# Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the $CO_2$ Capture Project

## Capture and Separation of Carbon Dioxide from Combustion Sources

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# Chapter 3

# ECONOMIC AND COST ANALYSIS FOR $CO_2$ CAPTURE COSTS IN THE $CO_2$ CAPTURE PROJECT SCENARIOS

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## ABSTRACT

A common economic model was developed to facilitate direct and transparent comparison of the technologies studied and selected by the CCP. The CEM team worked closely with the technology development teams to ensure accuracy. The CEM accounted for site-specific scenarios, comparative case analysis, significant non-capture facility costs, multi or byproduct output, technology comparison rather than project evaluation, and generic versus regional pricing. These factors were used along with single discount factors, pre-tax analysis, and emission taxes to ensure a fair comparison.

Each scenario was evaluated and compared exhaustively. For some technologies cost reductions above 50% on a $CO_2$-avoided basis are indicated. The European Refinery (UK) Scenario case yielded cost reductions up to 48% for an oxyfuel case. The Alaska (Distributed Gas Turbines) Scenario showed only 19% savings in a pre-combustion decarbonization case. The Norway scenario (new-build large-scale gas turbines) showed cost reductions of 54% for a best integrated technology case and of 60% for a precombustion decarbonization system with hydrogen membrane reformers. The Canada Scenario (IGCC) showed savings of 16% over a highly optimized baseline gasification process.

## INTRODUCTION

The Common Economic Model (CEM) Team's main objective has been to develop and apply a common set of approaches and methods in cost estimation and economic screening of $CO_2$-capture technologies in the CCP program. This chapter describes the applied methods, as well as the results from the estimation and screening of technologies studied in the program. Appendix A shows the initial objectives for the CEM Team.

The "Summary and Conclusions" section of this chapter summarizes main $CO_2$-cost results calculated for the evaluated technologies, scenario by scenario, and highlights key observations from this material.

The basic $CO_2$-costs results presented in this chapter cover the capture process up to a delivery point where the $CO_2$ can be further transported to storage locations. Transportation and storage costs are addressed through the sensitivity analyses. The "Technology Screening" section reviews briefly the main elements of the technology screening, estimation and evaluation program in CCP during the late 2000–early 2004 period, as seen from the CEMT point of view. The "Basic Cost Estimates" section summarizes the work leading up to the final CCP-estimates.

Lastly, in the "Economic Screening" section the unit $CO_2$-cost measures applied in the technology comparisons are outlined and discussed as the basis for the CEM. Finally, key technology cost and performance data underlying the $CO_2$-cost results, are summarized in tables and charts, including "best estimate" basic data as well as a range of sensitivities.

The attached appendices and references provide further back-up material.

## SUMMARY AND CONCLUSIONS

### *Approach*

The $CO_2$-capture technologies studied in CCP have been brought several steps forward through this program. For some of these $CO_2$-cost reductions of more than 50% are indicated compared to current baseline (BAT)-technologies. However, most technologies are still in a development phase, and will need more R&D-resources and testing to reach a commercial stage.

The reported costs and performance data reflect our current "best estimates" of cost levels and operational performance of the technologies at a point in time when they are believed to reach their mature state of development, enabling implementation into commercial applications. More specifically, the estimates reflect the expected realization phase cost and emission performance under future operations of the capture technologies integrated with different types of existing or new $CO_2$-emitting combustion plants, reflected by the defined CCP scenarios in the United Kingdom (UK), Alaska, Norway and Canada (Table 1).

TABLE 1
CCP-SCENARIOS

| **Scenario** | | **Fuel source** | **Uncontrolled $CO_2$-emissions** |
|---|---|---|---|
| UK refinery | Heaters and boilers in the existing UK Grangemouth refinery | Refinery fuel oil and gas | 2.6 million tonne/yr from target H&Bs |
| Alaska turbines | Small, powergen gas turbines in the existing Prudhoe Bay complex | Natural gas | 2.6 million tonne/yr |
| Norway gas power | New, non-built gas powergen plant (CCGT) on the Norwegian W-coast | Natural gas | 1.3 million tonne/yr |
| Canada coke gasifier | New, non-built coke gasification plant (IGCC) in W-Canada | Petroleum coke | 4.9 million tonne/yr |

The future "commerciality point in time" is uncertain and will vary across technologies, depending first of all on the technical challenges in each individual case, but also on the strength of external pressures from national/international government energy and climate policies, and other technology and market developments.

The tables and charts below summarize the evaluated economic performance of capture technologies scenario by scenario, measured in terms of cost per tonne of $CO_2$ captured or avoided compared to original, uncontrolled $CO_2$ emissions. The "capture cost" reflects the total cost per tonne of reduced "target" emissions, while the "avoided cost" also includes the indirect emissions inherent in the additional energy demand of the capture systems. In this chapter, "tonne" is used as the term for metric tonne (1000 kg).

The unit $CO_2$-costs are here established from the incremental capture system capex, opex and energy costs, but do not include any front-end R&D-costs, or back-end $CO_2$-transportation and storage costs. The last element is, however, addressed and included among the sensitivities reported in the "Basic Cost Estimate" and "Economic Screening" sections of this chapter.

The incorporated costs are furthermore estimated at "generic" and local, scenario specific sets of unit costs and rates for utilities, energy and labor supplies. Generic prices are partly established from current market price level observations, but should be interpreted as long term (10–25 years horizon) expected price levels. The applied generic energy prices are:

- natural gas: USD 3.0 mBtu
- electricity: 34 USD $MW^{-1}$ (corresponding to uncontrolled, CCGT-power generation cost)
- feed coke: USD 10 per tonne.

In addition to these, a set of unit costs and rates for various utilities and labor costs is used in the capex/opex estimation work, listed in Ref. [1]. The basic capital charge rate applied in the $CO_2$-cost calculations are set to 11%, corresponding to a pre-tax discount factor of 10% over a 25-year lifetime. Main $CO_2$-cost results are provided at the generic cost and price level, while local price results are included among the sensitivities ("Economic Screening" section).

The final $CO_2$-cost results reflect the underlying physical scopes and cost estimates of the integrated "Scenario-Capture Technology cases". A major challenge has been to calibrate the physical scopes and contents across the "cases" enabling a fair and consistent cost and economic comparison of capture technologies. The Norwegian and Canadian scenario-cases are regarded as well aligned at this stage, whereas varying physical contents of processing facilities/utilities and shifting fuel/feedstock assumptions, e.g. in the UK scenario (see below) imply that case comparisons include more than cost and performance of capture technologies alone. Some cases are synergy concepts combining outcomes from earlier studies (e.g. the BIT-concept in the Norwegian scenario), and have thus not been through longer term evaluations as other technologies.

Based on the above approaches and comments, the resulting $CO_2$-costs are summarized below, scenario by scenario.

***UK Scenario***

The selected heaters and boilers are assumed to deliver a fixed amount of energy (heat and steam) to serve the refinery complex, corresponding to a certain fired duty level, assumed for all scenario–technology (S–T) cases.

The energy and utility demands of the capture systems are partly generated on-site, partly supplied through imports from external sources. Some technology cases, e.g. include new-built on-site power generating plants varying from 20–30 to 100–500 MW in size. The economics of these cases (e.g. the Oxyfuel-ASU and -ITM), thus include the full cost (capex&opex) of the power plants as well as large corresponding fuel gas and excess power export streams, in addition to the primary capture processing facilities, and the systems collecting $CO_2$ from the distributed emission sources. The effective $CO_2$-debits in the Oxyfuel cases correspond, however, to the $CO_2$-content in the net energy needs of the cases ($CO_2$ imported through the fuel gas, minus $CO_2$ exported through the excess power). With these variations in coverage of physical facilities and energy streams across the scenario-cases, one should be careful when comparing the $CO_2$-cost results, since these do not necessarily demonstrate performance of the various capture technologies per se.

The break-down of the $CO_2$-avoided costs shown in Table 2 are shown in Figure 1.

The above calculations indicate a Baseline avoided cost of USD 78 per tonne, whereas two of the pre-combustion cases and the Oxyfuel cases demonstrate costs of USD 40–50 per tonne. As described above, these cases are highly energy price sensitive due to the large energy import and export streams. By alternatively using the fuel gas and power prices applied by the Oxyfuel technology provider of USD 3.21/mBtu and USD 0.028 kW $h^{-1}$, the net value of energy import/export of the –ITM case (illustrated in Figure 1) is nearly neutralized. The resulting $CO_2$-costs are given in Table 3.

The break-down of the $CO_2$-avoided costs above are shown in Figure 2.

***Alaska Scenario***

The system of the 11 "target" gas turbines are assumed to deliver a fixed amount of energy (358 MW) to serve the existing offshore and onshore operations at Prudhoe Bay. When new facilities are planned or built on the North Slope, extraordinary construction and operating costs will be imposed, due to the remote location far from normal infrastructure, the weather and ambient conditions. On the other side, local energy is cheap, reflecting its "stranded" value, and are set to zero level in these evaluations. Basic results are, however, provided at a "generic" level, here implying that the physical scope of the technology cases including all necessary facilities are costed from the generic set of unit costs and rates referred in Ref. [1], and at the generic set of energy prices cited above.

TABLE 2
UK SCENARIO—KEY DATA AND $CO_2$-COST RESULTS (GENERIC)

| | | **Output; (fired duty) MW** | **Incremental capture system capex[a] MUSD** | **$CO_2$ captured; million tonne/yr[b]** | **$CO_2$ avoided; million tonne/yr[b]** | **$CO_2$-capture cost** | | **$CO_2$-avoided cost** | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | **USD/tonne $CO_2$** | **% change rel. to BL** | **USD per tonne $CO_2$** | **% change rel. to BL** |
| Post-combustion | Baseline (BL) amine MEA | 1351 | 362 | 2.19 | 1.55 | 55.3 | 0% | **78.1** | 0% |
| Pre-combustion | Membrane water gas shift w/DOE-membrane (MWGS/DOE) | 1351 | 520 | 2.19 | 1.54 | 59.8 | 8% | **84.9** | 9% |
| | Membrane water gas shift GRACE&DOE-membrane (MWGS/DOE) | 1351 | 214 | 1.99 | 1.50 | 36.4 | −34% | **48.1** | −38% |
| | Membrane water gas shift GRACE & Pd-membrane (MWGS/Grace) | 1351 | 251 | 1.99 | 1.50 | 39.6 | −28% | **52.4** | −33% |
| Oxy fuel | H&Bs w/fluegas recycle and ASU (FG-Rec ASU) | 1351 | 422 | 2.08 | 1.87 | 43.8 | −21% | **48.7** | −38% |
| | H&Bs w/fluegas recycle and ITM (FG-Rec ITM) | 1351 | 639 | 2.09 | 1.95 | 38.2 | −31% | **41.0** | −48% |

[a] Generic basis, excl. IDC.
[b] At 100% onstream level.

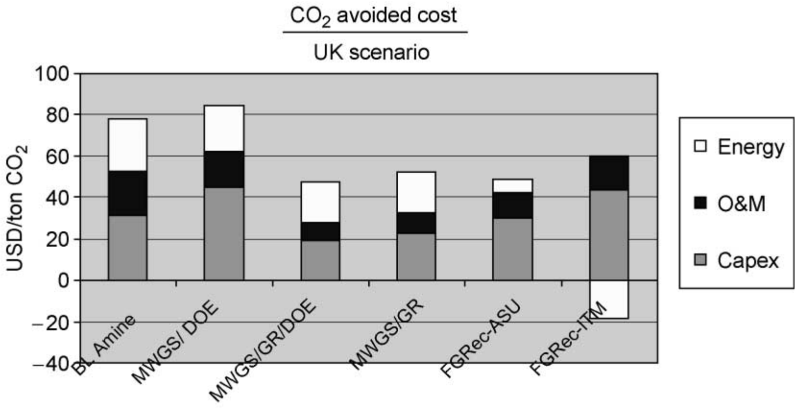


**Figure 1:** UK scenario—$CO_2$-avoided cost breakdown (generic).

TABLE 3
UK SCENARIO—KEY DATA AND $CO_2$-COST RESULTS (ALTERNATIVE FUEL GAS AND POWER PRICES)

| | | **$CO_2$-capture cost** | | **$CO_2$-avoided cost** | |
|---|---|---|---|---|---|
| | | **USD/tonne $CO_2$** | **% change rel. to BL** | **USD/tonne $CO_2$** | **% change rel. to BL** |
| Post-combustion | Baseline (BL) amine MEA | 56.6 | 0% | **79.8** | 0% |
| Pre-combustion | Membrane water gas shift w/DOE-membrane (MWGS/DOE) | 62.4 | 10% | **88.5** | 11% |
| | Membrane water gas shift GRACE& DOE-membrane (MWGS/Grace/DOE) | 37.4 | −34% | **49.4** | −38% |
| | Membrane water gas shift GRACE & Pd-membrane (MWGS/Grace) | 40.7 | −28% | **53.8** | −33% |
| Oxy fuel | H&Bs w/flue gas recycle and ASU (FG-Rec ASU) | 44.6 | −21% | **49.6** | −38% |
| | H&Bs w/flue gas recycle and ITM (FG-Rec ITM) | 53.1 | −6% | **56.9** | −29% |

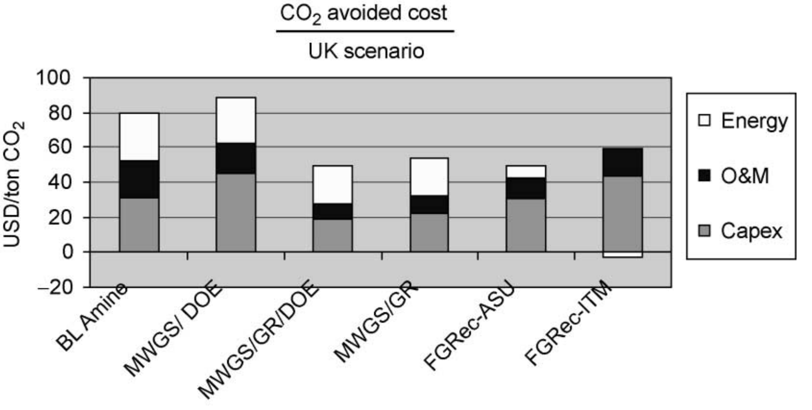


**Figure 2:** UK scenario—$CO_2$-avoided cost breakdown (alternative fuel gas and power prices).

In the capture technology cases included in Table 4, the Baseline case is exploiting excess steam to export 18 MW of power, while the two advanced pre-combustion cases assume that additional energy (fuel gas) is supplied through imports. The $CO_2$-costs (Table 4) are reported for the baseline and advanced cases at generic capex/opex costs and energy price levels.

