Overview of IEA GHG Activities on Bio-CCS

Ameena Camps, Tim Dixon, Steve Goldthorpe, Stanley Santos
IEA Greenhouse Gas R&D Programme
Cheltenham, UK

Bio-CCS Workshop
Holland House Hotel, Cardiff
25th October 2011
Presentation Overview

- **IEA Greenhouse Gas R&D Programme**
- **Overview of IEAGHG’s Activities on Bio-CCS**
  - Completed Studies
  - On-Going Studies
- **Techno-Economic Evaluation – Biomass Fired and Co-Fired Power Plant with CO2 Capture**
  (IEAGHG Report No.:)
IEA Greenhouse Gas R&D Programme

• A collaborative research programme founded in 1991
• Aim: Provide members with definitive information on the role that technology can play in reducing greenhouse gas emissions.
• Producing information that is:
  ✓ Objective, trustworthy, independent
  ✓ Policy relevant but NOT policy prescriptive
  ✓ Reviewed by external Expert Reviewers
  ✓ Subject to review of policy implications by Members
• IEA GHG is an IEA Implementing Agreement in which the Participants contribute to a common fund to finance the activities.
• Activities: Studies and Reports (>120); International Research Networks: Wells, Risk, Monitoring, Modelling, Oxyfuel, Capture, Social Research, Solid Looping; Communications (GHGT conferences, IJGGC, etc); facilitating and focusing R&D and demonstration activities e.g. Weyburn
What IEAGHG does

• **Technical evaluations of mitigation options**
  - Comparative analyses with standardised baseline

• **Assist international co-operation**
  - International research networks

• **Assist technology implementation**
  - Near market research
  - GCCSI

• **Disseminate information**
Members and Sponsors
Global Policy Context

- National/Corporate policy setting
- National/Corporate research programmes
- Implementation actions
Industry CCS Workshop

“Challenges and Opportunities of CO₂ Capture & Storage in the Iron and Steel Industry”

Steel Institute VDEh Auditorium
Dusseldorf, Germany
8th - 9th November 2011
Completed Studies

- Techno-Economics of Biomass Fired or Co-Fired Power Plant with Post Combustion Capture
  (IEAGHG Report No.: 2009/09)

- Global Potential of Biomass and CO2 Capture Storage
  (IEAGHG Report No.: 2011/06)

- Contribution to the UNIDO Industry CCS Roadmap
  [http://www.iea.org/Papers/roadmaps/ccs_industry.pdf](http://www.iea.org/Papers/roadmaps/ccs_industry.pdf)
Potential for Biomass and Carbon Dioxide Capture and Storage (IEAGHG 2011/06)

- Global & regional first order assessment of potential for BE-CCS
- Technical, Realisable & Economic Potential

- Global technical potential: up to c. 10 Gt CO₂ eq/yr, greatest potential for negative emissions for BIGCC-CCS and CFB-CCS.
- Significant compared to IEA ETP (2010) estimate of 43 Gt of global CO₂ emissions reductions required from the energy sector by 2050

As presented by Pieter van Breevoort of Ecofys earlier today
IEAGHG On-Going Activities on Bio-CCS

- **Follow up on IEAGHG 2011/06 study**
  - Biomass CCS Website
  - Global Potential of Biogas with CCS
- **Biomass XtL with CCS**
  - Focus on addressing the needs for the Aviation Industry
  - Touch on the transport sector (Bio-diesel and Bio-ethanol)
- **Bio-CCS Application – Pulp and Paper Industry (Techno-Economics)**
- **Biomass CCS – Guidance for the Accounting of Negative Emissions**
Addressing the Needs of Biofuel for the Aviation Industry

- **EU ETS – the inclusion of Aviation Industry**
- **Industry assessing options to produce their own fuel**
  - Biomass XtL
    - MSW feedstock
  - Waste Oil Reprocessing
  - etc... etc...
Follow on Study: Biogas & Website

