10, the assumption of CO_2 quota treatment is that the Power plant will have to obtain carbon quota (via purchase and/or free allocation) for the CO_2 it will generate. The investor in a carbon capture plant should be "paid" by the power plant through transfer of the CO_2 quotas or an equivalent fee. The capture plant owner would then be able to trade the CO_2 credits to generate an income equivalent to the value of the CO_2 volumes stored. The income from this is relatively small compared to the operating and capital cost, as illustrated in Figure 6.7 below by the green column (operating revenue).

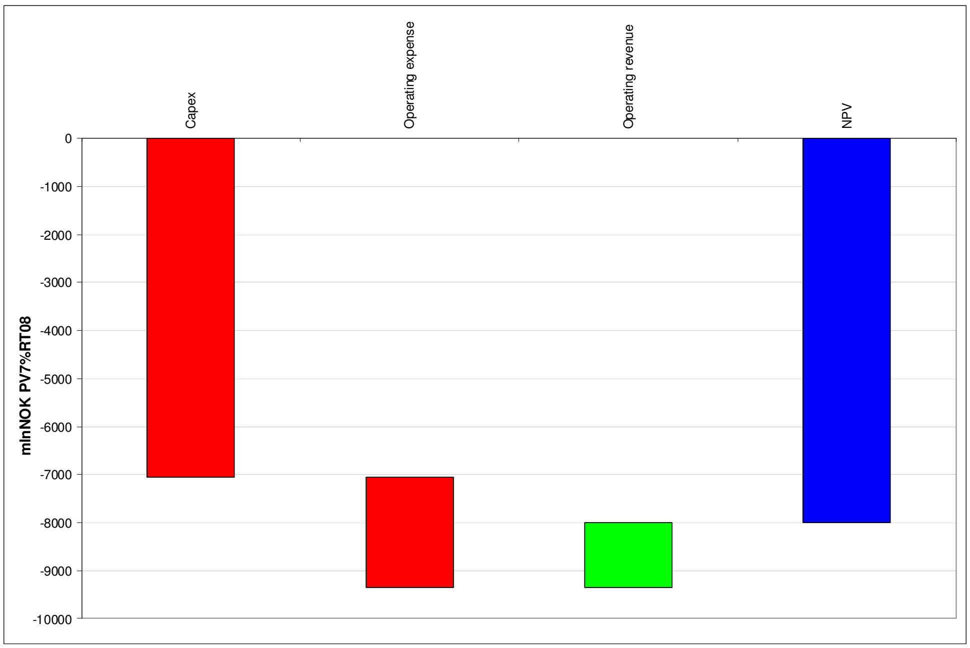


Figure 6.7 Carbon Capture economics for 430 MW case

Figure 6.8 below illustrates the relative NPV for the different CCS plants associated with the power plant sizes.

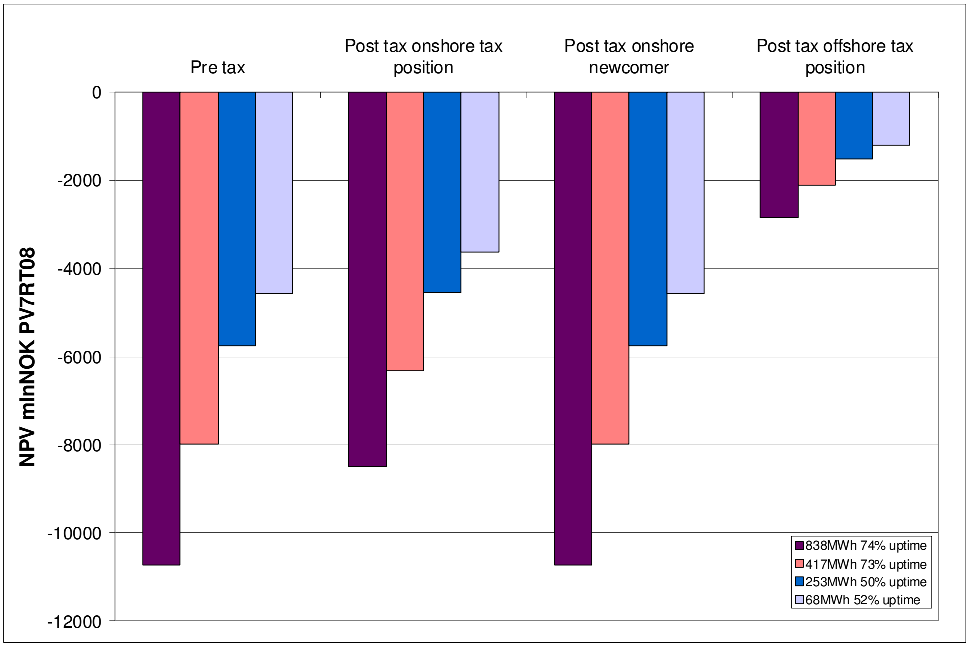


Figure 6.8 NPV 7% cost of CCS facilities size and tax position, base assumptions

A key observation from the above figures is that under the assumptions applied, a commercial investor would not consider it interesting to invest in a CCS facility. It can be estimated that the CO_2 price required for the CCS for the 430 MW case would be 770 NOK/T (or over three times the base case assumption of 230 NOK/T) to break even at 0% discount (including both operating and investment cost).

The CCS investment increases with increasing power plant size, and hence the NPV becomes more negative. However, Table 6.1 below illustrates that the larger CCS facilities have a significantly lower unit technical cost, both with and without the investment element included.

Power plant nominal & (installed) MW	860 MW (838MW)	430 MW (417MW)	200 MW (253MW)	50 MW (67MW)
CCS system power consumption (MW)	118	56	39	10
Unit technical cost (PV 7% Capex mil $'08 /PV7% mil T CO_2)	106	156	183	535
Unit technical cost (PV 7% Capex + Opex mil $'08 /PV7% mil T CO_2)	158	216	243	640

Table 6.1 Technical Unit Cost for CCS

Figure 6.9 below shows the relative impact on the NPV by the different variables of capital cost and CO_2 income levels. It can be seen that the value CO_2 credits is immaterial to the economics at the assumption range levels.