TABLE 4
ALASKA SCENARIO—KEY DATA AND $CO_2$-COST RESULTS (GENERIC)

| | | Output; MW | Incremental capture system capex[a] MUSD | $CO_2$ captured; million tonne/yr[b] | $CO_2$ avoided; million tonne/yr[b] | $CO_2$-capture cost | | $CO_2$-avoided cost | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | USD/ tonne $CO_2$ | % change rel. to BL | USD/ tonne $CO_2$ | % change rel. to BL |
| Post-combustion | Baseline (BL) amine MEA | 358 | 1012 | 1.90 | 1.96 | 90.9 | 0% | **88.2** | 0% |
| Pre-combustion | Very large scale autothermal reformer (VLS-ATR) | 358 | 713 | 2.88 | 2.24 | 59.0 | − 35% | **76.0** | − 14% |
| | Sorption enhanced water gas shift (SEWGS) | 358 | 771 | 2.50 | 2.10 | 60.5 | − 33% | **71.8** | − 19% |

[a] Generic basis, excl. IDC.
[b] At 100% onstream level.

The calculations show avoided costs between USD 70 and 90 per tonne. Based on local priced cost estimates and free energy, avoided costs increase to nearly USD 130 per tonne for the baseline and to USD 80–85 per tonne for the advanced technology cases. The break-down of the generic $CO_2$ avoided costs are shown in Figure 3.

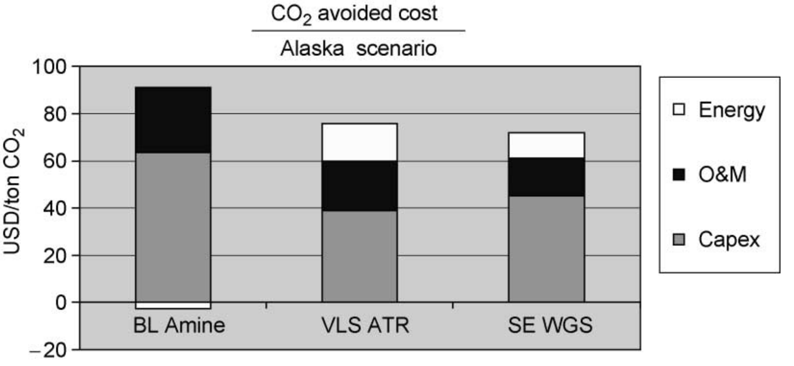


**Figure 3:** Alaska scenario—$CO_2$-avoided cost breakdown (generic).

***Norway Scenario***
The Norwegian scenario is represented by a new (currently non-built) gas-fired power plant (CCGT 400 MW) on the Western coast where fuel gas can be supplied from offshore reservoirs, and captured $CO_2$ can be returned and stored in aquifers or supplied to oil fields for EOR applications.

The evaluated capture technologies cover a range of maturity stages, from the further optimized post-combustion solutions to the future pre-combustion concepts. Key data and calculated $CO_2$-costs are given in Table 5.

The results (Table 5) indicate significant cost reduction potentials both within the near term and longer term available options:

- $CO_2$-costs of existing technologies may be reduced by 30–40% by value-engineering and design optimization (referring to the Nexant studies in Chapter 6 of this volume);
- by combining these findings with the MHI-solvent performance, $CO_2$-cost reduction potentials above 50% is indicated for the "BIT"-concept;
- an even larger cost reduction potential is indicated for the future pre-combustion HMR-technology.

The large reduction potentials above have to be confirmed through further development and verification work. The $CO_2$-avoided cost break-down is shown in Figure 4.

The cost of electricity generated by the various plants is a relevant economic measure in evaluation of power plant investment projects. The power generation costs for the various options are listed in Figure 5 with and without anticipated future $CO_2$-emission costs (emission taxes or emission trading quota prices).

The Baseline power generation cost is calculated at USD 34 and 42 MW $h^{-1}$ pre- and post the $CO_2$-emission costs, respectively. Figure 5 demonstrates how these power generation costs increase when including the various capture systems.

These calculations show that current capture (baseline) technology imposes a power price add-on of USD 19 MW $h^{-1}$, before emission costs, and reduced to USD 13 MW $h^{-1}$ under the assumed $CO_2$-cost. In local Norwegian currency the corresponding price add-ons are NOK 151 MW $h^{-}$ and NOK 102 MW $h^{-}$, respectively.

The lower-cost options impose, as shown, lower add-ons to the power price. The HMR-concept adds USD 9 MW $h^{-1}$ pre-tax, and merely USD 1–2 MW $h^{-1}$ including the assumed $CO_2$-emission cost. This corresponds in local currency, to 72 and 13 NOK/MWh increased power generation price, respectively.

TABLE 5
NORWAY SCENARIO—KEY DATA AND $CO_2$-COST RESULTS (GENERIC)

| | | Output; MW | Incremental capture system capex[a] MUSD | $CO_2$ captured; million tonne/yr[b] | $CO_2$ avoided; million tonne/yr[b] | $CO_2$-capture cost | | $CO_2$-avoided cost | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | USD/tonne $CO_2$ | % change rel. to BL | USD/tonne $CO_2$ | % change rel. to BL |
| Post-combustion | Baseline (BL) amine MEA | 323 | 129 | 1.09 | 0.87 | 49.0 | 0% | **61.6** | 0% |
| | Nexant BL design-basis | 322 | 134 | 1.09 | 0.87 | 47.6 | −3% | **60.0** | −3% |
| | Nexant BL design-"low" | 332 | 82 | 1.09 | 0.90 | 36.8 | −25% | **44.7** | −27% |
| | Nexant BL design-"integrated" | 345 | 61 | 1.09 | 0.94 | 30.2 | −38% | **35.1** | −43% |
| | MHI-Kværner; membrane contactor /KS1 | 335 | 127 | 1.09 | 0.91 | 39.5 | −19% | **47.5** | −23% |
| | BIT; best integrated concept; Nexant Integr. and MHI-KS1 | 357 | 69 | 1.09 | 0.98 | 25.3 | −48% | **28.2** | −54% |
| Pre-combustion | Hydrogen membrane reformer (HMR) | 361 | 98 | 1.27 | 1.17 | 22.5 | −54% | **24.4** | −60% |
| | Sorption enhanced water gas shift (SEWGS-O2ATR) | 360 | 150 | 1.28 | 1.02 | 34.1 | −30% | **42.7** | −31% |
| | Sorption enhanced water gas shift (SEWGS-Air ATR) | 424 | 178 | 1.47 | 1.21 | 28.2 | −42% | **34.4** | −44% |

[a] Generic basis, excl. IDC.
[b] At 100% onstream level.

The closer the added power price comes to zero (either by reducing technology costs or increased emission cost expectations), the closer gets also the profitability of power plant project including capture systems the uncontrolled power plant projects.

***Canada Scenario***

A planned coke gasification IGCC-plant generating power, hydrogen and steam is the Canadian scenario. For $CO_2$-calculation purposes the three output streams are measured as a combined output

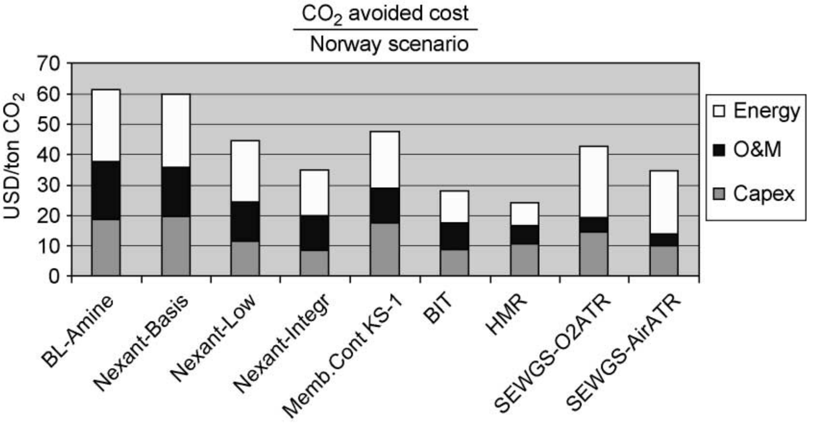


**Figure 4:** Norway scenario—$CO_2$-avoided cost breakdown (generic).

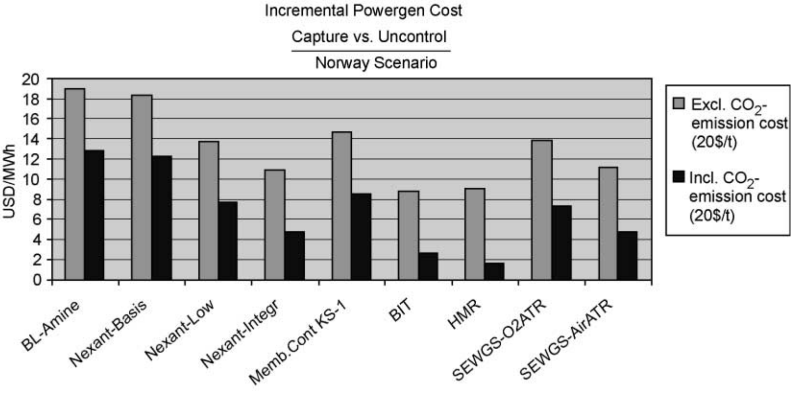


**Figure 5:** Norway Scenario—Incremental powergeneration cost (generic), including and excluding $CO_2$-emissions costs (USD 20 per ton).

as if all feed coke is used for power generation. The uncontrolled IGCC plant has a combined output of 588 MW. When pre-combustion capture systems are included, the power plant unit is increased to optimize the integrated concepts, leading to aggregate output levels of 699 and 734 MW, in the baseline and advanced ($CO_2$ LDSEP) options, respectively. Correspondingly, the feed coke and $CO_2$-generation volumes are increased in the capture cases relative to the uncontrolled case. The additional feed-coke volumes implicit also reflect a theoretical (proportional) uncontrolled power output, establishing the inherent power/efficiency losses, and in turn the avoided cost estimates, shown in Table 6 and Figure 6.

The low $CO_2$-capture and avoided costs shown here are mainly due to the fact that the Canadian scenario includes front-end coke gasification systems, and that the syngas production is included both in the uncontrolled and capture cases. The additional $CO_2$ capture units represent thus a smaller capex add-on per tonne $CO_2$ handled.

TABLE 6
CANADA SCENARIO—KEY DATA AND $CO_2$-COST RESULTS (GENERIC)

| | | Output; combined net power, hydrogen and steam; MW | Incremental capture system capex[a] MUSD | $CO_2$ captured; million tonne/yr[b] | $CO_2$ avoided; million tonne/yr[b] | $CO_2$-capture cost | | $CO_2$-avoided cost | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | USD/ tonne $CO_2$ | % change rel. to BL | USD/ tonne $CO_2$ | % change rel. to BL |
| Pre-combustion | Baseline (BL) IGCC with capture | 699 | 519 | 6.80 | 5.28 | 11.1 | 0% | **14.5** | 0% |
| | IGCC with advanced capture ($CO_2$LDSEP) | 734 | 516 | 6.44 | 5.22 | 9.9 | − 11% | **12.2** | − 16% |
| | IGCC with advanced capture ($CO_2$LDSEP) + 100% cost of "black box" | 734 | 689 | 6.44 | 5.22 | 14.6 | 31% | **18.0** | 25% |

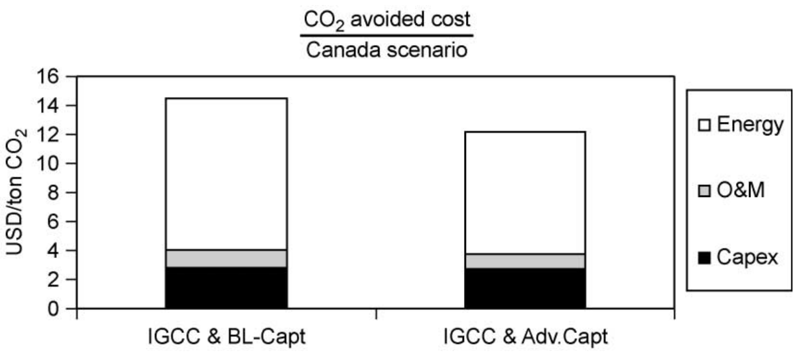


**Figure 6:** Canada scenario—$CO_2$-avoided cost breakdown (generic).

The $CO_2$-cost reduction potential by the advanced gasification technology ($CO_2$LDSEP) is calculated to 16%, at a "best estimate" basis. A cost sensitivity of 100% increase of the "black box" in this technology indicates that the reduction potential may disappear if technology development is unsuccessful.