- Two biofuels routes assessed in Potential for Biomass and Carbon Capture and Storage – FT diesel & bioethanol
- Review proposed benefit of considering production of biogas with CCS.
- The follow on study considers most applicable routes identified through experts and a literature review, with additional assessment in terms of growth of demand for natural gas & to what extent biogas can replace other energy fuels.
- Similar approach determining potential net GHG emissions
- Model used in assessment will be made available on IEAGHG website as an interactive tool.
Techno-Economic Evaluation of Biomass Fired or Co-Fired Power Plant with Post Combustion Capture

Bio-CCS Workshop
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25th October 2011
Acknowledgement

- This presentation is the results of the work done by Foster Wheeler Italiana for IEA Greenhouse Gas R&D Programme

- We would like to thank...
  - Paolo Cotone
  - Franco Gasparini
  - Rosa Maria Domenichini
Outline

• Motivation of this Study (Discussion Points)
• Study Cases
• Design Basis
• Summary of Performance Results
• Economic Analysis
• Concluding Remarks
Discussion Points

- **How to consider the “Accounting” of CO₂ Captured from Biomass Fired Power Plant**
  - The discussion is now centred on how to consider the CO₂ emitted from biomass-fired power plants, if it is counted as “CO₂ neutral” and if stored, whether how this could be considered or accounted as a “negative” CO₂ emission.
  - Validation / Accounting methodology when CO₂ captured from Co-Fired Power Plant.

- **One of the questions/Issues addressed in this study:**
  - “What should be the cost of CO₂ emissions avoided that would make CCS an attractive option to be incorporated into a biomass fired power plant assuming that the stored CO₂ from a biomass fired power plant could generate an additional revenue as CO₂ credit”
Study Cases

- **Case 1**: Nominal 500 MWe (net) Coal co-fired with Biomass Supercritical PC Power Plant.
- **Case 2**: Nominal 500 MWe (net) Coal co-fired with Biomass Supercritical CFB Power Plant.
- **Case 3**: Nominal 250 MWe (net) Biomass (standalone) CFB Power Plant.
- **Case 4**: Nominal 75 MWe (net) Biomass (standalone) BFB Power Plant.

- For all the four cases, power plants without and with CO$_2$ capture are evaluated
Design Basis (Summary)

- **Feedstocks:**
  - Eastern Australian Bituminous (LHV = 25.87 MJ/kg; Coal S = 1.1% wt, dry ash free basis)
  - Biomass is a clean, virgin wood chips (LHV = 7.3 MJ/kg)

- **Location of the Power Plant**
  - NE Coast of The Netherlands

- **Reference Ambient Temperature:** 9°C

- **Cooling Water Type:**
  - Once through sea water cooling
  - Cooling temperature: 12°C → 19°C
Design Basis (Summary)

- **Emissions Limit;**
  - Based on the requirement of the EC Large Combustion Directives.
    - NOx (as NO₂): \( \leq 200 \text{ mg/Nm}^3(@ 6\%_v \text{ O}_2 – \text{dry}) \)
    - SOx (as SO₂): \( \leq 200 \text{ mg/Nm}^3(@ 6\%_v \text{ O}_2 – \text{dry}) \)
    - Particulates: \( \leq 30 \text{ mg/Nm}^3(@ 6\%_v \text{ O}_2 – \text{dry}) \)

- **CO₂ Characteristics at Battery Limits**
  - Delivered Pressure: 110 Bar
  - CO₂ Purity: \( \geq 99\% \ (\leq 10 \text{ ppm H}_2\text{O}) \)
## Summary – Cases