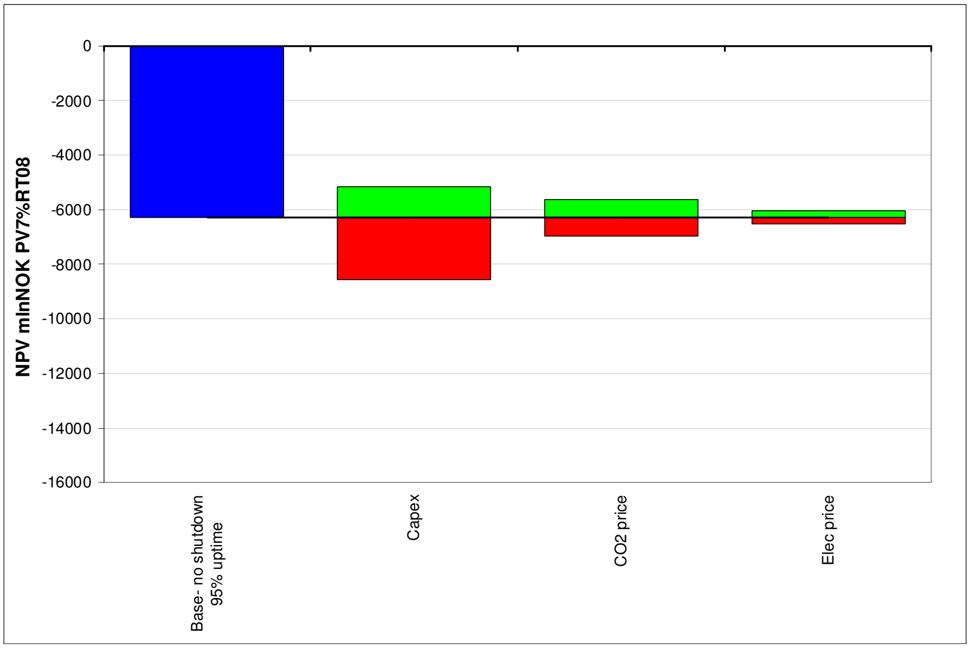


Fig 6.9 NPV 7% sensitivity from extreme assumptions 430 MW case

6.4 Combined system

To summarise the total economic picture for the PP/CCS cases, Figure 6.10 below illustrates the combined NPV 7%, post onshore tax, for both the power plant and the CCS facilities with base case assumptions. It can be seen that the relative cost of CCS compared to the power plant cost is greatest for the smaller sized power plants. It can be concluded that to apply CCS facilities to smaller power plants is very costly and inefficient.

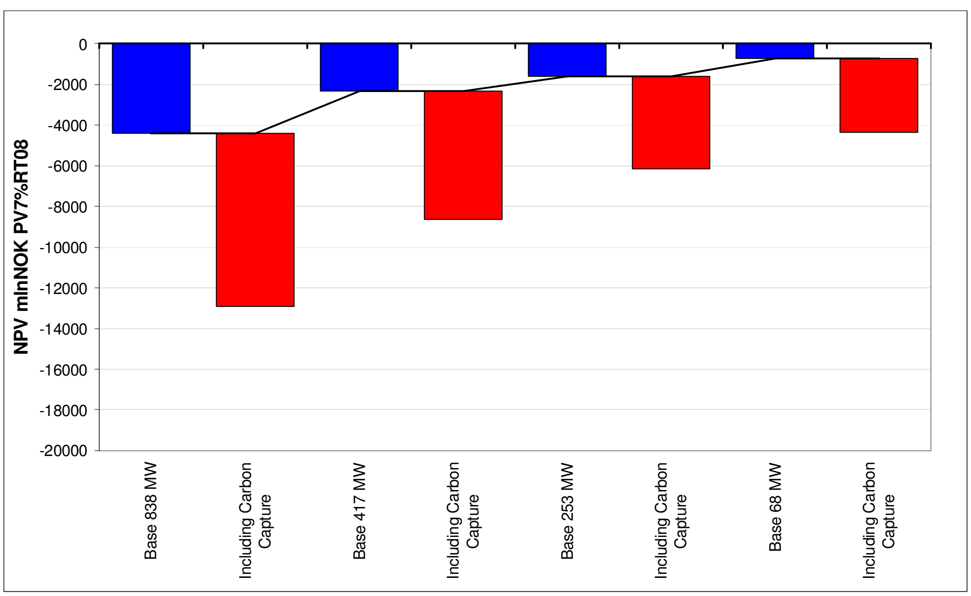


Figure 6.10 Comparison of combined power plant and CCS, all PP/CCS cases

6.5 Other benefits of a power station in mid- Norway

To add to the economic evaluations, some considerations have also been made with regards to potential other benefits of establishing a new power station in mid-Norway. These socio-economic benefits would not have a direct impact on the commercial viability of a power plant. The considerations are based on study work carried out during the Halten CO_2 Project (Ref 6.3), and other public domain sources. The size of any benefit would clearly depend on the size of the installation; i.e. with the 50MW plant having little or no effect outside those already discussed, as it would be dedicated to supply the Ormen Lange field. This analysis has been done at a qualitative level and a more detailed study would be required to determine exact values.

It is assumed that the power station would operate as a (near) base-load producer, in normal and dry years. The cases 200, 430 and 860MW should be seen as contributing power to the mid-Norway price area, as even if part or all of their capacity is used by the Ormen Lange field it would create a corresponding offset in the regional supply-demand balance.

A 430 MW power plant with CCS would provide circa 3.0 TWh/year additional local production (after consumption by the CCS facility), which would reduce the import requirement by a corresponding amount (total import is ~9 TWh in a normal year post 2012 (Ref 6.2)).

1. Transmission Net loss reduction

Increased local power production will result in reduced grid losses as less power is imported into the region over long distances. This would most likely lower grid charges to all consumers. Based on the average difference between a high import period in the area (Q1 2007) and low import period (Q1 2008) the reduction in losses is estimated to be approximately 2%.

2. Replacement of Reserve power stations

A new power station of 430MW or larger would make it possible to remove the two Reserve power stations (150 MW) currently being installed at Nyhamna and Tjeldbergodden. These have a low efficiency and are planned only to be used when there is a risk of rationing of power supply. The 430MW power station is more efficient, resulting in less gas consumption for the equivalent output as from the Reserve power stations.

3. Removal or reuse of Reserve power stations

As stated above, building of a new commercial scale power station would allow removal of Statnett's Reserve stations. These could be sold or redeployed.

4. Security of supply

A new power plant in the area would most likely lower load stresses on the regional net and thereby reduce the risk of interruptions of supply and the economic consequence that may have to industrial users and to domestic consumers.

5. Improved national supply-demand balance

New capacity in the region would reduce the need for power imports from European coal generated power. There would be a net CO_2 benefit from doing this.

6. Encourage local investment

There is currently low confidence in mid-Norway's security of supply situation, as evidenced by local industry and political stakeholders making public their concern. This uncertainty may be preventing decisions for new industrial investments requiring substantial power supply.

7. Price effects

If new commercial scale power generation is constructed in mid-Norway (430MW+), it will operate on different principles to the Reserve power stations, in particular being steered by price and not chance of rationing which should result in additional power being produced at a much earlier point. This would most likely lower the risk of very high prices in dry years in price area NO2.

7 Conclusions

Regional power deficit in Mid Norway

The gap between generation and consumption in the mid-Norway region is some 8 to 12 TWh per year depending on reservoir filling, and approx 50% of all the power consumed is imported to the region. Statnett is in the process of implementing measures to close the gap through expansion of the import grid (Ørskog - Fardal line), SAKS and installing 2 x 150 MW reserve power plants. If there is a delay in the new import line, the reserve power plants will probably be needed in a dry year situation. Otherwise, with a modest 0.5% growth in demand assumption, the region should be sufficiently supplied until approximately 2020 assuming there are also some 2 TWh of renewable developments. As an alternative, for example a 430 MW or larger sized power plant would improve security of local supply as well as allow for greater demand growth.