***Discussion***

This chapter contains a significant number of estimates and calculation results. The general findings are summarized by discussing the following questions.

1. What relative and absolute $CO_2$-cost reductions are achieved?
2. How do the achieved $CO_2$-cost levels look from an external viewpoint?
3. What is the outlook for capture technology implementation from this perspective?

4. What can we indicate with respect to capture technology availability?
5. What further technology development and cost reduction potentials are possible?

*Addressing Question 1*: Figure 7 and Table 7 summarize $CO_2$-cost reduction ranges scenario by scenario without focusing on the specific technologies.

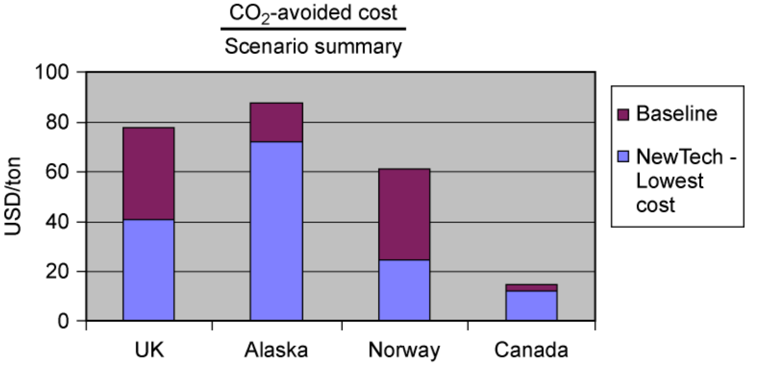


**Figure 7:** $CO_2$ avoided cost (generic)—CCP Scenario summary.

*Addressing Question 2*: $CO_2$-cost levels of capture projects are normally assessed by referring to long-term expectations of international $CO_2$- or Greenhouse Gas (GHG)-emission costs (emission taxes, quota prices, etc.) as part of global/regional climate gas policies. These are uncertain and may vary depending on time horizon, but the range USD 5–30 per tonne $CO_2$ seem to cover typical expectation levels.

*Addressing Question 3*: We can regard the upper part of this range (USD 20–30 per tonne $CO_2$) as a threshold price that $CO_2$-capture projects need to pass with their inherent $CO_2$-abatement cost, if projects are to be realized. Different $CO_2$-abatement cost terms and definitions may be applied (see discussion in the "Economic Screening" section). Both the "captured" and "avoided" $CO_2$-costs are thus given in the cost-range summary shown in Table 7.

*Addressing Question 4*: The technologies studied in this program cover a range of maturity levels. The Technical Teams have given some indications of the anticipated "breakthrough" points for some technologies, in terms of anticipated time before they can be available for real-life implementation.

*Addressing Question 5*: Further technology development and cost reduction is generally needed before technologies are technically and economically viable. In the last part of Table 7 rough estimates are made with respect to "necessary" improvements in order to achieve a $CO_2$-capture cost equal to a "threshold price" of USD 20 per tonne $CO_2$, reflecting the upper range of expected long term GHG-emission costs, as discussed above.

Table 7 summarizes achievements for the technologies demonstrating cost reductions, as reported here. Both cost reductions and absolute $CO_2$-costs vary within and across scenarios.

We furthermore observe that the absolute $CO_2$-cost figures are lower for the new/non-built plant scenarios (Norway and Canada) than for the existing plant scenarios (UK and Alaska). If this is a true and general result is hard to say, but it may seem intuitive, since the optimization potential for plant design and configuration is larger in new-built than retrofit situations.

The ratio between the capture cost (CC) and threshold $CO_2$-price (TP), applying the lowest CC in the group and a TP set to USD 20 per tonne, indicates the current realization potential from an economic decision point of view. For attractive projects, this ratio should be 1.0 or lower. The calculated ratios vary from 3.0

TABLE 7
SUMMARY $CO_2$-COST ACHIEVEMENTS (GENERIC BASIS)

| | | UK | Alaska | Norway | Canada |
|---|---|---|---|---|---|
| Relative $CO_2$-cost reductions | $CO_2$ capture cost | 8% incr.–34% red. | 34–35% red. | 19–54% red. | 11% red. |
| | $CO_2$ avoided cost | 9% incr.–48% red. | 14–19% red. | 23–60% red. | 16% red. |
| Absolute $CO_2$-cost | Captured | USD 36–60 per tonne | USD 59–91 per tonne | USD 23–49 per tonne | USD 10–11 per tonne |
| | Avoided | USD 41–85 per tonne | USD 72–88 per tonne | USD 24–62 per tonne | USD 12–15 per tonne |
| Project realization? | "Best case" capt. cost vs. threshold price ($20/t) | CC/TP: 1.8 | CC/TP: 3.0 | CC/TP: 1.1 | CC/TP: 0.5 |
| Capture technology availability | ("med-term" availability indicates maturity enabling real-life application within 1–5 yrs) | 4 techs incl., of which 1 available "med-term" | 2 techs incl., of which 0 available "med-term" | 7 techs incl., of which 4 available "med-term" | 2 techs incl., of which 1 available "med-term" |
| Further cost reductions (necessary to achieve CC = TP = $20/t, for "best case") | Overall power-/capture plant capex/ O&M-cost-level | Not discussed | Not discussed | 20–25% red. | Not discussed |
| | Capture system capex/O&M-cost-level | | | 60–65% red. | |

(Alaska) to 0.5 (Canada). Projects with ratios much higher than 1.0 will hardly be realized. However, projects with lower ratios may not be realized for other reasons. The CC/TP-ratio thus only reflects a necessary, but not a sufficient criterion for realization of capture projects.

For the Norway scenario (HMR-concept with the lowest CC) it is estimated that an overall reduction of power plant and capture system cost levels (total capex and opex, also affecting the uncontrolled case) of 20–25% will bring the calculated CC to USD 20 per tonne, or the CC/TP-ratio from 1.3 to 1.0. If cost reducing improvements are only focused on the HMR capture system alone to achieve the same result, these costs need a reduction of 60–65%.

The indications given above with respect to further developments of the actual capture technologies, are based on Technology Team assessments. In Figures 8 and 9, avoided $CO_2$-costs ("generic" basis) are plotted against a time horizon indicating development "breakthroughs" and potential implementation start for the Norway and UK scenarios.

## TECHNOLOGY SCREENING PROCESS

The basic CCP approach has been to apply and test the identified $CO_2$-capture technologies against a set of $CO_2$-emitting industrial plants, represented by the four application "scenarios" in Alaska, Canada, UK and Norway.

As benchmarks in developing and screening of new, non-mature capture technologies, two references are established: the uncontrolled emission/non-capture, and the "baseline" (or best available capture technology/BAT) "case" for each scenario. The physical capture and cost performance for all new capture

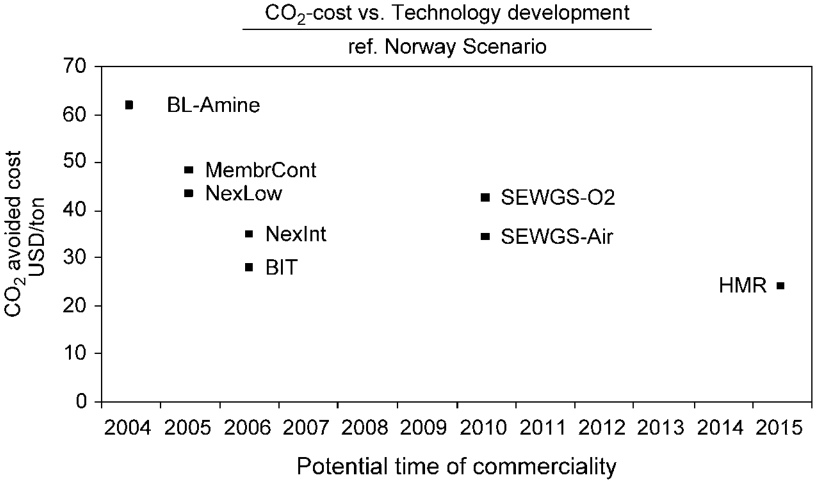


**Figure 8:** $CO_2$-cost reductions, technology development and time outlook for the Norway Scenario.

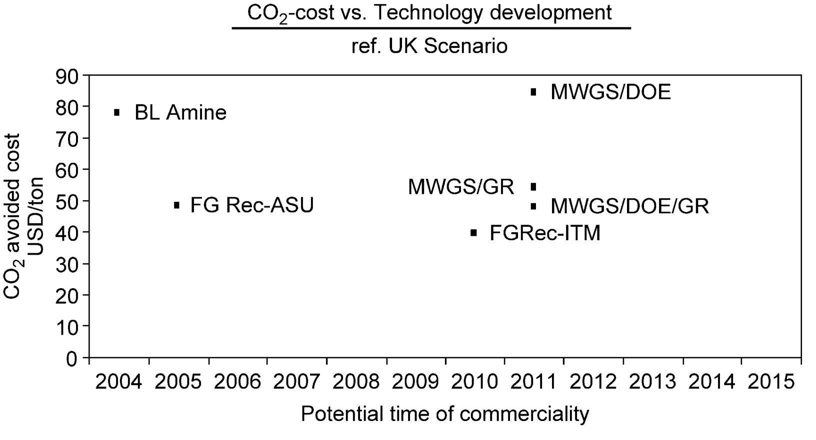


**Figure 9:** $CO_2$-cost reductions, technology development and time outlook for the UK Scenario.

technologies are measured against these references to establish the cost of $CO_2$-removal for the various technology options.

***Early Screening 2000–2001***

During the initial phase of CCP in 2000–2001, more than 50 different capture technologies or variants were listed as potential candidates for further development and evaluation. Of these, the most scenario-relevant and promising candidates were qualitatively identified in order to focus CCP efforts on the most attractive options. The early focus was to identify technologies with an expected technical and commercial development horizon of 5–10 years, i.e. potentially relevant for the 1st Kyoto protocol compliance period. During winter/spring 2001, CCP did a qualitative/semi-quantitative screening, which reduced the number of S–T combinations to approximately 25.

***Development and Estimation Work Programs***

From this point, various dedicated technology development and evaluation activities were initiated during 2001–2002, such as the:

- CCP Technical Teams contracting of a number of individual capture technology development studies and projects with external Technology Providers
- Post-Combustion Team's contracting of the "Baseline" reference studies for the UK and Alaska scenarios
- CEM Team's outlining of the "Common Cost Estimation" concept for integrated and consistent cost estimation of total S–T "cases"
- CEM Team's outlining of a "Common Economic Model" for consistent calculation and comparison of cost of $CO_2$-capture across Technology options
- Forming of an internal "Task Force" with members from the CCP Teams to establish an early picture of capture performance and cost reduction for the identified capture technologies

***Baseline Studies 2002***

The technical design and cost estimation work for the Baseline capture technology integrated with the UK and Alaska scenarios, were contracted to Fluor Daniel based on their post-combustion/flue-gas amine-scrubber technology. Fluor has done similar work for a Gas Power plant earlier (1998), providing the basis for the current Norwegian scenario. Later, they also carried out "uncontrolled" and "baseline" studies for the Canadian scenario (2003). Key deliveries from these studies are S–T integrated technical design and cost estimates (capex at local prices). These outputs are in turn an important reference for physical scoping, calibration and cost estimation of other new capture technologies.

***Task Force 2002***

External Technology Provider (TP)-studies, contracted by the CCP Technical Teams during 2001–2002, continued through most of the three-year program. At the end, the TP studies provide technical designs and cost estimates for their particular capture units or -technologies. According to the CCP-approach, all new capture technologies are implemented into the scenario context and include costs of all integration activities, energy/utility supplies, transportation/logistics, various site costs, etc.

A CCP-internal Task Force (TF) with members from the Capture Teams, the CEM-Team plus an external Cost Estimator consultant, was set up late 2001 to establish an early picture of capture performance and cost reduction for the identified capture technologies.

A list of the most relevant S–T "cases" from the S–T matrix was established for the task force work, starting early 2002. The Task Force carried out the following sequence of activity in their work:

- each of the selected S–T cases was technically described, outlined and documented by a "responsible process engineer" through flow diagrams, equipment lists, mass/energy/heat balances and $CO_2$-capture/emission volumes
- general scenario information and data were provided by the respective "scenario owner"
- through a close interaction between process engineer, scenario owner and cost estimator, the physical scope and boundaries were established for each S–T case with respect to included/not-included functions, as well as sizing and capacities of incorporated units
- with respect to utility supplies necessary capex–opex tradeoffs were made scenario by scenario to quantify supplies of the various demands and needs
- when the physical scope was established and calibrated across the S–T cases, a set of general unit costs and prices for relevant equipment, utilities and energy needs were applied to estimate capex and opex costs
- the price list was established at a generic US Gulf Coast level, i.e. the established cost estimates reflect the physical contents of the specific scenario locations, measured at USGC-prices.