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Boiler Technology</th>
<th>Fuel Feedstock</th>
<th>Nominal Rating</th>
<th>CO2 Capture</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>PC (supercritical)</td>
<td>Coal (90%) + Biomass (10%)*</td>
<td>500MWe (net)</td>
<td>No</td>
</tr>
<tr>
<td>1b</td>
<td>PC (supercritical)</td>
<td>Coal (90%) + Biomass (10%)*</td>
<td>500MWe (net)</td>
<td>Yes</td>
</tr>
<tr>
<td>2a</td>
<td>CFB (supercritical)</td>
<td>Coal (90%) + Biomass (10%)*</td>
<td>500MWe (net)</td>
<td>No</td>
</tr>
<tr>
<td>2b</td>
<td>CFB (supercritical)</td>
<td>Coal (90%) + Biomass (10%)*</td>
<td>500MWe (net)</td>
<td>Yes</td>
</tr>
<tr>
<td>3a</td>
<td>CFB (subcritical)</td>
<td>Biomass</td>
<td>250MWe (net)</td>
<td>No</td>
</tr>
<tr>
<td>3b</td>
<td>CFB (subcritical)</td>
<td>Biomass</td>
<td>250MWe (net)</td>
<td>Yes</td>
</tr>
<tr>
<td>4a</td>
<td>BFB (subcritical)</td>
<td>Biomass</td>
<td>75MWe (net)</td>
<td>No</td>
</tr>
<tr>
<td>4b</td>
<td>BFB (subcritical)</td>
<td>Biomass</td>
<td>75MWe (net)</td>
<td>Yes</td>
</tr>
</tbody>
</table>

* Based on thermal input (LHV value)
Case 1a - Biomass Co-Fired SC PC Boiler Power Plant w/o CO₂ capture

Unit 1000
Storage and handling of solids materials

Unit 2000
Boiler Island & De NOx System
- Biomass
- Coal
- Fly & Bottom Ash
- IP Steam
- HP Steam
- IP Steam to RHT

Ammonia
- Air

Limestone
- Make-up Water

Unit 2300
FGD System
- Flue Gas
- FeedWater
- Gypsum
- Effluent
- Flue Gas to stack

Unit 3000
Steam Turbine & Preheating Line
- Cooling Water
Case 1a (Power Plant Features)

- **Power Plant Capacity**
  - Actual Net Power Output: 518.9 MWe

- **Boiler is commercially available / proven**

- **Boiler is co-fired with 10% Biomass (LHV basis); No pre-drying of biomass**

- **Steam Conditions:**
  - 580°C HP (275 Bar) / 600°C RH (55 Bar)
  - Boiler Efficiency: ~93%

- **SCR and FGD are installed to meet the emissions required.**
Case 1b - Biomass Co-Fired SC PC Boiler Power Plant with CO₂ capture
Case 1b (Power Plant Features)

- **Boiler is the same size with Case 1a. Due to extraction of low pressure steam from the steam turbine for the reboiler of the CO₂ capture plant – actual output is reduced.**

- **Actual Net Power Output:** 399 MWe

- **SCR and FGD are installed to meet the 10 ppm and 20 ppm level for SO₂ and NO₂ respectively to reduce the MEA degradation.**
  - Deep removal of SOx by the Limestone FGD should be demonstrated.

- **Due to removal of CO₂ from the flue gas – NOx level (mg/Nm³) should be expected higher (as compared to Case 1a)**
  - NOx removal level at SCR outlet should be 15% lower.
Case 2a - Biomass Co-Fired SC CFB Boiler Power Plant w/o CO$_2$ capture
Case 2a (Power Plant Features)

- **Power Plant Capacity**
  - Actual Net Power Output: ~521 MWe

- **Boiler is based on supercritical boiler technology which is commercially available / proven**

- **Boiler is co-fired with 10% Biomass (LHV basis); No pre-drying of biomass**

- **Steam Conditions:**
  - 580°C HP (275 Bar) / 600°C RH (60 Bar)
  - **Only limestone injection into the boiler is included. Ca/S ratio of 2.84 is used to achieve the minimum emissions required.**
Case 2a (Power Plant Features)

- **No SCR is installed. Required NOx emission is achieved by the CFB itself. Lower NOx emission is expected due to lower combustion temperature in the CFB boiler.**

- **Special Feature of the Power Plant:**
  - A plastic heat exchanger is installed downstream of the ID fan to maximise the heat recovery thus achieving some efficiency gain. (Expected flue gas temperature at stack ~90°C)
Case 2b - Biomass Co-Fired SC CFB Boiler Power Plant with CO₂ capture