No business case to invest in power capacity.

The economics clearly show that there is no business case to invest in any of the power plant sizes evaluated. The main reasons for the poor economics are the current high cost level and expected prices both for gas and electricity. This conclusion also applies for a power plant covering the needs of Ormen Lange for Phase I and II, which potentially could reduce the risk for Ormen Lange to be exposed to high electricity prices as well as reduce the risk for plant shut downs due to power supply interruptions.

Clarification of CCS requirement and framework

Investing in a gas-fired power plant, even without CO_2 handling facilities (CCS), is to day highly challenging. The potential requirements for CO_2 handling creates an additional uncertainty for the power plant investor and it would therefore be necessary that the framework around CO_2 handling is clarified as far as possible to create the right environment for investments in power capacity.

8 References

Chapter 3

3.1 Statnett - Kraftsituasjonen i Midt-Norge – mid'07

3.2 Evaluering av ordningen med energiopsjoner i forbruk for sesongen 2007/2008 13. mars 2008. (Energy Options evaluation for 2007/08).

Chapter 6

6.1 Halten CO_2 Project – reports and evaluations. Shell-StatoilHydro 2006/07/08

6.2 Sources provided by the MPE to Shell, January to May 2008

6.3 ECON report "Socio economic effects of the Halten CO_2 Project" dated December 2006

6.4 NVE report on decision on IKM 450 MW power plant concession application, dated March 2008

6.5 420 KV LEDNING ØRSKOG – FARDAL KABELUTREDNING Jan 2007

Attachments

A. Regional supply-demand analysis

B. Economic / evaluation assumptions

C. Technical data

Appendix A1. Mid-Norway supply-demand balances

Scenario 1 - Reference scenario - no further growth in power supply post 2008

Mid norway Supply - demand balance

Supply-Demand TWh, -ve = deficit | 0-1 | -1 to -2 | > -2

	El Grid util %		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NORMAL YR	60 %	0% growth, P50 yr	-0,1	0,4	-0,8	-0,6	0,0	-0,4	-0,5	-0,4	-0,4	-0,5	-0,6	-0,6	-0,7	-0,8	-0,8	-0,8
NORMAL YR	60 %	0,5% growth, P50 yr	-0,1	0,4	-0,8	-0,6	-0,1	-0,6	-0,7	-0,6	-0,7	-0,8	-0,9	-1,1	-1,2	-1,4	-1,4	-1,5
NORMAL YR	60 %	1,8% growth, P50 yr	-0,1	0,4	-0,8	-0,6	-0,2	-0,8	-1,1	-1,2	-1,4	-1,7	-1,9	-2,2	-2,5	-2,8	-3,1	-3,3
NORMAL YR	70 %	0% growth, P50 yr	1,1	1,6	0,2	0,6	1,4	0,9	0,9	1,0	0,9	0,9	0,8	0,7	0,6	0,5	0,5	0,5
NORMAL YR	70 %	0,5% growth, P50 yr	1,1	1,6	0,2	0,6	1,3	0,8	0,7	0,8	0,7	0,6	0,4	0,3	0,2	0,0	0,0	-0,1
NORMAL YR	70 %	1,8% growth, P50 yr	1,1	1,6	0,2	0,6	1,2	0,6	0,3	0,2	0,0	-0,3	-0,6	-0,9	-1,2	-1,5	-1,7	-1,9
NORMAL YR	80 %	0% growth, P50 yr	2,3	2,8	1,2	1,8	2,7	2,3	2,3	2,3	2,3	2,3	2,2	2,1	2,0	1,9	1,9	1,9
NORMAL YR	80 %	0,5% growth, P50 yr	2,3	2,8	1,2	1,8	2,7	2,2	2,1	2,1	2,1	1,9	1,8	1,7	1,5	1,4	1,3	1,3
NORMAL YR	80 %	ECON case, P50 yr	2,3	2,8	1,2	1,8	2,7	2,1	1,8	1,7	1,6	1,3	1,1	0,9	0,7	0,5	0,4	0,3
DRYYEAR	60 %	0% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-2,9	-3,4	-3,4	-3,3	-3,3	-3,4	-3,5	-3,5	-3,6	-3,7	-3,7	-3,7
DRYYEAR	60 %	0,5% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-3,0	-3,5	-3,6	-3,5	-3,6	-3,7	-3,8	-4,0	-4,1	-4,3	-4,3	-4,4
DRYYEAR	60 %	1,8% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-3,1	-3,7	-4,0	-4,1	-4,3	-4,6	-4,8	-5,1	-5,4	-5,7	-6,0	-6,2
DRYYEAR	70 %	0% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,5	-2,0	-2,0	-1,9	-2,0	-2,0	-2,1	-2,2	-2,3	-2,3	-2,4	-2,4
DRYYEAR	70 %	0,5% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,6	-2,1	-2,2	-2,2	-2,2	-2,3	-2,5	-2,6	-2,7	-2,9	-2,9	-3,0
DRYYEAR	70 %	1,8% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,7	-2,4	-2,6	-2,7	-2,9	-3,2	-3,5	-3,8	-4,1	-4,4	-4,6	-4,8
DRYYEAR	80 %	0% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,17	-0,6	-0,7	-0,6	-0,6	-0,6	-0,7	-0,8	-0,9	-1,0	-1,0	-1,0
DRYYEAR	80 %	0,5% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,22	-0,7	-0,8	-0,8	-0,8	-1,0	-1,1	-1,2	-1,4	-1,5	-1,6	-1,6
DRYYEAR	80 %	1,8% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,36	-1,0	-1,2	-1,3	-1,5	-1,8	-2,1	-2,4	-2,7	-3,0	-3,2	-3,5

Case selection

Infrastructure case	3	Case 3 : Ø-F not built
Hydro case	1	Case 1 : No growth 2008+
Wind case	1	Case 1 : No growth 2008+
Power station case	1	No power plant