During 2002, the Task Force worked through 15–20 S–T "cases" for the UK, Alaska and Norway scenarios, including baselines and new technology options and -variants. The results from this exercise are further documented in 2002 Task Force and CCP annual reports.

***Work Program 2003***

During 2001–2003, a S–T matrix of cases evolved dynamically. Many technologies were initially addressed and studied, several have been put away, and others have been adopted during the process, some as synergies of initial studies. The resulting S–T matrix is shown in Table 8.

The CCP program was completed during 2003 based on final Technology Providers study results and estimates. Several contributors provide cost estimates:

TABLE 8
FINAL SCENARIO–TECHNOLOGY MATRIX

| | **UK refinery heaters and boilers** | **Alaska turbines** | **Norway gas power plant** | **Canada coke gasifier** |
|---|---|---|---|---|
| Post-combustion | Baseline (BL) amine MEA | Baseline (BL) fluor amine MEA | Baseline (BL) fluor amine MEA | |
| | | | Nexant BL amine, basis | |
| | | | Nexant BL amine, low | |
| | | | Nexant BL amine, integrated | |
| | | | MHI-Kværner, amine-contactor | |
| | | | BIT-concept; Nexant BL amine integrated and MHI KS-1 solvent | |
| Pre-combustion | Membrane (DOE) water gas shift; (MWGS-DOE) | Very large scale autothermal reformer (VLS-ATR) | Hydrogen membrane reformer (HMR) | Baseline (BL) gasification |
| | Membrane (DOE) water gas shift; (MWGS-DOE-GRACE) | Sorption enhanced water gas shift (SEWGS) | Sorption enhanced water gas shift (SEWGS-$O_2$ ATR) | Advanced gasification ($CO_2$ LDSEP) |
| | MWGS/grace palladium membrane water gas shift; (MWGS-GRACE) | | Sorption enhanced water gas shift (SEWGS-Air ATR) | |
| OxyFuel | Heaters and boilers with flue gas recyle and ASU; (H&B w/FG-Rec. ASU) | | | |
| | Heaters and boilers with flue gas recyle and ionic transport membrane; (H&B w/FG-Rec. ITM) | | | |

- the external Technology Providers provide technical designs and cost estimates primarily for their capture technology units, and in some instances also for a fully integrated S–T “case”
- Fluor Daniel was contracted to establish a fully integrated technical outline and cost estimate for one selected new capture technology in each scenario
- two independent cost estimation consultants are engaged to update, calibrate, complete and document final CCP-cost estimates for the total S–T matrix of “cases”
- a group of senior CCP-company cost estimators (CERG) review and verify the total set of cost estimates across the S–T matrix.

The first two work programs delivered technical and cost estimate documentation for the individual technologies and “cases”. The last program, based on the first two programs, provided a total set of cost estimates (capex/opex) for all “cases”, cross-checked through the whole S–T matrix to enable fair and consistent technology comparison. Alignment of the scenarios, especially of the UK scenario, has not been straightforward since the different cases contain varying number of process units and operating features (large new power plants in some cases, or shifting fuel/feedstock assumptions). However, the Norwegian and Canadian scenarios are fairly well aligned (Tables 9 through 13 show the details for all four scenarios discussed here.

The final economic comparison of technologies is made using the CEM, which calculates unit $CO_2$-capture and avoided costs for all cases, based on the primary S–T cost estimates and energy-emission performance data.

## BASIC COST ESTIMATES

### *Individual Technology Providers*

The external technology providers presented technical designs and cost estimates primarily for their capture technology units and occasionally for a fully integrated S–T “case”. These results provided input to the total S–T estimation work described in below.

### *Fluor Daniel*

Fluor Daniel was contracted to establish a fully integrated technical design and cost estimate for a selected new pre-combustion technology options:

- UK: membrane water gas shift (MWGS)
- Norway: hydrogen membrane reformer (HMR)
- Alaska: sorption enhanced water gas shift (SEWGS)
- Canada: Advanced Gasification ($CO_2$LDSEP)

Fluor integrated the external Technology Provider results into the four scenarios, based on primary TP- and necessary scenario information. The selected S–T cases are evaluated by the same contractor as did the Baseline studies and is documented in other chapters of this volume. This should secure a consistent technical and estimate approach between Baselines and these new cases in the respective scenarios.

### *Final CCP Estimation*

Two independent Cost Estimation Consultants (CEs) are engaged to complete the total set of cost estimates for all “cases” in the S–T matrix. Their working approach is similar to the Task Force work of 2002, and their methods and assumptions are documented in a separate report (Eq. (2)). Their work efforts have varied across the S–T-cases. In some cases, they have established the cost estimates from scratch based on CCP-internal and Technology Provider information. In other cases, provided estimates are scope adjusted with respect to utilities, site costs, contingencies, etc. In these cases, opex estimates usually are established by the CEs. Furthermore, all estimates are transformed from locally priced costs to a set of estimates based on “generic” supply price levels.

***Cost Estimate Review***
The internal Cost Estimating Review Group (CERG) have reviewed all cost estimates produced by the CEs (and indirectly the TP- and Fluor-estimates), and their comments are incorporated in the final CE results. Figure 10 illustrates the CCP-cost estimation process.

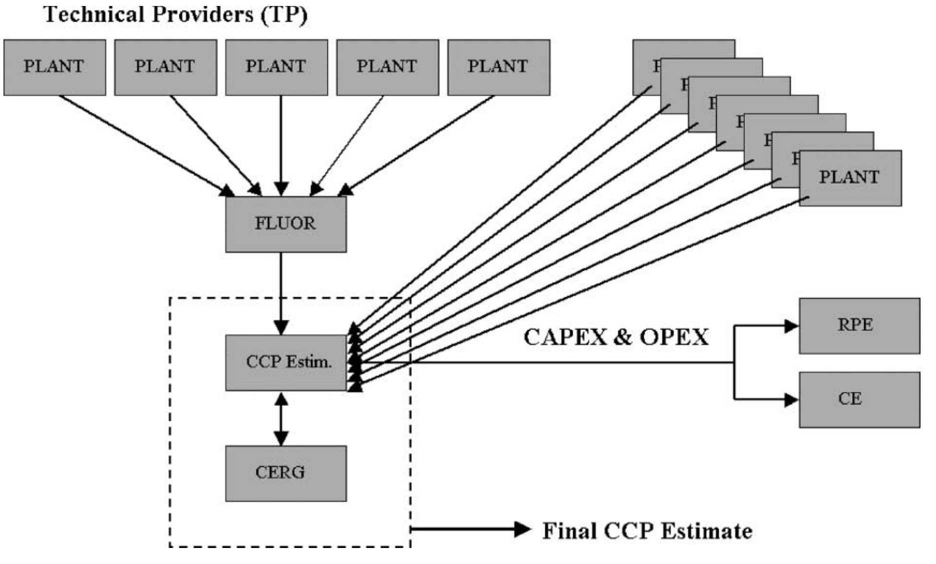


**Figure 10:** Overall CCP cost estimation process.

***Final S–T Cost Estimates***
The final integrated S–T CCP-cost estimates based on external and internal sources, showing breakdowns and estimate details are documented in separate report [1]. The key CCP estimates are, however, summarized below for each scenario, in millions of USD (2003).

TABLE 9
UK SCENARIO—INCREMENTAL CAPTURE PLANT CAPEX, O&M

| **Capture technology** | **"Generic cost"** | | **"Local cost"** | |
|---|---|---|---|---|
| | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** |
| Baseline (BL) amine | 362 | 30 | 424 | 33 |
| MWGS-DOE | 520 | 23 | 599 | 26 |
| MWGS-DOE/Grace | 214 | 12 | 250 | 14 |
| Pd-MWGS/Grace | 251 | 14 | 292 | 16 |
| H&B w/FG-recycle and ASU | 422 | 21 | 484 | 23 |
| H&B w/FG-recycle and ITM | 639 | 28 | 730 | 31 |

[a] Variable O&M at 90.4% onstream level.

TABLE 10
ALASKA SCENARIO—INCREMENTAL CAPTURE PLANT CAPEX, O&M AND ENERGY COSTS

| **Capture technology** | **"Generic cost"** | | **"Local cost"** | |
|---|---|---|---|---|
| | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** |
| Baseline (BL) amine | 1012 | 53 | 1474 | 71 |
| Very large scale auto thermal reformer (VLS-ATR) | 713 | 46 | 992 | 57 |
| Sorption enhanced water gas shift (SEWGS) | 771 | 34 | 1072 | 46 |

[a] Variable O&M at 98.5% onstream level.

TABLE 11
NORWAY SCENARIO—TOTAL BASIC AND CAPTURE PLANT CAPEX, O&M AND ENERGY COSTS

| **Capture technology** | **"Generic cost"** | | **"Local cost"** | |
|---|---|---|---|---|
| | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** | **Accum. capex (TIC)** | **Annual opex, ex. energy[a]** |
| Uncontrolled 400 MW CCGT | 284 | 13 | 333 | 15 |
| Baseline (BL) amine | 412 | 29 | 496 | 32 |
| Nexant BL design-basis | 418 | 26 | 506 | 30 |
| Nexant BL design-"low" | 366 | 24 | 439 | 27 |
| Nexant BL design-"integrated" | 345 | 24 | 413 | 26 |
| MHI-Kværner, amine-membrane contactor | 410 | 23 | 494 | 26 |
| "BIT" concept; Nexant integrated + MHI solvent | 352 | 21 | 421 | 24 |
| Hydrogen membrane reformer (HMR) | 382 | 20 | 453 | 22 |
| Sorption enhanced water gas shift (SEWGS-O2ATR) | 434 | 20 | 517 | 23 |
| Sorption enhanced water gas shift (SEWGS-AirATR) | 462 | 21 | 549 | 25 |

[a] Variable O&M at 95% onstream level.

### ***$CO_2$-Transportation and Storage Costs***

In addition to the above costs, the SMV team has established $CO_2$-transportation and storage costs based on scenario specific information on $CO_2$-volumes, pressures, composition, transportation distance from capture plant to the proposed storage site. It is assumed that the captured $CO_2$ is transported through dedicated new-built pipelines (i.e. no common infrastructure) to an offshore storage location where the $CO_2$ is injected into depleted oil reservoirs or underground aquifers. The capex and opex data is generated by using an external pipeline transport design and costing model (GEODISC).

TABLE 12
CANADA SCENARIO—TOTAL BASIC AND CAPTURE PLANT CAPEX, O&M AND ENERGY COSTS

| Capture technology | "Generic cost" | | "Local cost" | |
|---|---|---|---|---|
| | Accum. capex (TIC) | Annual opex, ex. energy[a] | Accum. capex (TIC) | Annual opex, ex. energy[a] |
| Uncontrolled case | 822 | 37 | 889 | 40 |
| Baseline (BL) IGCC gasification with capture | 1341 | 61 | 1448 | 66 |
| IGCC with adv. gasification ($CO_2$LDSEP) | 1338 | 60 | 1440 | 64 |
| IGCC with adv. gasification ($CO_2$LDSEP + 100% capex "blackbox") | 1511 | 67 | 1624 | 72 |

[a] Variable O&M at 91.3% onstream level.

TABLE 13
$CO_2$-TRANSPORTATION AND STORAGE KEY DATA AND COSTS (GENERIC COST)

| | UK | Alaska | Norway | Canada |
|---|---|---|---|---|
| $CO_2$-volume | 2.0 million tonne/yr | 2.2 million tonne/yr | 1.3 million tonne/yr | 6.3 million tonne/yr |
| $CO_2$ delivery / pipeline inlet pressure | 152 Bar | 140 Bar | 200 Bar | 221 Bar |
| Storage site | Depleted oil field (forties) | Depleted oil field (adjac. to turbine complex) | Offshore aquifer (Utsira) | Depleted oil field (Beaverhill lake) |
| Pipeline distance | 410 km | 0 km | 150 km | 400 km |
| Pipeline diameter | 14 in. | 4 in. | 10 in. | 24 in. |
| Reservoir depth | 2135 m | 1219 m | 900 m | 2652 m |
| Injection wells | 1 | 1 | 1 | 2 |
| Capex | USD 257.2 million | USD 0.8 million | USD 138.2 million | USD 191.5 million |
| Opex | USD 18.0 million/yr | USD 0.1 million/yr | USD 9.7 million/yr | USD 13.4 million/yr |

The $CO_2$ transportation and storage costs are not included in the basic $CO_2$ cost calculations, but are included as sensitivity. The potential value of EOR benefits by injecting $CO_2$ for tertiary oil recovery is also briefly addressed in the sensitivity studies.

## ECONOMIC SCREENING

### *$CO_2$-Costs*

The *cost of capturing* $CO_2$ emitted from the industrial plants defined by the CCP scenarios is the key measure of the absolute and relative economic performance of capture technologies in this program.

The basic approach in measuring the $CO_2$-cost is a differential comparison of capture vs. non-capture (uncontrolled) industrial plant outlines. This implies (a) to identify key operating and emission performance data for an uncontrolled plant, and (b) to establish the additional costs (investments, O&M, energy) and reduced emissions resulting from the capture system integrated in the plant.