Unit 1000
Coal & Ash Handling

Unit 2000
Boiler Island

Unit 3000
Steam Turbine & Preheating Line

Unit 4000
FGD System

Unit 5000
CO₂ Capture Plant

Unit 6000
CO₂ Compression & Drying
Case 2b (Power Plant Features)

- **Boiler is the same size with Case 2a. Due to extraction of low pressure steam from the steam turbine for the reboiler of the CO₂ capture plant – actual output is reduced.**
- **Actual Net Power Output:** ~390 MWe
- **To achieve the 10 ppm SOx level, in addition to the limestone that is injected into the boiler with a Ca/S ratio of 1, an external FGD has been installed.**
- **Unlike Case 2a, there will be no plastic heat exchanger installed downstream of the ID fan due to the installed FGD.**
Case 2b – Power Plant Features

- **No SCR is installed. It is expected that NOx level required will be met by the CFB Boiler itself.**
  - NO₂ in flue gas (15-20% of NOx) is considered tolerable by the MEA without further abatement in the SCR system.

- **N₂O at boiler outlet is expected to be low (~14 mg/Nm³) due to the operating temperature in the bed considered.**
  - N₂O is not expected to be removed by the MEA.
  - The possible formation of stable salts from N₂O should be investigated with the solvent suppliers.
## Performance of the Power Plants - Summary

<table>
<thead>
<tr>
<th>Case</th>
<th>Plant Type</th>
<th>Nominal Size</th>
<th>SCR</th>
<th>FGD</th>
<th>CO₂ Capture</th>
<th>Net Efficiency</th>
<th>Net output</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>SC PF boiler</td>
<td>500 MWe</td>
<td>Yes</td>
<td>Yes</td>
<td>0</td>
<td>44.8%</td>
<td>518.9 MWe</td>
</tr>
<tr>
<td>1b</td>
<td>SC PF boiler</td>
<td>500 MWe</td>
<td>Yes</td>
<td>Yes</td>
<td>90%</td>
<td>34.5%</td>
<td>398.9 MWe</td>
</tr>
<tr>
<td>2a</td>
<td>SC CFB boiler</td>
<td>500 MWe</td>
<td>No</td>
<td>No</td>
<td>0</td>
<td>45.1%</td>
<td>521.4 MWe</td>
</tr>
<tr>
<td>2b</td>
<td>SC CFB boiler</td>
<td>500 MWe</td>
<td>No</td>
<td>Yes</td>
<td>90%</td>
<td>33.8%</td>
<td>390.5 MWe</td>
</tr>
</tbody>
</table>
Economic Assessment

- **Basic Assumptions & Assessment Criteria**
  - **Availability:** 90% (w/o capture) 88% (w/ capture)
  - **Cost of coal:** 2.90 €/GJ
  - **Cost of biomass:** 8.39 €/GJ
  - **Plant cost:** in Euro (May 2009) (1 € = 1.35 US $)
  - **Discount Rate:** 10% (Annual Basis)
  - **Plant life:** 25 years
  - **CO₂ transport cost:** Not considered
Economic Analysis (cont’d)
Estimated CAPEX

<table>
<thead>
<tr>
<th>Case</th>
<th>Total Investment cost Million of Euro</th>
<th>Specific Cost Euro/kW</th>
</tr>
</thead>
<tbody>
<tr>
<td># 1a</td>
<td>657.21</td>
<td>1267</td>
</tr>
<tr>
<td># 1b</td>
<td>824.32</td>
<td>2066</td>
</tr>
<tr>
<td># 2a</td>
<td>707.28</td>
<td>1357</td>
</tr>
<tr>
<td># 2b</td>
<td>918.37</td>
<td>2352</td>
</tr>
</tbody>
</table>
Accounting of CO$_2$ Avoided Cost

• **Questions to be resolved (ie. tasks of policy development)**
  
  • Choice of Reference Power Plant to account for the overall negative emissions when CO2 from biomass fired power plant?
  