Scenario 2 - As planned

Mid norway Supply - demand balance

Supply-Demand TWh, -ve = deficit 0-1 | -1 to -2 | > -2

	El Grid util %		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NORMAL YR	60 %	0% growth, P50 yr	-0,1	0,4	-0,8	-0,4	0,4	0,2	0,3	2,7	2,8	2,9	3,0	3,1	3,2	3,3	3,5	3,6
	60 %	0,5% growth, P50 yr	-0,1	0,4	-0,8	-0,4	0,3	0,1	0,2	2,4	2,6	2,6	2,7	2,7	2,7	2,8	2,9	3,0
	60 %	1,8% growth, P50 yr	-0,1	0,4	-0,8	-0,4	0,2	-0,2	-0,2	1,9	1,9	1,8	1,7	1,5	1,4	1,3	1,2	1,2
	70 %	0% growth, P50 yr	1,1	1,6	0,2	0,8	1,7	1,6	1,7	4,4	4,5	4,6	4,8	4,8	4,9	5,0	5,2	5,3
	70 %	0,5% growth, P50 yr	1,1	1,6	0,2	0,8	1,7	1,5	1,6	4,2	4,3	4,3	4,4	4,4	4,5	4,5	4,6	4,7
	70 %	1,8% growth, P50 yr	1,1	1,6	0,2	0,8	1,6	1,2	1,1	3,6	3,6	3,5	3,4	3,3	3,1	3,0	2,9	2,9
	80 %	0% growth, P50 yr	2,3	2,8	1,2	2,0	3,1	3,0	3,1	6,1	6,3	6,4	6,5	6,6	6,7	6,7	6,9	7,1
	80 %	0,5% growth, P50 yr	2,3	2,8	1,2	2,0	3,1	2,9	2,9	5,9	6,0	6,0	6,1	6,1	6,2	6,2	6,3	6,4
	80 %	ECON case, P50 yr	2,3	2,8	1,2	2,0	3,0	2,7	2,6	5,5	5,5	5,5	5,4	5,4	5,4	5,3	5,4	5,4
DRYYEAR	60 %	0% growth, dry yr	-2,8	-2,5	-3,7	-3,4	-2,6	-2,8	-2,7	-0,5	-0,3	-0,3	-0,2	-0,1	-0,1	-0,1	0,1	0,2
	60 %	0,5% growth, dry yr	-2,8	-2,5	-3,7	-3,4	-2,7	-2,9	-2,9	-0,7	-0,6	-0,6	-0,6	-0,6	-0,6	-0,6	-0,5	-0,4
	60 %	1,8% growth, dry yr	-2,8	-2,5	-3,7	-3,4	-2,8	-3,2	-3,3	-1,2	-1,3	-1,4	-1,6	-1,7	-1,9	-2,1	-2,2	-2,3
	70 %	0% growth, dry yr	-1,6	-1,3	-2,7	-2,2	-1,2	-1,5	-1,4	1,2	1,4	1,4	1,5	1,6	1,6	1,7	1,8	1,9
	70 %	0,5% growth, dry yr	-1,6	-1,3	-2,7	-2,2	-1,3	-1,6	-1,5	1,0	1,1	1,1	1,2	1,1	1,1	1,1	1,2	1,3
	70 %	1,8% growth, dry yr	-1,6	-1,3	-2,7	-2,2	-1,4	-1,8	-1,9	0,5	0,4	0,3	0,1	0,0	-0,2	-0,4	-0,5	-0,5
	80 %	0% growth, dry yr	-0,4	-0,1	-1,7	-1,0	0,13	-0,1	0,0	3,0	3,1	3,2	3,2	3,3	3,3	3,4	3,5	3,6
	80 %	0,5% growth, dry yr	-0,4	-0,1	-1,7	-1,0	0,08	-0,2	-0,2	2,8	2,8	2,8	2,9	2,9	2,9	2,9	2,9	3,0
	80 %	1,8% growth, dry yr	-0,4	-0,1	-1,7	-1,0	-0,06	-0,5	-0,6	2,2	2,1	2,0	1,9	1,7	1,5	1,4	1,3	1,2

Case selection

Infrastructure case	1	Case 1 : Ø-F on time
Hydro case	3	Case 3 : 1,7TWh 2008-2020 (ECON case)
Wind case	2	Case 2: 0.5 TWh 2008-2020
Power station case	1	No power plant

Scenario 3 - Delays

Mid norway Supply - demand balance

Supply-Demand TWh, -ve = deficit | 0-1 | -1 to -2 | > -2

	El Grid util %		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NORMAL YR	60 %	0% growth, P50 yr	-0,1	0,4	-0,8	-0,6	0,1	-0,2	-0,2	-0,1	0,0	0,0	0,0	2,1	2,1	2,1	2,1	2,2
	60 %	0,5% growth, P50 yr	-0,1	0,4	-0,8	-0,6	0,1	-0,4	-0,4	-0,3	-0,2	-0,3	-0,3	1,7	1,6	1,5	1,6	1,6
	60 %	1,8% growth, P50 yr	-0,1	0,4	-0,8	-0,6	-0,1	-0,6	-0,8	-0,8	-1,0	-1,1	-1,3	0,5	0,3	0,1	-0,1	-0,3
	70 %	0% growth, P50 yr	1,1	1,6	0,2	0,6	1,5	1,1	1,2	1,3	1,4	1,4	1,4	3,8	3,8	3,8	3,9	3,9
	70 %	0,5% growth, P50 yr	1,1	1,6	0,2	0,6	1,4	1,0	1,0	1,1	1,1	1,1	1,0	3,4	3,3	3,3	3,3	3,3
	70 %	1,8% growth, P50 yr	1,1	1,6	0,2	0,6	1,3	0,7	0,6	0,6	0,4	0,2	0,0	2,2	2,0	1,8	1,6	1,5
	80 %	0% growth, P50 yr	2,3	2,8	1,2	1,8	2,9	2,5	2,5	2,7	2,8	2,8	2,8	5,5	5,5	5,5	5,6	5,7
	80 %	0,5% growth, P50 yr	2,3	2,8	1,2	1,8	2,8	2,4	2,4	2,5	2,5	2,5	2,4	5,1	5,0	5,0	5,0	5,0
	80 %	ECON case, P50 yr	2,3	2,8	1,2	1,9	2,8	2,3	2,1	2,1	2,0	1,9	1,7	4,4	4,2	4,1	4,1	4,0
DRYYEAR	60 %	0% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-2,8	-3,2	-3,2	-3,0	-3,0	-3,0	-3,0	-1,0	-1,0	-1,0	-1,0	-0,9
	60 %	0,5% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-2,9	-3,3	-3,3	-3,3	-3,3	-3,3	-3,4	-1,4	-1,5	-1,5	-1,5	-1,5
	60 %	1,8% growth, dry yr	-2,8	-2,5	-3,7	-3,5	-3,0	-3,6	-3,8	-3,8	-4,0	-4,2	-4,4	-2,5	-2,8	-3,0	-3,2	-3,4
	70 %	0% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,5	-1,8	-1,8	-1,7	-1,6	-1,6	-1,6	0,8	0,7	0,7	0,8	0,8
	70 %	0,5% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,5	-1,9	-2,0	-1,9	-1,9	-1,9	-2,0	0,3	0,3	0,2	0,2	0,2
	70 %	1,8% growth, dry yr	-1,6	-1,3	-2,7	-2,3	-1,6	-2,2	-2,4	-2,4	-2,6	-2,8	-3,0	-0,8	-1,1	-1,3	-1,5	-1,7
	80 %	0% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,08	-0,5	-0,4	-0,3	-0,2	-0,3	-0,3	2,5	2,4	2,4	2,5	2,5
	80 %	0,5% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,13	-0,6	-0,6	-0,5	-0,5	-0,6	-0,6	2,1	2,0	1,9	1,9	1,9
	80 %	1,8% growth, dry yr	-0,4	-0,1	-1,7	-1,1	-0,27	-0,8	-1,0	-1,1	-1,2	-1,4	-1,6	0,9	0,6	0,4	0,2	0,1