The $CO_2$-cost is normally expressed in monetary terms per unit $CO_2$, e.g. USD/tonne $CO_2$. There are, however, different ways to formulate the $CO_2$-cost measure:

- as "capture cost", expressing the identified costs per tonne $CO_2$ directly captured from target plant emissions. This cost can be calculated either using annualized or discounted data, on a normalized plant output basis. In a fossil fuelled power plant, this $CO_2$ cost can be expressed by a differential capture vs. no-capture ratio between power generation costs (COE) and specific $CO_2$ emissions ($CO_2$SE):

$$\text{Capture cost} = -(\text{COE}_{\text{capture}} - \text{COE}_{\text{non-capture}})/(\text{CO}_2\text{SE}_{\text{direct, capture}} - \text{CO}_2\text{SE}_{\text{direct, non-capture}}) \qquad (1)$$

- as "avoided cost", expressing the same costs per tonne $CO_2$ captured minus non-captured $CO_2$ inherent in the additional energy demanded by the capture processing units, which is equivalent to requiring total capture costs normalized to same net plant output in both capture and non-capture situations. Since capture processes normally consume energy (gas or fossil based power), indirect $CO_2$-emission debits are generated. Thus, avoided $CO_2$ emissions are usually lower than captured $CO_2$, and avoided $CO_2$ costs are correspondingly higher than capture costs:

$$\begin{aligned}\text{Avoided cost} = -&(\text{COE}_{\text{capture}} - \text{COE}_{\text{non-capture}})/(\text{CO}_2\text{SE}_{\text{direct+indirect, capture}} \\ &- \text{CO}_2\text{SE}_{\text{direct, non-capture}})\end{aligned} \qquad (2)$$

  In some of our S–T cases, new power-generation plants are installed on-site to supply additional energy needs of the capture systems. These plants may generate excess power for export, and corresponding $CO_2$-credits are generated.
- as NPV-"equivalence", or "threshold $CO_2$ cost", expressing the $CO_2$ emission cost at which the total NPVs for competing capture and non-capture outlines of a project is equal, providing a measure directly relevant in project decisions:

$$\text{CO}_2\text{-threshold cost} = \frac{(\text{NPV}_{\text{pre-CO}_2-\text{ec}})_{\text{capture proj}} - (\text{NPV}_{\text{pre-CO}_2-\text{ec}})_{\text{non-capture proj.}}}{(\text{PV-CO}_2-\text{emiss.})_{\text{capture proj.}} - (\text{PV-CO}_2 - \text{emiss.})_{\text{non-capture proj.}}} \qquad (3)$$

This measure corresponds directly with the NPV-based investment decision criteria; implying that if the $CO_2$-threshold cost is lower than the expected $CO_2$-emission cost (ec), the capture project is more profitable than the non-capture project, and vice-versa.
Depending on nature and definition of projects and assumptions, the measures above may provide equal or non-equal $CO_2$-costs, normally at the same level of magnitude. In our studies, the "avoided cost" concept is selected as the main economic measure. Normally, these $CO_2$-cost measures are used to establish the state-of-the-art economic performance for available capture technologies mainly within the power generation industry, where relevant cost, energy and emission data normally are easily available. The CCP-program, however, has several features making the establishment of relevant data to a main challenge, as well as raising some methodical questions.

***Discussion***
First of all, CCP's focus is technology development and comparison, not dedicated project realization. Secondly, the site-specific scenario approach sets a real-life context, but at the same time involving several additional aspects affecting cost estimation and economic screening work, such as:

- additional plant and site functions and needs, influencing physical boundary settings and contents of cost estimates
- multi-/by-product delivery streams additional to primary (power) plant outputs
- establishment of market, tax and economic assumptions for the evaluation and screening work.

*Site-specific scenarios*
The "scenarios" established in the CCP-program represent a basic specification of the evaluation framework, setting the physical scopes and boundaries for the S–T-cases. This approach implies that technologies should only be compared within and not across scenarios.

*Comparative rather than single-case studies*
However, also within the scenarios, technologies are individually developed and evaluated by a number of different Technology Providers, based on mixed sets of scenario and technology assumptions. A main challenge has been to align physical contents and calibrate cost for each S–T case to enable fair comparison within scenarios. The physical scopes across the Norwegian and Canadian Technology cases are the best aligned scenarios from a comparative perspective.

*Non-capture facility costs are significant*
The capture technologies are being integrated into the various scenarios, together with a number of non-capture processing, utility and site facilities. The capture unit capex share of total capex estimates ranges from 20 to 60% across cases. The non-capture costs thus also have significant impacts on the final $CO_2$-costs.

*Multi-/by-product output*
In some scenarios and cases, the plants being studied deliver more than one output. Such outputs affect the standard $CO_2$-cost calculations described above. In some cases (e.g. Canada) the total output of power, hydrogen and steam is transformed into an aggregate MW-plant output. In the UK and Alaskan scenarios, the export of excess power is credited in terms of revenue in the $CO_2$-cost calculations. Similarly, the potential revenues from $CO_2$-sales to oilfield EOR-customers are treated in the same way as in the sensitivity exercises discussed in the "local price assumptions" section.

*Technology vs. project evaluation*
Economic project evaluation is typically demanded in decision processes when selecting between investment alternatives based on available technologies, and/or making final realization decisions on matured projects. A basic feature in traditional NPV-based project evaluation is to establish lifetime cash flows for the actual project based on expected (50/50)-level estimates of revenues and costs. This "best estimate" net cash flow is typically transformed to NPV-estimates, using risk-adjusted discount factors.

CCP investigates technologies, not specific projects, at both mature and non-mature states of development. This addresses several questions with respect to the relevance of traditional evaluation methods, e.g. regarding discount factors, expected level data, taxation, etc.

*Discount factor*
It is relevant to ask questions with respect to the discount factors when used in R&D-technology evaluations.

- Should we apply higher risk-adjusted rate of return (ROR) than normal in evaluating R&D-projects, since the benefits from these are more uncertain and undefined than matured realization projects?
- Should we apply lower RORs than for individual projects, since high rates often would kill new R&D-concepts and -ideas in the very start?
- Should project RORs be lowered since the potential outcome from R&D-efforts could serve not only one, but a number of future realization projects?
- Should we take the R&D-costs and -time into consideration?

- Could a relevant evaluating approach for R&D-decisions be decision tree-analyses, incorporating R&D-costs and schedules, potential R&D outcomes and -probabilities combined with reduced risk-adjustments of discount factors?

Many arguments can be put forward, and conclusions will depend on what questions we want to evaluate. In our studies, however, we have not brought these issues into the analysis. We have not included pre-realization R&D-time and costs (see Figure 11), but rather focused on “best estimate” analysis of the realization phase of capture technologies, at a real discount factor of 10%, and sensitivities at 7 and 13%.

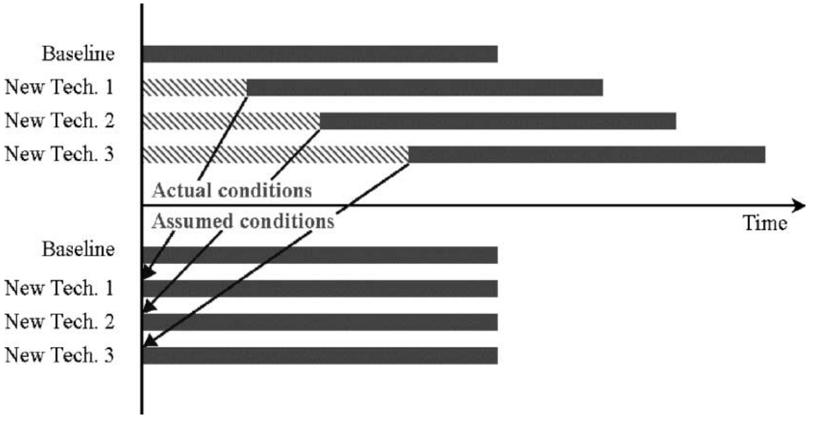


**Figure 11:** Simplified evaluation of technologies at different states of maturity.

*Expectation data*
Another issue closely related to this, is the question of how to handle the expected level-estimates in a quantitative screening of developing technologies.

As outlined above, the basis in standard project evaluation is expected-level estimates for all revenues and costs. In our program, where primary technology units are non-mature and not currently available, we need to establish future expectations of technology performance and costs given a certain (but unknown) forward R&D-process. How do we handle that? On the cost side, some would argue that non-developed technologies need higher contingency add-ons than mature technologies to establish expected level estimates. This may seem reasonable, but static, and possibly work as “show-stoppers”. On the other side, non-mature technologies may achieve far more on cost-reductions through active technology development, than available technologies. Can we adjust actual, non-mature state estimates by adapting “learning” or “technology development curves” to establish the future, expected commercial-state data? In our exercise it is assumed that technology cost and performance estimates reflect the commercial state estimates at some future point in time (that may differ across technologies).

*Pre-tax evaluation*
Our evaluation of un-mature technologies makes post-tax analysis less relevant compared to dedicated analysis of realization projects. Basically, we want our cost calculations to be influenced mainly by technical variables, and be as neutral with respect to shifting, non-technical and external conditions as possible. This exercise is thus entirely performed at pre-tax basis.

*Emission taxes*
The only tax elements involved (in some sensitivity evaluations) are emission taxes (both for $CO_2$, $NO_x$ and $SO_2$), reflecting future cost of emissions, and one of the main drivers for the whole CCP-program (see section "$CO_2$-/$NO_x$-/$SO_2$-Emission Costs—Market References" under Appendix A).

*Generic vs. regional pricing*
With respect to market data, we basically apply a set of generic unit prices and cost rates in order to provide results with broader relevance, than only for the specific scenario. We have, however, supplemented this approach with a set of locally priced capex/O&M and energy supplies, as sensitivities in cost estimation and economic evaluations.

***CEM-Model***
Based on the above principles an economic screening tool (CEM) was developed to compile key cost and emission data for the capture technology options and perform comparative $CO_2$-cost evaluations within each scenario.

Based on the capex and opex estimates and key performance data for each of the S–T cases on:

- physical energy (electricity, fuel gas, feed-coke) consumption
- $CO_2$ capture/emission volumes
- non-$CO_2$ ($NO_x$, $SO_2$)-emissions and shadow-prices
- plant onstream-factors
- discount factors, time-variables and capital charge factors

The model calculates the $CO_2$-capture and avoided costs as described in the "$CO_2$ Costs" section of this chapter. The section "$CO_2$-Cost Calculations Norway Baseline" under Appendix A demonstrates a numerical calculation example (Norway Baseline). The key price and economic assumptions used in economic screening of technologies are given in Table 14.

TABLE 14
KEY PRICE AND ECONOMIC ASSUMPTIONS

| Category | Specific | Units | Generic | UK | Alaska | Norway | Canada |
|---|---|---|---|---|---|---|---|
| Energy | Natural gas | USD/mBtu | 3.0 | 3.0 | 0.0 | 2.0 | 3.0 |
| | Electricity[a] | USD/MWh | 34 | 34 | 0 | 34 | 34 |
| | Coal/coke | USD/tonne | 30 | – | – | – | 0 |
| Emission costs (sensitivities) | $CO_2$ | USD/tonne | 20 | | | | |
| | $NO_x$ | USD/tonne | 2500 | | | | |
| | $SO_2$ | USD/tonne | 200 | | | | |
| Capital return requirement | Discount factor | Real rate | 10% | | | | |
| | Annual capital charge factor | | 11.02% for a 25 yr project lifetime | | | | |

[a] base case uncontr. CCGT-powergen-cost.

The generic price list is established, and partly based on current market price levels and observations, but should be interpreted as long-term (10–25 years horizon) expected price levels.

Generic and local prices differ mainly with respect to labor cost and productivities, and energy-prices, where the following assumptions are made:

- Alaskan power and gas prices are set to zero, reflecting their alternative, “stranded” value
- a reduced price of gas delivered to a power plant location on the Norwegian west-coast, reflecting the potentially avoided downstream processing and pipeline transportation costs
- the price of coke/coal in Canada is set to zero, reflecting its alternative local value.

***Economic Screening Data and Results***

This section presents tabulated details with respect to key input and result data from the economic screening work including basic and sensitivity data. All main observations and discussions are made in the previous chapters. However, a few issues addressed by sensitivity exercises below, should be noticed here.

*Local price assumptions*

As mentioned earlier, the generic price and unit cost assumptions are supplemented by a set of local, site-specific prices. These assumptions are simplified by relating these only to labor cost/productivities, referred in Eq. (1), and energy. Local capex and O&M-estimates are reported in the Final Scenario/Technology Cost Estimates section.

For energy pricing the following assumptions are made for sensitivity analysis (Table 14):

- Alaskan power and gas prices are set to zero, reflecting their alternative, “stranded” value
- a reduced price of gas delivered to a power plant location on the western coast of Norway, reflecting the potentially avoided downstream processing and pipeline transportation costs
- the price of coke in Canada is set to zero, reflecting its alternative, local value.

*Non-$CO_2$-emissions*

Non-$CO_2$ emission impacts from burning of fossil fuels are addressed in some of the $CO_2$-capture technology studies in the UK-scenario. As a sensitivity in reduced $NO_x$-/$SO_2$-emissions are credited in the $CO_2$-cost calculations based on the following emission costs (based on price observations from US emission trading markets, Figure 13.

- $NO_x$: USD 2500 per tonne
- $SO_2$: USD 200 per tonne

*$CO_2$-transportation, storage and EOR*

The cost impact of the “back-end” transportation and storage (T&S) part of the total $CO_2$-chain was tested. The first sensitivity includes the pure transportation and storage costs referred in Table 13, constant for all cases within each scenario. However, the avoided $CO_2$-cost impact differs when the same costs are divided on varying avoided $CO_2$-volumes:

- in the UK Baseline case the T&S-costs add USD 35 per tonne to the initial $CO_2$-avoided
- in Alaska where the captured $CO_2$ can be injected directly by existing well systems, there are hardly any additional costs incurring
- in the Norwegian scenario an additional costs of USD 32 per tonne are generated by the given S&T-costs
- in the Canadian scenario USD 7–8 per tonne is added to the unit $CO_2$-cost, due to the large $CO_2$-volumes (Table 14).