  • If 90% of the CO2 captured... How would you be able to account for the negative emissions?
## Manner to Calculate CO2 Avoided by this Study

### Table A.6.1: Summary of CO2 Emissions of the Biomass Fired or Co-Fired Power Plant

<table>
<thead>
<tr>
<th></th>
<th>Actual CO2 Emissions</th>
<th>CO2 from Coal</th>
<th>CO2 from Biomass</th>
<th>Total CO2 Captured</th>
<th>Equivalent CO2 Emissions</th>
<th>CO2 avoided with resp to conventional coal</th>
<th>CO2 avoided with resp to NGCC</th>
</tr>
</thead>
<tbody>
<tr>
<td>SC PC Boiler with coal (without CO2 capture)</td>
<td>722.8</td>
<td>722.8</td>
<td>-</td>
<td>-</td>
<td>722.8</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>NGCC (without CO2 capture)</td>
<td>359.0</td>
<td>359.0</td>
<td>-</td>
<td>-</td>
<td>359.0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>SC PC boiler co-fired with biomass</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 1A (without CO2 capture)</td>
<td>748.5</td>
<td>649.7</td>
<td>98.8</td>
<td>0.0</td>
<td>649.7</td>
<td>73.1</td>
<td>-290.7</td>
</tr>
<tr>
<td>Case 1B (with CO2 capture)</td>
<td>973.7</td>
<td>845.2</td>
<td>128.5</td>
<td>876.4</td>
<td>-31.3</td>
<td>754.1</td>
<td>390.3</td>
</tr>
<tr>
<td><strong>SC CFB boiler co-fired with biomass</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 2A (without CO2 capture)</td>
<td>748.2</td>
<td>649.4</td>
<td>98.8</td>
<td>0.0</td>
<td>649.4</td>
<td>73.4</td>
<td>-290.4</td>
</tr>
<tr>
<td>Case 2B (with CO2 capture)</td>
<td>999.0</td>
<td>867.1</td>
<td>131.9</td>
<td>899.1</td>
<td>-32.0</td>
<td>754.8</td>
<td>391.0</td>
</tr>
</tbody>
</table>
4 scenarios considered for the economical analysis:

- **Scenario 1**: the calculation of the cost of electricity does not include the revenues from the green certificates nor from the ETS mechanism.
- **Scenario 2**: the calculation of the cost of electricity only includes the revenues from the green certificates (50 €/MW).
- **Scenario 3**: the calculation of the cost of electricity only includes the revenues from the ETS mechanism (14€/t CO2).
- **Scenario 4**: the calculation of the cost of electricity includes both the revenues from the green certificates and from the ETS mechanism.
For Scenario 01 – No Consideration of ETS or Green Certificate Incentives (Case 1 and 2)
Economic summary

Electricity Production Cost, Cofiring cases

- Case 1a
- Case 1b
- Case 2a
- Case 2b

Scenarios:
- Scenario 1
- Scenario 2
- Scenario 3
- Scenario 4
Cost of ETS to Incentivise Biomass CCS (Case 1a and Case 1b)

- **COE without incentives**: COE @ ETS = 47.8 €/t CO2 & Green Cert. = 0 €/MWh
- **Levelised COE (€ / MWh)**:
  - COE without incentives
  - COE @ ETS = 47.8 €/t CO2 & Green Cert. = 0 €/MWh
  - COE @ ETS = 0 €/t CO2 & Green Cert. = 325 €/MWh
  - COE @ ETS = 47.8 €/t CO2 & Green Cert. = 312 €/MWh

Legend:
- blue: without CO2 capture
- red: with CO2 capture
Concluding Remarks

- There is potential for the use of biomass fired power plant with CO2 capture to be economically viable.
  - The economic viability of capturing CO2 from biomass fired or co-fired power plant could be dependent on the price of carbon / carbon tax that would incentivise the CO2 negative emissions.

- The study only evaluated the use of virgin wood as biomass feedstock – which is considered more expensive than indigenous low quality and more difficult burning biomass fuel. This should provide lower biomass fuel cost.