Case selection

Infrastructure case	2	Case 2 : Ø-F 4 yrs late
Hydro case	2	Case 2 : 0.5TWh 2008-2020
Wind case	2	Case 2: 0.5 TWh 2008-2020
Power station case	1	No power plant

Scenario 4 - More renewables

Mid norway Supply - demand balance

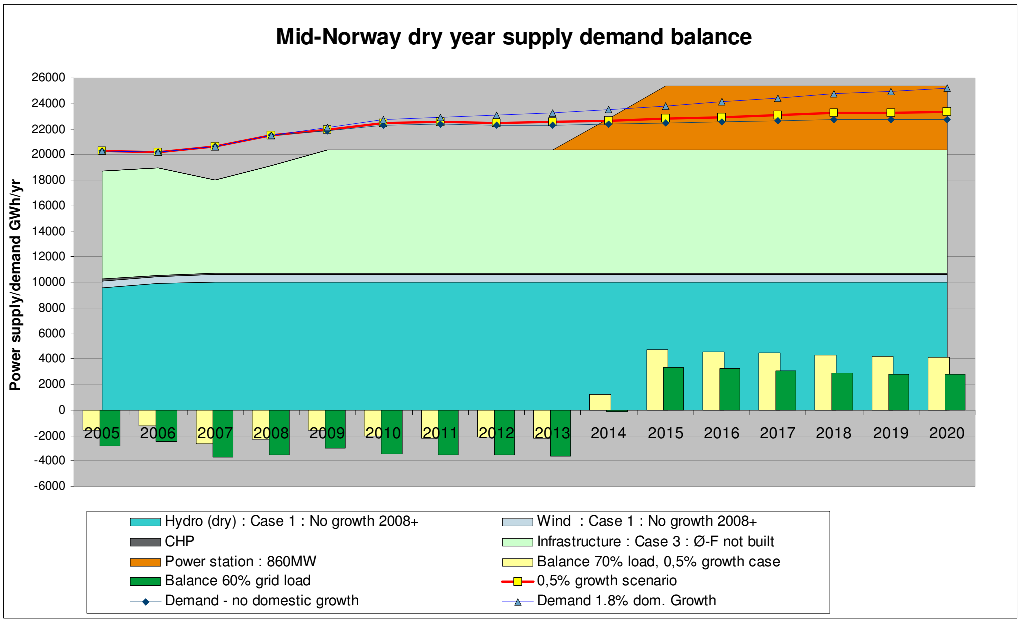
Supply-Demand TWh, -ve = deficit 0-1 | -1 to -2 | > -2

	El Grid util %		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NORMAL YR	60 %	0% growth, P50 yr	-0,1	0,4	-0,8	-0,3	0,5	0,4	0,7	1,1	1,4	1,6	1,8	4,1	4,3	4,5	4,8	5,1
NORMAL YR	60 %	0,5% growth, P50 yr	-0,1	0,4	-0,8	-0,3	0,4	0,3	0,5	0,9	1,1	1,3	1,5	3,7	3,9	4,0	4,3	4,5
NORMAL YR	60 %	1,8% growth, P50 yr	-0,1	0,4	-0,8	-0,3	0,3	0,1	0,1	0,3	0,4	0,4	0,5	2,5	2,5	2,5	2,6	2,7
NORMAL YR	70 %	0% growth, P50 yr	1,1	1,6	0,2	0,9	1,8	1,8	2,1	2,4	2,7	3,0	3,2	5,8	6,1	6,3	6,6	6,8
NORMAL YR	70 %	0,5% growth, P50 yr	1,1	1,6	0,2	0,9	1,8	1,7	1,9	2,2	2,5	2,7	2,8	5,4	5,6	5,7	6,0	6,2
NORMAL YR	70 %	1,8% growth, P50 yr	1,1	1,6	0,2	0,9	1,7	1,4	1,5	1,7	1,8	1,8	1,8	4,3	4,2	4,2	4,3	4,4
NORMAL YR	80 %	0% growth, P50 yr	2,3	2,8	1,2	2,1	3,2	3,2	3,4	3,8	4,1	4,3	4,6	7,6	7,8	8,0	8,3	8,6
NORMAL YR	80 %	0,5% growth, P50 yr	2,3	2,8	1,2	2,1	3,2	3,1	3,3	3,6	3,9	4,0	4,2	7,1	7,3	7,4	7,7	7,9
NORMAL YR	80 %	ECON case, P50 yr	2,3	2,8	1,2	2,2	3,1	2,9	3,0	3,2	3,4	3,4	3,5	6,4	6,5	6,6	6,8	6,9
DRYYEAR	60 %	0% growth, dry yr	-2,8	-2,5	-3,7	-3,3	-2,5	-2,7	-2,5	-2,2	-1,9	-1,8	-1,6	0,6	0,7	0,9	1,1	1,3
DRYYEAR	60 %	0,5% growth, dry yr	-2,8	-2,5	-3,7	-3,3	-2,6	-2,8	-2,6	-2,4	-2,2	-2,1	-2,0	0,2	0,3	0,4	0,5	0,7
DRYYEAR	60 %	1,8% growth, dry yr	-2,8	-2,5	-3,7	-3,3	-2,7	-3,0	-3,1	-2,9	-2,9	-3,0	-3,0	-1,0	-1,1	-1,1	-1,1	-1,1
DRYYEAR	70 %	0% growth, dry yr	-1,6	-1,3	-2,7	-2,1	-1,2	-1,3	-1,1	-0,8	-0,6	-0,4	-0,2	2,3	2,5	2,6	2,8	3,0
DRYYEAR	70 %	0,5% growth, dry yr	-1,6	-1,3	-2,7	-2,1	-1,2	-1,4	-1,3	-1,0	-0,8	-0,7	-0,6	1,9	2,0	2,1	2,2	2,4
DRYYEAR	70 %	1,8% growth, dry yr	-1,6	-1,3	-2,7	-2,1	-1,4	-1,7	-1,7	-1,6	-1,5	-1,6	-1,6	0,7	0,7	0,6	0,6	0,6
DRYYEAR	80 %	0% growth, dry yr	-0,4	-0,1	-1,7	-0,9	0,20	0,1	0,3	0,6	0,8	1,0	1,1	4,0	4,2	4,3	4,5	4,8
DRYYEAR	80 %	0,5% growth, dry yr	-0,4	-0,1	-1,7	-0,9	0,15	0,0	0,1	0,4	0,5	0,6	0,8	3,6	3,7	3,8	4,0	4,1
DRYYEAR	80 %	1,8% growth, dry yr	-0,4	-0,1	-1,7	-0,9	0,02	-0,3	-0,3	-0,2	-0,2	-0,2	-0,2	2,4	2,4	2,3	2,3	2,3