TABLE 15
UK KEY COST, PERFORMANCE INPUT DATA AND RESULTS—GENERIC PRICES

| **Summary economics UK refinery heaters and boilers** | **Units** | **Uncon-trolled** | **Baseline post-comb BL amine flour** | **NewTech pre-comb MWGS/DOE Eltron/SOF Co/Fluor** | **NewTech pre-comb MWGS/ GR/DOE BP** | **NewTech pre-comb MW/GS/ GR BP** | **NewTech oxyfuel FGRec-ASU APCI** | **NewTech oxyfuel FGRec-ITM APCI** |
|---|---|---|---|---|---|---|---|---|
| *Plant outputs* | | | | | | | | |
| Fired duty of select heaters and boilers | MW | 1351 | 1351 | 1351 | 1351 | 1351 | 1351 | 1351 |
| Overall onstream factor | % | 90.4 | 90.4 | 90.4 | 90.4 | 90.4 | 90.4 | 90.4 |
| *Scenario–technology costs* | | | | | | | | |
| Total capex, excl. IDC (CCGT- and capture plants) | MUSD | 0 | 362 | 520 | 214 | 251 | 422 | 639 |
| Specific total capex (per MW net power output) | | | | | | | | |
| Capture systems capex | MUSD | | 362 | 520 | 214 | 251 | 422 | 639 |
| Specific capture systems capex (per annual tonne $CO_2$ avoided) | USD/tonne | | 233 | 337 | 143 | 167 | 225 | 328 |
| Specific capture systems capex (per annual tonne $CO_2$ captured) | USD/tonne | | 165 | 237 | 108 | 126 | 203 | 306 |
| Total O&M, excl. energy | MUSD/yr | 0 | 30 | 23 | 12 | 14 | 21 | 28 |
| Total O&M, incl. energy | MUSD/yr | 0 | 66 | 55 | 39 | 41 | 31 | −5 |
| *Energy consumption (net increase capture system)* | | | | | | | | |
| Fuel gas, LHV[a] | TBtu/yr | 0.0 | 11.8 | 14.5 | 9.0 | 9.0 | 4.5 | 29.4 |
| Electricity/steam[a] | MW | 0 | 0 | −42 | 0 | 0 | −11 | −446 |
| Coke[a] | Million tonne/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

(*continued*)

TABLE 15
CONTINUED

| **Summary economics UK refinery heaters and boilers** | **Units** | **Uncon-trolled** | **Baseline post-comb BL amine flour** | **NewTech pre-comb MWGS/DOE Eltron/SOF Co/Fluor** | **NewTech pre-comb MWGS/GR/DOE BP** | **NewTech pre-comb MW/GS/GR BP** | **NewTech oxyfuel FGRec-ASU APCI** | **NewTech oxyfuel FGRec-ITM APCI** |
|---|---|---|---|---|---|---|---|---|
| *Efficiency* | | | | | | | | |
| Overall | | | | | | | | |
| Capture system | | | | | | | | |
| *$CO_2$ balance* | | | | | | | | |
| $CO_2$ generated[a] | Million tonne/yr | 2.57 | 2.57 | 2.57 | 2.57 | 2.57 | 2.57 | 2.57 |
| $CO_2$ captured[a] | Million tonne/yr | 0.00 | 2.19 | 2.19 | 1.99 | 1.99 | 2.08 | 2.09 |
| $CO_2$-emitted[a] | Million tonne/yr | 2.57 | 0.38 | 0.38 | 0.59 | 0.59 | 0.49 | 0.48 |
| $CO_2$ avoided[a] | Million tonne/yr | 0.00 | 1.55 | 1.54 | 1.50 | 1.50 | 1.87 | 1.95 |
| Specific $CO_2$-emission; direct[a] | kg/kWh | 0.22 | 0.03 | 0.03 | 0.05 | 0.05 | 0.04 | 0.04 |
| $CO_2$ avoided/captured ratio | % | | 71 | 70 | 76 | 76 | 90 | 93 |
| *Non-$CO_2$-emissions*[a] | | | | | | | | |
| $NO_x$ | tonne/yr | 7087 | 254 | 2000 | 2000 | 2000 | 0 | 0 |
| $SO_2$ | tonne/yr | 5606 | 0 | 365 | 5606 | 5606 | 0 | 0 |
| *$CO_2$-costs* | | | | | | | | |
| $CO_2$ avoided absolute improval vs. baseline | USD/tonne | | **78.1** | **84.9** | **48.1** | **52.4** | **48.7** | **41.0** |
| | % | | 0 | 9 | −38 | −33 | −38 | −48 |
| $CO_2$ capture c absolute improval vs. baseline | USD/tonne | | 55.3 | 59.8 | 36.4 | 39.6 | 43.8 | 38.2 |
| | % | | 0 | 8 | −34 | −28 | −21 | −31 |

[a] At 100% onstream basis (8760 h/yr).

TABLE 16
UK $CO_2$-AVOIDED COST BASIC RESULTS AND PARTIAL SENSITIVITIES—GENERIC PRICES

| | | BL amine | MWGS/ DOE | MWGS/ GR/DOE | MWGS/ GR | FGRec- ASU | FGRec- ITM |
|---|---|---|---|---|---|---|---|
| *Basic results* | *Generic costs and prices* | **78.1** | **84.9** | **48.1** | **52.4** | **48.7** | **41.0** |
| | *Local costs and prices* | 85.2 | 94.0 | 52.4 | 57.3 | 54.6 | 49.3 |
| *Partial sensitivities* | *Generic costs and prices* | | | | | | |
| Capex | − 10% | 74.9 | 80.3 | 46.1 | 50.2 | 45.7 | 36.6 |
| | Excl. IDC | 75.2 | 80.7 | 46.3 | 50.3 | 45.9 | 36.9 |
| O&M | − 10% | 75.9 | 83.2 | 47.1 | 51.4 | 47.5 | 39.4 |
| Energy | − 10% fuel gas | 75.5 | 81.8 | 46.1 | 50.4 | 47.9 | 36.0 |
| Capture efficiency | − 10% | 90.9 | 98.9 | 55.4 | 60.4 | 54.8 | 45.9 |
| Non-$CO_2$ emission costs | Included | 66.3 | 76.0 | 39.6 | 43.9 | 38.6 | 31.3 |
| $CO_2$-transport and storage | Included | 113.1 | 120.1 | 84.3 | 88.6 | 77.8 | 68.9 |
| $CO_2$-transport and EOR | + $CO_2$-sale ($20/t) | 84.9 | 91.8 | 57.8 | 62.2 | 55.5 | 47.5 |
| Discount factor | 7% | 70.5 | 74.5 | 43.4 | 47.0 | 41.5 | 35.4 |
| | 13% | 86.6 | 96.5 | 53.3 | 58.5 | 56.8 | 47.2 |

TABLE 17
ALASKA KEY COST, PERFORMANCE INPUT DATA AND RESULTS—GENERIC PRICES

| **Summary economics Alaska—Prudhoe Bay Central Gas Facility (11 turbines)** | **Units** | **Uncontrolled** | **Baseline, Post-comb, BL Amine** | **NewTech, Pre-comb, VLS ATR** | **NewTech, Pre-comb, SE WGS** |
|---|---|---|---|---|---|
| *Plant outputs* | | | | | |
| Net power output | MW | 358 | 358 | 358 | 358 |
| Overall onstream factor | % | 98 | 98 | 98 | 98 |
| *Scenario–technology costs* | | | | | |
| Total capex, excl. IDC (CCGT and capture plants) | MUSD | 0 | 1012 | 713 | 771 |
| Specific total capex (per MW net power output) | | | | | |

(*continued*)

TABLE 17
CONTINUED

| **Summary economics Alaska—Prudhoe Bay Central Gas Facility (11 turbines)** | | **Units** | **Uncontrolled** | **Baseline, Post-comb, BL Amine** | **NewTech, Pre-comb, VLS ATR** | **NewTech, Pre-comb, SE WGS** |
|---|---|---|---|---|---|---|
| Capture systems capex | | MUSD | | 1012 | 713 | 771 |
| Specific capture systems capex (per annual tonne $CO_2$ avoided) | | USD/tonne | | 517 | 319 | 366 |
| Specific capture systems capex (per annual tonne $CO_2$ captured) | | USD/tonne | | 533 | 248 | 308 |
| Total O&M excl. energy | | MUSD/yr | 0 | 53 | 46 | 34 |
| Total O&M, incl. energy | | MUSD/yr | 0 | 47 | 81 | 55 |
| *Energy consumption (net increase capture system)* | | | | | | |
| Fuel gas[a] | | TBtu/yr | 0.0 | 0.0 | 10.7 | 6.6 |
| Electricity/steam[a] | | MW | 0 | − 18 | 0 | 0 |
| Coke[a] | | Million tonne/yr | 0 | 0 | 0 | 0 |
| *Efficiency* | | | | | | |
| Overall | | LHV | | | | |
| Capture system | | LHV | | | | |
| *$CO_2$ balance* | | | | | | |
| $CO_2$ generated[a] | | Million tonne/yr | 2.56 | 2.56 | 3.20 | 2.95 |
| $CO_2$ captured[a] | | Million tonne/yr | 0.00 | 1.90 | 2.88 | 2.50 |
| $CO_2$ emitted[a] | | Million tonne/yr | 2.56 | 0.66 | 0.32 | 0.45 |
| $CO_2$ avoided[a] | | Million tonne/yr | 0.00 | 1.96 | 2.24 | 2.10 |
| Specific $CO_2$-emission; direct[a] | | kg/kWh | 0.82 | 0.21 | 0.10 | 0.14 |
| $CO_2$ avoided/captured ratio | | % | | 103 | 78 | 84 |
| *Non-$CO_2$-emissions*[a] | | | | | | |
| $NO_x$ | | Tonne/yr | 0 | 0 | 0 | 0 |
| $SO_2$ | | Tonne/yr | 0 | 0 | 0 | 0 |
| *$CO_2$-costs* | | | | | | |
| $CO_2$ avoided cost | Absolute | USD/tonne | | **88.2** | **76.0** | **71.8** |
| | improval vs. baseline | % | | 0.0 | − 13.8 | − 18.5 |
| $CO_2$ capture cost | Absolute | USD/tonne | | 90.9 | 59.0 | 60.5 |
| | improval vs. baseline | % | | 0.0 | − 35.1 | − 33.5 |

[a] At 100% onstream basis (8760 h/yr).

TABLE 18
ALASKA $CO_2$-AVOIDED COST BASIC RESULTS AND PARTIAL SENSITIVITIES (GENERIC AND LOCAL PRICES)

| | | **BL amine** | **VLS-ATR** | **SEWGS** |
|---|---|---|---|---|
| *Basic results* | *Generic costs and prices* | **88.2** | **76.0** | 71.8 |
| | *Local costs and prices* | 129.6 | 80.7 | 84.9 |
| *Partial sensitivities* | *Generic costs and prices* | | | |
| Capex | −10% | 81.8 | 72.1 | 67.3 |
| | Excl. IDC | 82.3 | 72.4 | 67.7 |
| O&M | −10% | 85.4 | 73.9 | 70.2 |
| Energy | −10% fuel gas | 88.2 | 74.4 | 70.8 |
| Capture efficiency | −10% | 97.6 | 87.2 | 81.5 |
| Non-$CO_2$ emission costs | | | | |
| $CO_2$-transport and storage | Included | 88.3 | 76.1 | 71.9 |
| $CO_2$-transport and EOR | +$CO_2$-sale ($20/t) | 68.9 | 50.3 | 48.2 |
| Discount factor | 7% | 72.9 | 66.5 | 60.9 |
| | 13% | 105.3 | 86.7 | 84.2 |

This additional S&T-costs may in some cases be compensated if the captured $CO_2$ can realize a commercial value, e.g. sales to oilfield EOR-projects. If the captured $CO_2$-volumes can be sold at a price reflecting the customer's willingness to pay, i.e. the oilfield's net additional income from an EOR-project, it is possible more or less to compensate the S&T-costs. As we see from above, the UK and Norwegian scenarios need very profitable EOR-customers to neutralize the established S&T-costs, while the Alaskan and Canadian cases may earn large additional net profits from $CO_2$-sale, due to low unit S&T-costs.

*UK scenario data*
See Tables 15 and 16.

*Alaska scenario data*
See Tables 17 and 18.

*Norway scenario data*
See Tables 19 and 20.

*Canada scenario data*
See Tables 21 and 22.