- The capture of CO2 from a biomass fired power plant using MEA Solvent, the following should be noted:
  - it should be expected that the need to treat larger volume of flue gas and a deeper removal of the SO2 and NOx in the flue gas would contribute to the reduction of the performance of the plant and increase in cost (CAPEX and OPEX).
  - This study only evaluated standard MEA solvent – therefore there are room for improvement in terms of cost and efficiency by using advance solvent.
Thank you

Email:  stanley.santos@ieaghhg.org
Website:  http://www.ieaghhg.org
Back Up Slides for Biomass Fired Power Plant
Case 3a- Biomass Fired CFB Boiler Power Plant w/o CO₂ capture

Unit 1000
Storage and handling of solids materials

Unit 2000
Boiler Island
- Biomass
- Fly & Bottom Ash
- IP Steam
- HP Steam
- IP Steam to RHT

Unit 3000
Steam Turbine & Preheating Line
- Cooling Water
- FeedWater
- Flue Gas to stack

Air

43
Case 3a – Power Plant Features

- **Power Plant Capacity**
  - Actual Net Power Output: 273 MWe

- **Boiler is a subcritical circulating fluidized bed unit which is commercially available / proven**

- **Boiler is fired with 100% Biomass; no pre-drying of biomass is included.**

- **Steam Conditions:**
  - 565°C HP (169 Bar) / 565°C RH (39 Bar)
Case 3a – Power Plant Features

• **External FGD and limestone injection in the combustion chamber are not required to meet SOx emission limits because of the low sulphur content in biomass.**

• **NOx is met by the CFB boiler. No SCR is necessary.**

• **A Plastic Heat Exchanger is installed downstream of the ID Fan to maximise heat recovery.**
Case 3b - Biomass Fired CFB Boiler Power Plant with CO₂ capture

Unit 1000
Coal & Ash Handling

Unit 2000
Boiler Island

Unit 3000
Steam Turbine & Preheating Line

Unit 5000
CO₂ Capture Plant

Unit 6000
CO₂ Compression & Drying

Limestone

Air

Biomass

Fly & Bottom Ash

IP Steam

HP Steam

IP Steam to RHT

Feedwater

Flue Gas

Clean Flue Gas

Cooling Water

CO₂ to Storage

Condensate Return

Condensate from Reboiler

Steam to Reboiler

Condensate

Cooling Water
Case 3b – Power Plant Features

- **Boiler is the same size with Case 3a. Due to extraction of low pressure steam from the steam turbine for the reboiler of the CO₂ capture plant – actual output is reduced.**

- **Power Plant Capacity**
  - Actual Net Power Output: ~169 MWe

- **No plastic heat exchanger installed downstream of the ID fan – due to the direct contact cooler of the CO₂ capture plant.**

- **In order to achieve the 10 ppm SOx level as required to reduce degradation of the MEA, limestone is injected into the boiler with Ca/S ratio of ~2.8. (This system requires demonstration.)**
Case 3b – Power Plant Features

- NOx emissions limit is met by the CFB. Level of NO\textsubscript{2} in the flue gas is considered tolerable by the MEA, thus there will be no SCR installed.
- N\textsubscript{2}O at the boiler outlet is expected to be low due to the slightly higher temperature in the bed. N\textsubscript{2}O is not expected to be removed by MEA. However the possibility of formation of stable salts from N\textsubscript{2}O should be investigated with the MEA suppliers.
Case 4a - Biomass Fired BFB Boiler Power Plant w/o CO₂ capture

Unit 1000
Storage and handling of solids materials

Air
Biomass
Fly & Bottom Ash

Unit 2000
Boiler Island

Flue Gas to stack
HP Steam
FeedWater

Unit 3000
Steam Turbine & Preheating Line

Cooling Water
Case 4a – Power Plant Features

- **Power Plant Capacity**
  - Actual Net Power Output: 75.8 MWe

- **Boiler is a subcritical bubbling fluidized bed unit which is commercially available / proven**