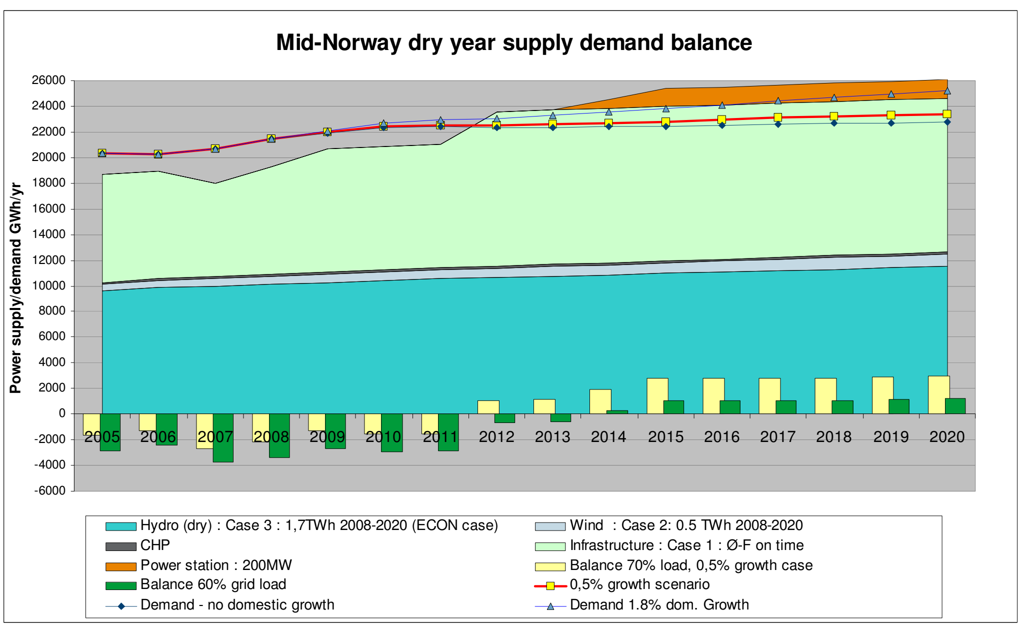
Case selection

Infrastructure case	2	Case 2 : Ø-F 4 yrs late
Hydro case	3	Case 3 : 1,7TWh 2008-2020 (ECON case)
Wind case	3	Case 3 : Big growth 2 TWh
Power station case	1	No power plant

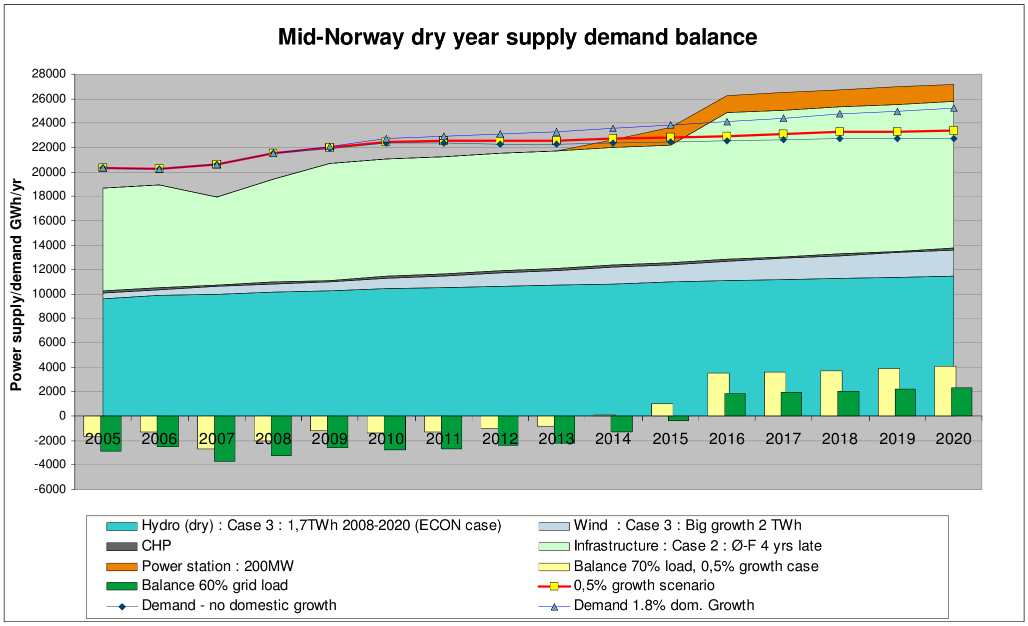
Appendix A2. Power supply-demand balance graphs for each scenario.