TABLE 19
NORWAY KEY COST, PERFORMANCE INPUT DATA AND RESULTS—GENERIC PRICES

| **Summary economics gas power plant W-coast Norway** | **Units** | **Uncon-trolled** | **Baseline, post-comb, BL Amine Statoil/Fluor** | **BL-design 2, post-comb, Amine-Basis, Nexant Basis** | **BL-design 3, postcomb, Amine-Low Nexant Low** | **BL-design 4, post-comb, Amine-Integr, Nexant Integr-** | **NewTech, post-comb MembContKS1 MHI-Kværner** | **NewTech, post-comb, BIT Nex. Int + MHI-KS1** | **NewTech, pre-comb, HMR, Hydro** | **NewTech, pre-comb, SEWGS-02ATR, APCI/CCP** | **NewTech, pre-comb, SEWGS-AirATR, APCI/CCP** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Plant outputs* | | | | | | | | | | | |
| Net power output | MW | 392 | 323 | 322 | 332 | 345 | 335 | 357 | 361 | 360 | 424 |
| Overall onstream factor | % | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 |
| *Scenario-technology costs* | | | | | | | | | | | |
| Total capex, excl. IDC (CCGT and capture plants) | MUSD | 284 | 412 | 418 | 366 | 345 | 410 | 352 | 382 | 434 | 462 |
| Specific total capex (per MW net power output) | USD/kW | 724 | 1277 | 1296 | 1102 | 1002 | 1225 | 986 | 1058 | 1205 | 1089 |
| Capture system capex | MUSD | 0 | 129 | 134 | 82 | 61 | 127 | 69 | 98 | 150 | 178 |
| Specific capture system capex (per annual tonne $CO_2$ avoided) | USD/ tonne | | 148 | 155 | 92 | 66 | 139 | 70 | 84 | 147 | 147 |
| Specific capture system capex (per annual tonne $CO_2$ captured) | USD/ tonne | | 118 | 123 | 75 | 56 | 116 | 63 | 77 | 117 | 121 |
| Total O&M (incl. CCGT-plant) excl. fuel gas | MUSD/yr | 13 | 29 | 26 | 24 | 24 | 23 | 21 | 20 | 20 | 21 |
| Total O&M (incl. CCGT-plant) incl. fuel gas | MUSD/yr | 77 | 93 | 90 | 88 | 88 | 87 | 85 | 84 | 91 | 104 |
| *Energy consumption (total; basic and capture plants)* | | | | | | | | | | | |
| Fuel gas, HHV[a] | TBtu/yr | 22.5 | 22.5 | 22.5 | 22.5 | 22.5 | 22.5 | 22.5 | 22.5 | 25.2 | 29.0 |
| Electricity/stream[a] | 681 MW | 0 | 69 | 70 | 60 | 48 | 57 | 35 | 31 | 79 | 83 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coke[a] | | Million tonne/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| *Efficiency* | | | | | | | | | | | | |
| Overall | | LHV (%) | 57.6 | 47.4 | 47.3 | 48.8 | 50.6 | 49.2 | 52.5 | 53.0 | 47.2 | 48.2 |
| Capture system | | LHV (%) | | 82.3 | 82.2 | 84.7 | 87.9 | 85.5 | 91.1 | 92.1 | 81.9 | 83.7 |
| *$CO_2$ balance* | | | | | | | | | | | | |
| $CO_2$ generated[a] | | Million tonne/yr | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.42 | 1.64 |
| $CO_2$ captured[a] | | Million tonne/yr | 0.00 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.27 | 1.28 | 1.47 |
| $CO_2$ emitted[a] | | Million tonne/yr | 1.27 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.00 | 0.14 | 0.17 |
| $CO_2$ avoided[a] | | Million tonne/yr | 0.00 | 0.87 | 0.87 | 0.90 | 0.94 | 0.91 | 0.98 | 1.17 | 1.02 | 1.21 |
| Specific $CO_2$-emision, (direct emission per net power output | | kg/kWh | 0.370 | 0.0628 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.00 | 0.05 | 0.04 |
| $CO_2$ avoided/ captured ratio | | % | | 79 | 79 | 82 | 86 | 83 | 90 | 92.1 | 80 | 82 |
| *Non-$CO_2$-emissions*[a] | | | | | | | | | | | | |
| $NO_x$ | | tonne/yr | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 230 | 560 | 646 |
| $SO_2$ | | tonne/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| *$CO_2$-costs* | | | | | | | | | | | | |
| $CO_2$ avoided cost | Absolute improval vs. baseline | USD/ tonne | | **61.6** | **60.0** | **44.7** | **35.1** | **47.5** | **28.2** | **24.4** | **42.7** | **34.4** |
| | | % | | 0.0 | −3 | −27 | −43 | −23 | −54 | −60 | −31 | −44 |
| $CO_2$ capture cost | Absolute improval vs. baseline | USD/ tonne | | 49.0 | 47.6 | 36.8 | 30.2 | 39.5 | 25.3 | 22.5 | 34.1 | 28.2 |
| | | % | | 0 | −3 | −25 | −38 | −19 | −48 | −54 | −30 | −42 |
| *Power-generation cost* | | | | | | | | | | | | |
| Pre-$CO_2$ capture cost-tax | | USD/kWh | 0.034 | 0.053 | 0.053 | 0.048 | 0.045 | 0.049 | 0.043 | 0.043 | 0.048 | 0.045 |
| Post-$CO_2$ capture cost-tax | | USD/kWh | 0.042 | 0.054 | 0.054 | 0.049 | 0.046 | 0.050 | 0.044 | 0.043 | 0.049 | 0.046 |
| Pre-$CO_2$-tax | | Øre/kWh | 27.4 | 42.5 | 42.1 | 38.4 | 36.1 | 39.1 | 34.4 | 34.6 | 38.4 | 36.3 |
| Post-$CO_2$-tax | | Øre/kWh | 33.3 | 43.5 | 43.1 | 39.4 | 37.1 | 40.1 | 35.4 | 34.6 | 39.2 | 37.0 |

[a] At 100% onstream basis (8760 h/yr).

TABLE 20
NORWAY $CO_2$-AVOIDED COST BASIC RESULTS AND PARTIAL SENSITIVITIES — GENERIC PRICES

| | | **BL Amine** | **BL Amine, Nexant Basis** | **BL Amine, Nexant Low** | **BL Amine, Nexant Integr** | **Membr. Cont. KS-1** | **BIT** | **HMR** | **SEWGS-O2ATR** | **SEWGS-AirATR** |
|---|---|---|---|---|---|---|---|---|---|---|
| *Basic results* | *Generic costs and prices* | **61.6** | **60.0** | **44.7** | **35.1** | **47.5** | **28.2** | **24.4** | **42.7** | **34.4** |
| | *Local costs and prices* | 65.6 | 64.8 | 47.0 | 36.7 | 51.7 | 30.5 | 26.7 | 44.6 | 35.4 |
| *Partial Sensitivities* | *Generic costs and prices* | | | | | | | | | |
| Capex | −10% | 59.0 | 57.3 | 43.0 | 33.8 | 45.2 | 27.0 | 23.1 | 40.5 | 32.8 |
| | Excl. IDC | 59.2 | 57.5 | 43.1 | 33.9 | 45.3 | 27.1 | 23.2 | 40.7 | 32.9 |
| O&M | −10% | 59.5 | 58.1 | 43.2 | 33.8 | 46.2 | 27.3 | 23.7 | 41.9 | 33.8 |
| Energy | −10% power loss | 59.2 | 57.6 | 42.7 | 33.6 | 45.6 | 27.2 | 23.6 | 40.4 | 32.4 |
| Capture $CO_2$-volume | −10% | 70.5 | 68.6 | 50.9 | 39.8 | 54.0 | 31.8 | 27.4 | 48.8 | 39.2 |
| Non-$CO_2$ emission costs | | | | | | | | | | |
| $CO_2$-transport and storage | Included | 93.8 | 92.2 | 75.8 | 64.9 | 78.2 | 56.7 | 48.2 | 70.0 | 57.5 |
| $CO_2$-transport and EOR | +$CO_2$-sale ($20/t) | 68.6 | 67.0 | 51.5 | 41.6 | 54.2 | 34.4 | 26.5 | 44.9 | 33.1 |
| Discount factor | 7% | 55.2 | 53.4 | 40.4 | 32.0 | 41.8 | 25.3 | 21.2 | 37.4 | 30.5 |
| | 13% | 68.8 | 67.4 | 49.6 | 38.7 | 54.0 | 31.6 | 28.0 | 48.6 | 38.9 |

TABLE 21
CANADA KEY COST, PERFORMANCE INPUT DATA AND RESULTS—GENERIC PRICES

| **Summary economics Canada Coke Gasifier** | **Units** | **Uncontrolled** | **Baseline pre-comb IGCC and Capt** | **NewTech pre-comb IGCC and Adv.Capt-1** | **NewTech pre-comb IGCC and Adv.Capt-100** |
|---|---|---|---|---|---|
| *Plant outputs* | | | | | |
| Combined net power/ steam/hydrogen output | MW | 588 | 699 | 734 | 734 |
| Overall onstream factor | % | 91 | 91 | 91 | 91 |
| *Scenario–technology costs* | | | | | |
| Total capex, excl. IDC (CCGT and capture plants) | MUSD | 822 | 1341 | 1338 | 1511 |
| Specific total capex (per MW net power output) | USD/kW | 1398 | 1919 | 1823 | 2058 |
| Capture systems capex | MUSD | | 519 | 516 | 689 |
| Specific capture systems capex (per annual tonne $CO_2$ avoided) | USD/tonne | | 98 | 99 | 132 |
| Specific capture systems capex (per annual tonne $CO_2$ captured) | USD/tonne | | 76 | 80 | 107 |
| Total O&M (incl. CCGT-plant) excl. feed coke | MUSD/yr | 37 | 61 | 60 | 67 |
| Total O&M (incl. CCGT-plant), incl. feed coke | MUSD/yr | 52 | 134 | 123 | 130 |
| *Energy consumption (total; basic and capture plants)* | | | | | |
| Fuel gas[a] | TBtu/yr | 0 | 0 | 0 | 0 |
| Electricity loss[a] | MW | 0 | 182 | 147 | 147 |
| Coke[a] | Million tonne/yr | 1.7 | 2.5 | 2.5 | 2.5 |
| *Efficiency* | | | | | |
| Overall | LHV | | | | |
| Capture system | LHV | | | | |
| *$CO_2$ balance* | | | | | |

(*continued*)

TABLE 21
CONTINUED

| **Summary economics Canada Coke Gasifier** | | **Units** | **Uncontrolled** | **Baseline pre-comb IGCC and Capt** | **NewTech pre-comb IGCC and Adv.Capt-1** | **NewTech pre-comb IGCC and Adv.Capt-100** |
|---|---|---|---|---|---|---|
| $CO_2$ generated[a] | | Million tonne/yr | 4.90 | 7.40 | 7.34 | 7.34 |
| $CO_2$ captured[a] | | Million tonne/yr | 0.00 | 6.80 | 6.44 | 6.44 |
| $CO_2$-emitted[a] | | Million tonne/yr | 4.90 | 0.60 | 0.90 | 0.90 |
| $CO_2$ avoided[a] | | Million tonne/yr | 0.00 | 5.28 | 5.22 | 5.22 |
| Specific $CO_2$-emission; direct[a] | | kg/kWh | 0.95 | 0.10 | 0.14 | 0.14 |
| $CO_2$ avoided/captured ratio | | % | | 78 | 81 | 81 |
| *Non-$CO_2$-emissions*[a] | | | | | | |
| $NO_x$ | | Tonne/yr | | | | |
| $SO_2$ | | Tonne/yr | | | | |
| *$CO_2$-costs* | | | | | | |
| $CO_2$ avoided cost | Absolute improval vs. baseline | USD/tonne | | **14.5** | **12.2** | **18.0** |
| | | % | | 0.0 | − 15.9 | 24.5 |
| $CO_2$ capture cost | Absolute improval vs. baseline | USD/tonne | | 11.1 | 9.9 | 14.6 |
| | | % | | 0 | − 11.3 | 31.3 |
| *Power-generation cost* | | | | | | |
| Pre-$CO_2$-tax | | USD/kWh | 0.032 | 0.042 | 0.041 | 0.044 |
| Post-$CO_2$-tax | | USD/kWh | 0.051 | 0.044 | 0.043 | 0.047 |

[a] At 100% onstream basis (8760 h/yr).