- **Boiler is fired with 100% Biomass; no pre-drying of biomass is included.**

- **Steam Conditions:**
  - 540°C HP (115 Bar) / No Steam Reheat
Case 4a – Power Plant Features

- External FGD and limestone injection in the combustion chamber are not required to meet SOx emission limits because of the low sulphur content in biomass.
- NOx is met by the BFB boiler. No SCR is necessary.
- No Plastic Heat Exchanger is installed downstream of the ID Fan due to performance increase does not justify the investment cost.
Case 4b - Biomass Fired BFB Boiler Power Plant with CO₂ capture

Unit 1000
Coal & Ash Handling

Unit 2000
Boiler Island
Air
Limestone
Coal
Fly & Bottom Ash
HP Steam
Feedwater
Flue Gas
Clean Flue Gas
Cooling Water
CO₂ to Storage

Unit 3000
Steam Turbine & Preheating Line

Unit 5000
CO₂ Capture Plant
Condensate from Reboiler
Steam to Reboiler
Condensate
➢ Condensate Return

Unit 6000
CO₂ Compression & Drying
Case 4b – Power Plant Features

- Boiler is the same size with Case 4a. Due to extraction of low pressure steam from the steam turbine for the reboiler of the CO$_2$ capture plant – actual output is reduced.

- **Power Plant Capacity**
  - Actual Net Power Output: ~49 Mwe

- In order to achieve the 10 ppm SOx level as required to reduce degradation of the MEA, limestone is injected into the boiler with Ca/S ratio of ~2.8. No external FGD is required.

- NOx emissions limit is met by the BFB. The NO2 level is considered tolerable to the MEA.

- N$_2$O is considered low – but would require the evaluation of MEA solvent supplier with regard to formation of stable salt.
# Performance of the Power Plants - Summary

<table>
<thead>
<tr>
<th>Case</th>
<th>Plant Type</th>
<th>Nominal Size</th>
<th>SCR</th>
<th>FGD</th>
<th>CO₂ Capture</th>
<th>Net Efficiency</th>
<th>Net output</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>SC PF boiler</td>
<td>500 MWe</td>
<td>Yes</td>
<td>Yes</td>
<td>0</td>
<td>44.8%</td>
<td>518.9 MWe</td>
</tr>
<tr>
<td>1b</td>
<td>SC PF boiler</td>
<td>500 MWe</td>
<td>Yes</td>
<td>Yes</td>
<td>90%</td>
<td>34.5%</td>
<td>398.9 MWe</td>
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<tr>
<td>2a</td>
<td>SC CFB boiler</td>
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<td>No</td>
<td>No</td>
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<td>45.1%</td>
<td>521.4 MWe</td>
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<tr>
<td>2b</td>
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<td>33.8%</td>
<td>390.5 MWe</td>
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<td>CFB boiler</td>
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<tr>
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<td>CFB boiler</td>
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<td>No</td>
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<td>25.8%</td>
<td>168.9 MWe</td>
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<td>4a</td>
<td>BFB boiler</td>
<td>75 MWe</td>
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<td>No</td>
<td>0</td>
<td>36.0%</td>
<td>75.8 MWe</td>
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<tr>
<td>4b</td>
<td>BFB boiler</td>
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<td>No</td>
<td>90%</td>
<td>23.2%</td>
<td>48.9 MWe</td>
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## Economic Analysis (cont’d)

### Estimated CAPEX

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<th>Case #</th>
<th>Total Investment cost</th>
<th>Specific Cost</th>
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<td></td>
<td>Million of Euro</td>
<td>Euro/kW</td>
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<td>Case # 1 a</td>
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<td>256.39</td>
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Consideration of ETS or Green Certificate Incentives (Case 3 and 4)
Electricity Production Cost, 100% biomass cases

- Case 3a
- Case 3b
- Case 4a
- Case 4b

Scenarios:
- Scenario 1
- Scenario 2
- Scenario 3
- Scenario 4
Cost of ETS to Incentivise Biomass CCS (Case 3a and Case 3b)