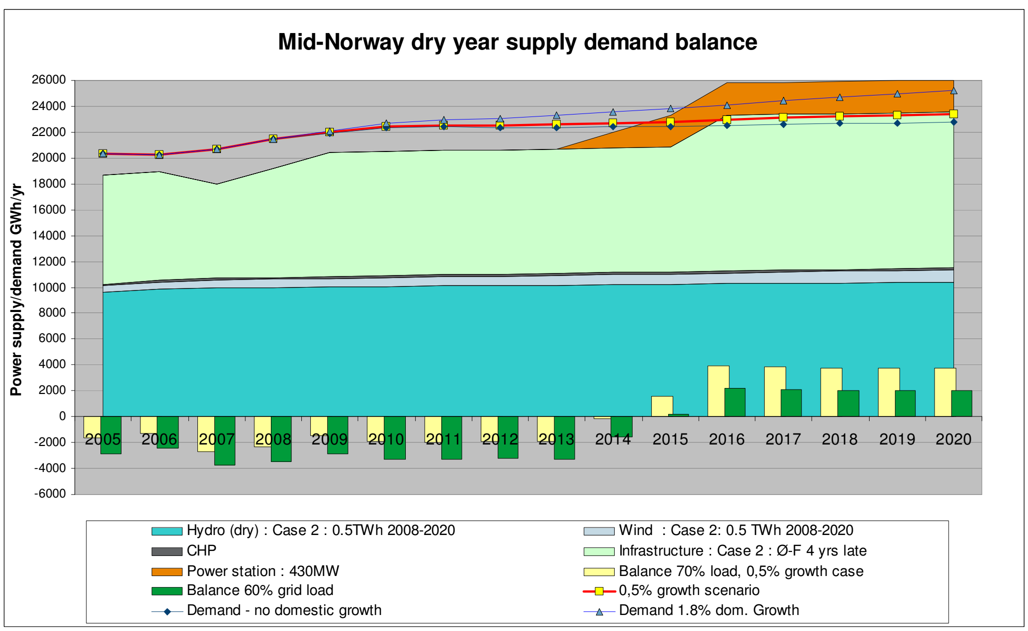
Scenario 1 : Reference case



Scenario 2 : As planned



Scenario 3 : Delays



Scenario 4 : More renewables

Appendix B1

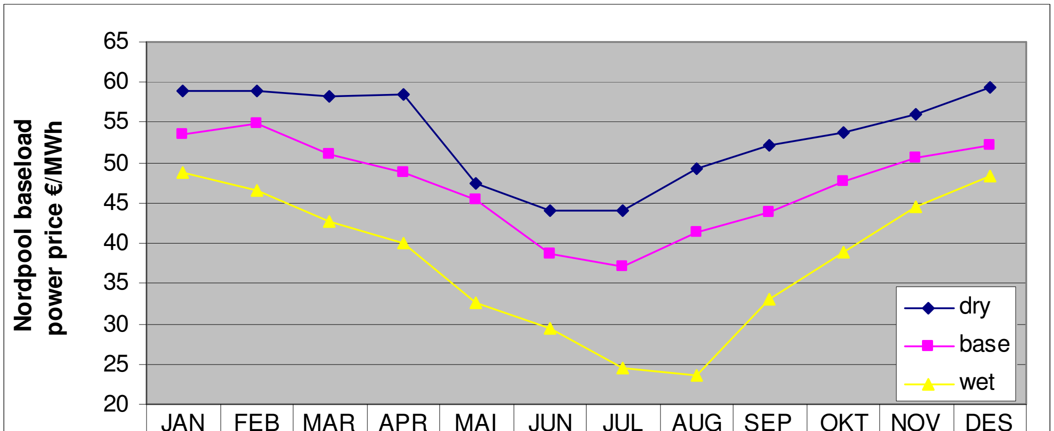
Economic Assumptions

Table 1. Power pricing – underlying evaluation assumptions

2011-2016 - Markedskraft modelling

2017-2030 – extrapolation based on industry open book data (CO_2) or flat pricing.

MK 30.10.2007	Oil, Brent ($/fat)			Gas*, TTF (€/MWh)			Coal Oct 2007 CIF ARA ($/ton)			CO2 (€/ton)			Share of free CO2-quotas		€/$ Oct 2007
Year	*Low*	*Base*	*High*	*Low*	*Base*	*High*	*Low*	*Base*	*High*	*Low*	*Base*	*High*	*Base*	*High*	
2011	45	65	75	16	21	25	60	85	120	12	24	33	80	80	1,42
2012	40	63	75	16	20	24	55	82	110	12	25	34	80	80	1,42
2013	35	62	75	16	20	24	55	80	100	13	26	35	60	0	1,42
2014	35	61	75	16	20	24	55	78	90	13	26	36	40	0	1,42
2015	35	60	75	16	20	24	55	76	88	14	27	37	35	0	1,42
2016	35	59	75	16	20	24	55	74	86	14	27	38	30	0	1,42
2017				16	20	24	55	70	85	14	28	39	20	0	1,42
2018				16	20	24	55	70	85	14	28	40	15	0	1,42
2019				16	20	24	55	70	85	14	29	42	10	0	1,42
2020				16	20	24	55	70	85	14	29	43	5	0	1,42
2021				16	20	24	55	70	85	14	30	44	0	0	1,42
2022				16	20	24	55	70	85	14	30	45	0	0	1,42
2023				16	20	24	55	70	85	14	30	46	0	0	1,42
2024				16	20	24	55	70	85	14	30	47	0	0	1,42
2025				16	20	24	55	70	85	14	30	48	0	0	1,42
2026				16	20	24	55	70	85	14	30	49	0	0	1,42
2027				16	20	24	55	70	85	14	30	50	0	0	1,42
2028				16	20	24	55	70	85	14	30	50	0	0	1,42
2029				16	20	24	55	70	85	14	30	50	0	0	1,42
2030				16	20	24	55	70	85	14	30	50	0	0	1,42



	JAN	FEB	MAR	APR	MAI	JUN	JUL	AUG	SEP	OKT	NOV	DES
dry	58,9	59,0	58,4	58,4	47,5	44,2	44,0	49,2	52,1	53,8	56,0	59,4
base	53,4	54,9	51,0	48,8	45,5	38,6	37,1	41,3	43,8	47,7	50,6	52,2
wet	48,7	46,6	42,8	39,9	32,5	29,5	24,5	23,5	33,1	38,8	44,4	48,4

Figure 1. Seasonal variation – Base fuel price scenario

Source : Markedskraft / Shell analysis

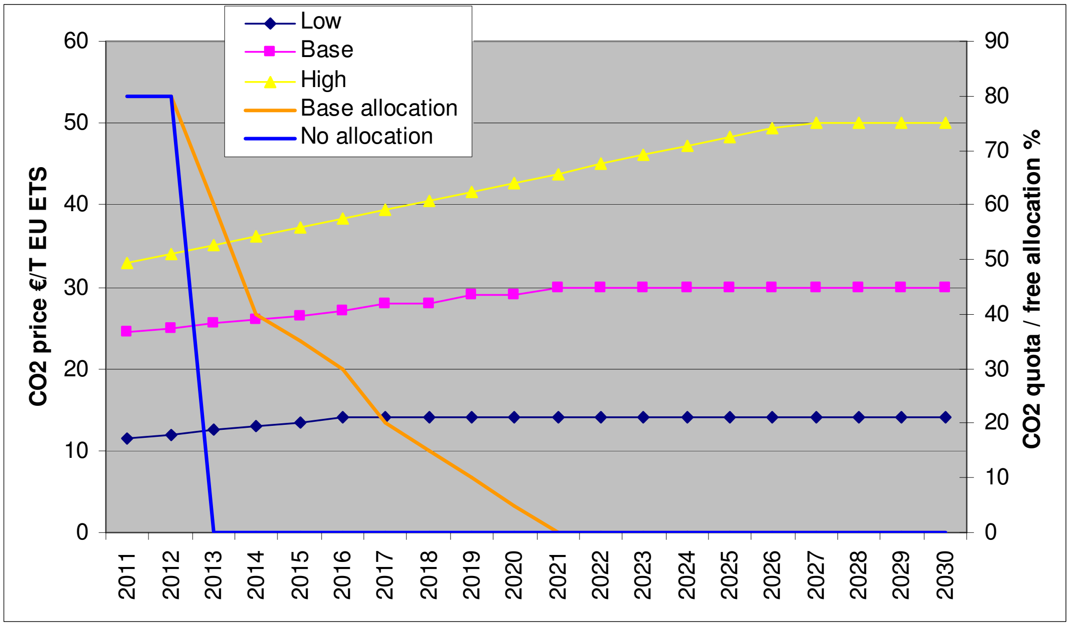


Figure 2. CO_2 cost €/Ton and free-allocation assumptions

Source : Markedskraft / other public domain

Appendix C1

Outline plot plan 430 MW power plant with carbon capture incorporated at Nyhamna

Appendix C2 Cost data (RT2008)