TABLE 22
CANADA $CO_2$-AVOIDED COST BASIC RESULTS AND PARTIAL SENSITIVITIES—GENERIC PRICES

| | | **Baseline IGCC and capture** | **IGCC and adv. capture** |
|---|---|---|---|
| *Basic results* | *Generic costs and prices* | **14.5** | **12.2** |
| | *Local costs and prices* | 14.7 | 12.2 |
| *Partial sensitivities* | *Generic costs and prices* | | |
| Capex | −10% | 14.2 | 11.9 |
| | excl. IDC | 14.2 | 11.9 |
| O&M | −10% | 14.3 | 12.1 |
| Energy | −10% fuel coke | 14.2 | 11.9 |
| Capture efficiency | −10% | 16.6 | 13.9 |
| Non-$CO_2$ emission costs | | | |
| $CO_2$-transport and storage | Included | 22.2 | 19.9 |
| $CO_2$-transport and EOR | +$CO_2$-sale ($20/t) | −10.7 | −9.8 |
| Discount factor | 7% | 13.0 | 10.9 |
| | 13% | 16.1 | 13.6 |

## NOMENCLATURE

| | |
|---|---|
| ASU | Air separation unit |
| BAT | Best available technology |
| BL | Baseline |
| BIT | Best integrated technology |
| Capex | Capital expenditure |
| CCGT | Combined cycle gas turbine |
| CCP | $CO_2$ capture project |
| CE | Cost estimation |
| CEM | Common economic model |
| CEMT | Common economic model team |
| CERG | Cost estimation review group |
| $CO_2$ | Carbon dioxide |
| $CO_2$LDSEP | Advanced $CO_2$ separation technology (IGCC Canada scenario) |
| COE | Cost of electricity (unit power generation cost) |
| $CO_2$SE | Specific $CO_2$ emission (ton $CO_2$/kWh) |
| DOE | US Department of Energy |
| EOR | Enhanced oil recovery |
| FG | Flue gas |
| GHG | Greenhouse gas |
| GRACE | Grangemouth advanced $CO_2$ capture project (MWGS-program sponsored by EU) |
| H&B | Heaters and boilers (UK refinery) |
| IGCC | Integrated gasification combined cycle |
| IDC | Interest during construction |
| ITM | Ion transport membrane |
| KS-1 | Mitsubishi/Kansai's new absorbent |
| KWh | Kilowatt-hour |
| MBtu | Million British thermal units |
| MEA | Mono-ethanol amine absorbent |
| MUSD | Million US dollars |
| MHI | Mitsubishi heavy industries |
| MW | Megawatt |

| | |
|---|---|
| MWh | Megawatt-hour |
| MWGS | Membrane water gas shift |
| NOK | Norwegian Kroner |
| $NO_x$ | Nitrogen oxides |
| NPV | Net present value |
| O&M | Operation and maintenance cost |
| Opex | Operating expenditure |
| Pd | Palladium |
| PV | Present value |
| R&D | Research and Development |
| ROR | Rate of return |
| RPE | Responsible process engineer |
| $SO_2$ | Sulfur dioxide |
| SEWGS | Sorption enhanced water gas shift |
| S–T matrix | Scenario–Technology matrix |
| TF | Task force |
| TIC | Total installed cost (investments) |
| tonne | metric ton, 1000 kilo |
| TP | Technology provider |
| T&S cost | $CO_2$ transportation and storage cost |
| USD | US Dollar |
| VLS-ATR | Very large scale-auto thermal reformer |
| yr | Year |

## ACKNOWLEDGEMENTS

The author would like to recognize the whole CEM team that participated from the very beginning of the project. Table A3 shows the full team and associated members. During the last phase of the project I would especially mention the close and very good cooperation with the Cost Estimator consultants—Nils Eldrup and Svein Bjørnsen. I also wish to recognize the valuable comments and critique provided by Henrik Andersen, Svein Bjørnsen, Lars Ingolf Eide, Dag Eimer, Cliff Lowe & Ivano Miracca during the final review of this report.

## APPENDIX A: INITIAL CEM OBJECTIVES

In the JIP agreement among the CCP-participants (March 2000) refers the following CEM-objectives:

1. A CEM will be developed as a part of the work program. The model will be used to establish a common set of metrics among the participants.
2. The CEM will be used to evaluate the overall cost of $CO_2$-sequestration, including the component costs of $CO_2$ separation and capture, and geologic sequestration. A set of agreed indices will be identified which will facilitate the easy comparison of different studies, technologies and targets.
3. The CEM will be based on a set of generic economic and project assumptions. The generic case parameters will be established by a small team in consultation with the Executive Board.
4. A risked estimate of the potential after development to achieve material reductions in the cost of geological sequestration will be a key criterion for comparison of various technology options.
5. The CEM will be made available to the participants for their own internal use and will contain sufficient detail and flexibility to allow evaluation of specific projects in a manner that is consistent with each company's internal guidelines.

### *$CO_2$-Cost Calculations Norway Baseline*

See Tables A1 and A2.

### *$CO_2$-/$NO_x$-/$SO_2$-Emission Costs—Market References*

See Figures A1 and A2 Table A3.

TABLE A1
GROSS POWER OUTPUT BASIS, INCL. COST OF "POWER IMPORT" AT UNCONTROLLED POWERGEN-COST AND DIRECT + INDIRECT $CO_2$-EMISSIONS

| **Main element** | **Decomposition** | **Uncontrolled case** | | **Baseline case** | | **Delta baseline—uncontrolled** |
|---|---|---|---|---|---|---|
| | | **Calculation** | **Result** | **Calculation** | **Result** | |
| Capex | Accum. Capex × Capital charge factor × Interest During Construction factor | 283.84 mUSD × 11.02% × 1.102 | = 34.45 mUSD | 412.35 mUSD × 11.02% × 1.102 | = 50.05 mUSD | |
| Opex, excl. energy | Fixed O&M + variable O&M × onstream factor | 1140 mUSD + 190 mUSD × 95% | = 13.21 mUSD | 16.80 mUSD + 12.50 mUSD × 95% | = 28.68 mUSD | |
| Fuel gas | Fuel gas consumption × HHV/LHV-factor × onstream factor × fuel gas price | 20.37 TBtu/yr × 1.103 × 95% × 3.0 USD/mBtu | = 64.00 mUSD | 20.37 TBtu/yr × 1.103 × 95% × 3.0 USD/ mBtu | = 64.00 mUSD | |
| "Power import"/ power loss | Power loss × h/yr × onstream factor × uncontrolled powergen cost | | | 69.2 MW × 8760 h/yr × 95% × 0.0342USD/ kWh | = 19.71 mUSD | |
| Annual powergen cost | | | = 111.65 mUSD | | = 162.43 mUSD | |
| Unit powergen cost | Annual powergen cost/annual gross (uncontrolled) power output | 111.65 mUSD/ (392 MW × 8760 h/yr × 95%) | = 0.0342 USD/kWh | 162.43 mUSD/(392 MW × 8760 h/yr × 95%) | = 0.0498 USD/ kWh | = USD 0.0156/ kWh |
| Specific $CO_2$-emission, direct | Annual $CO_2$-emission/ annual net power output | 1.27 mtonne $CO_2$ × 95%/(392MW × 8760 h/yr × 95%) | = 0.370 tonne $CO_2$/MWh | 1.27 mtonne $CO_2$ × (1 − 0.86) × 95% / (392 MW × 8760 h/yr × 95%) | = 0.052 tonne $CO_2$/MWh | = 0.318 tonne $CO_2$/MWh |

(*continued*)

TABLE A1
CONTINUED

| Main element | Decomposition | Uncontrolled case | | Baseline case | | Delta baseline—uncontrolled |
|---|---|---|---|---|---|---|
| | | Calculation | Result | Calculation | Result | |
| Specific $CO_2$-emission, direct + indirect | (Direct emission + $CO_2$ in power "import"/loss) per MWh power output | | = 0.370 tonne $CO_2$/MWh | (0.052 tonne$CO_2$ /MWh + 69.2 MW × 8760 h/yr × 0.370 tonne$CO_2$ / MWh)/ (392 MW × 8760 h/yr) | = 0.117 tonne $CO_2$/MWh | = 0.253 tonne $CO_2$/MWh |
| $CO_2$-capture cost | Delta powergen cost/Delta specific $CO_2$-emission; direct | | | | | = USD 48.98 per tonne $CO_2$ = USD 15.6/MWh/ 0.318 tonne CO2/MWh |
| $CO_2$-avoided cost | Delta powergen cost/Delta specific $CO_2$-emission;direct + indirect | | | | | = USD 61.63 per tonne $CO_2$ = USD 15.6/MWh/0.253 tonne$CO_2$/MWh |

TABLE A2
NET POWER OUTPUT BASIS, EXCLUDING “POWER IMPORT” STREAM

| **Main element** | **Decomposition** | **Uncontrolled case Calculation** | **Result** | **Baseline case (BL) Calculation** | **Result** | **Delta baseline—uncontrolled** |
|---|---|---|---|---|---|---|
| Capex | Accum. Capex × Capital charge factor × Interest during construction factor | 283.84 mUSD × 11.02% × 1.102 | = 34.45 mUSD | 412.35 mUSD × 11.02% × 1.102 | = 50.05 mUSD | |
| Opex, excl. energy | Fixed O&M + variable O&M × onstream factor | 11.40 mUSD + 1.90 mUSD × 95% | = 13.21 mUSD | 16.80 mUSD + 12.50 mUSD × 95% | = 28.68 mUSD | |
| Fuel gas | Fuel gas consumption × HHV/LHV-factor × onstream factor × fuel gas price | 20.37 TBtu/yr × 1.103 × 95% × 3.0 USD/mBtu | = 64.00 mUSD | 20.37 TBtu/yr × 1.103 × 95% × 3.0 USD/mBtu | = 64.00 mUSD | |
| Annual powergen cost | | | = 111.65 mUSD | | = 142.72 mUSD | |
| Unit powergen cost | Annual powergen cost/annual net power output | 111.65 mUSD/(392 MW × 8760 h/yr × 95%) | = 0.0342USD/ kWh | 142.72 mUSD /((392 − 69)MW × 8760 h/yr × 95%) | = USD 0.0531/ kWh | = USD 0.0189/ kWh |
| Specific $CO_2$-emission, direct | Annual $CO_2$-emission/ annual net power output | 1.27 mtonne $CO_2$ × 95%/ (392MW × 8760 h/yr × 95%) | = 0.370 tonne $CO_2$/MWh | 1.27 mtonne $CO_2$ × (1 − 0.86) × 95% /((392 − 69) MW × 8760 h/yr × 95%) | = 0.063 tonne$CO_2$/ MWh | = 0.307 tonne $CO_2$/MWh |
| $CO_2$-capture cost | Delta powergen cost × net power output BL/captured $CO_2$-BL | | | | | = USD 48.98 per tonne $CO_2$ = USD 18.9/MWh × (392 − 69)MW × 8760 h/ (1.27mtonne $CO_2$ × 86%) |
| $CO_2$-avoided cost | Delta powergen cost/Delta specific $CO_2$-emission; direct | | | | | = USD 61.63 per tonne $CO_2$ = USD 18.9/MWh /0.307 ton$CO_2$/MWh |

TABLE A3
COMMON ECONOMIC MODELING TEAM MEMBERS

| | 2000 | 2001 | 2002 | 2003–2004 |
|---|---|---|---|---|
| Team leader | Robert Moore, BP | Robert Moore, BP | Torgeir Melien, Hydro | Torgeir Melien, Hydro |
| Members | Geoffrey Johns, Suncor<br>Arthur Lee, Chevron Texaco<br>Torgeir Melien, Hydro<br>Mario Molinari, ENI | Geoffrey Johns, Suncor<br>Arthur Lee, Chevron Texaco<br>Torgeir Melien, Hydro<br>Mario Molinari, ENI<br>Trude Sundset, Statoil | Stewart Hayward, Shell<br>Geoffrey Johns, Suncor<br>Arthur Lee, Chevron Texaco<br>Mario Molinari, ENI | Stewart Hayward, Shell<br>Mario Molinari, ENI<br>Michael Wilkinson, BP |
| Technology team representatives | | | | Jan Assink, Shell Francesco Saviano, ENI<br>Odd Furuseth, Statoil<br>Dag Eimer, Hydro |
| Cost estimating consultants | | | | Nils Eldrup, Eldrup AS<br>Svein Bjørnsen, Costech AS |

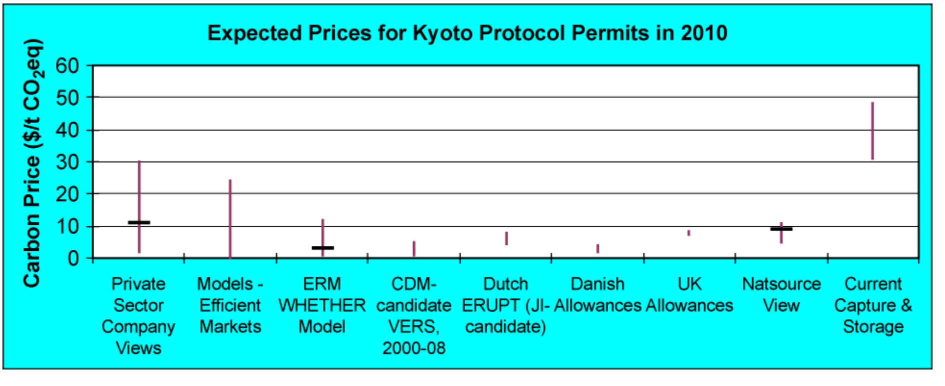


**Figure A1:** Expected prices for Kyoto Protocol $CO_2$ Permits in 2010.

**Platts Monthly Broker Emissions Index**

Index for Dec. 15 option expiry

| | Bid | Offer | Index |
|---|---|---|---|
| SO2 - Spot | 217.00 | 220.75 | *219.50 |
| NOx | | | |
| 2003 | 2409 | 2650 | *2560 |
| 2004 | 2550 | 2688 | 2700 |
| 2005 | 3660 | 3920 | 3750 |

**Platts Weekly Broker Emissions Index**

As of week's end, Jan. 9

| | Bid | Offer | Index |
|---|---|---|---|
| SO2 - Spot | 226.50 | 230.50 | *228.50 |
| NOx | | | |
| 2004 | 2638 | 2813 | *2726 |
| 2005 | 3913 | 4025 | *3969 |
| 2006 | 2675 | 2875 | 2800 |

*These indexes are done in cooperation with Air Liquid Advisors, Cantor Fitzgerald, Evolution Markets LLC, ICAP Energy, Natsource LLC and United Power Inc. For comments or questions email: cosi@pietts.com.*

*Asterisk connotes bid/ask mean for Index value. No asterisk connotes consensus last done trade.*

**Figure A2:** Current $NO_x$ and $SO_2$ Broker Emission Indices.

**REFERENCE**

Cost Estimating Report 2004, Nils Eldrup/Svein Bjørnsen, February 20th, 2004.