860MW 838,3 MW

CAPEX (MUSD)	Total	2010	2011	2012	2013
Power Plant	**1684**	205	321	653	506
Carbon Capture Plant	**1371**	175	260	527	409
Pipeline - 150km	**825**	0	159	328	337
Storage Wells	**176**	0	0	87	89

OPEX (MUSD / yr)		
Power Plant	**10,4**	Fixed
	19,2	Variable Non Fuel
Carbon Capture Plant	**17,4**	Fixed
	8,0	Variable Non Energy
Pipeline	**8,3**	1.5% of Capex
Storage Wells	**5,8**	5% of Capex

430MW 417,3 MW

CAPEX (MUSD)	Total	2010	2011	2012	2013
Power Plant	**869**	113	165	333	259
Carbon Capture Plant	**861**	112	163	330	256
Pipeline - 150km	**709**	0	137	282	290
Storage Wells	**176**	0	0	87	89

OPEX (MUSD / yr)		
Power Plant	**5,2**	Fixed
	9,6	Variable Non Fuel
Carbon Capture Plant	**10,4**	Fixed
	4,0	Variable Non Energy
Pipeline	**10,2**	1.5% of Capex
Storage Wells	**5,8**	5% of Capex

200MW case (actual plant is 253 MW installed capacity)

CAPEX (MUSD)	Total	2010	2011	2012	2013
Power Plant	**541**	67	103	209	162
Carbon Capture Plant	**549**	68	104	212	164
Pipeline - 150km	**633**	0	122	251	259
Storage Wells	**96**	0	0	47	49

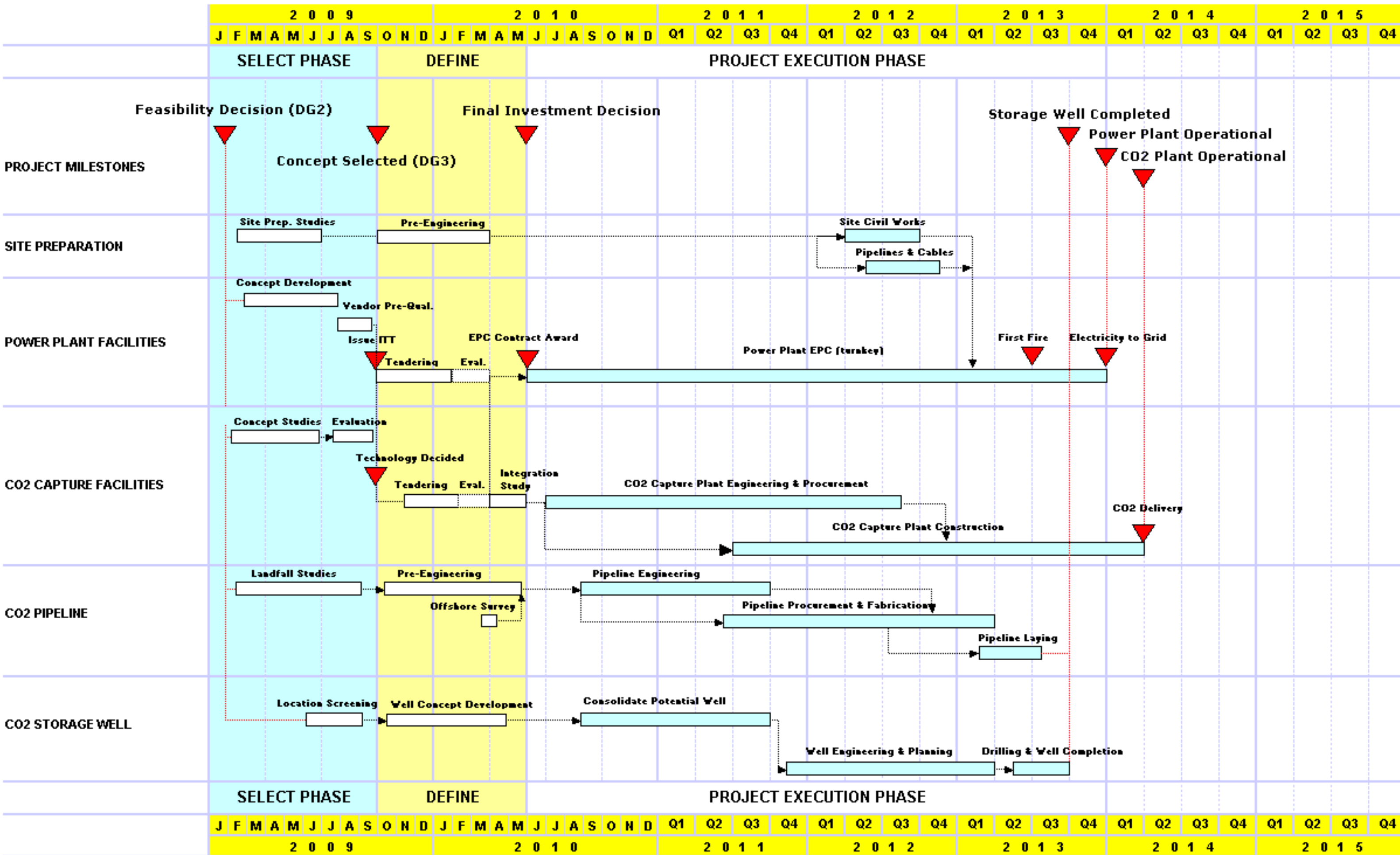
OPEX (MUSD / yr)		
Power Plant	**2,4**	Fixed
	4,5	Variable Non Fuel
Carbon Capture Plant	**5,8**	Fixed
	2,4	Variable Non Energy
Pipeline	**6,3**	1.5% of Capex
Storage Wells	**3,2**	5% of Capex

50MW case (actual plant is 67,5 MW installed capacity)

CAPEX (MUSD)	Total	2010	2011	2012	2013
Power Plant	**236**	33	44	89	69
Carbon Capture Plant	**286**	38	54	109	85
Pipeline - 225km	**633**	0	122	251	259
Storage Wells	**96**	0	0	47	49

OPEX (MUSD / yr)		
Power Plant	**0,6**	Fixed
	1,1	Variable Non Fuel
Carbon Capture Plant	**2,8**	Fixed
	1,2	Variable Non Energy
Pipeline	**6,3**	1.5% of Capex
Storage Wells	**3,2**	5% of Capex

Appendix C3 Technical data – Project schedule



Shell Exploration & Production Europe				Preliminary Project Schedule		
	01 Angus Smith	08.05.2008	Helge Skjaeveland	Mid-Norway Power Study		
	00 Angus Smith	30.04.2008				
	Revision / By	Date	Approv'd	Report: NPCCS_MCS_03	Scope: 430mW power plant & CCS	Status: May 2008