

IMPACT OF CO₂ SCRUBBING ON OVERALL POWER PLANT ARRANGEMENT AND PERFORMANCE

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ABSTRACT

Traditional amine-based CO₂ separation processes utilizing conventional solvents are very energy intensive when applied to coal-fired power plants and also susceptible to solvent degradation by oxygen, SO_x and NO₂ in the flue gas, resulting in drastically reduced plant efficiency and output as well as large operating cost.

Hitachi began post-combustion CO₂ capture R&D in the early 1990s, targeting coal-fired applications from the beginning. To address the above challenges of amine-based CCS for coal power the following approach was taken: 1) development of a flexible CO₂ capture process and the latest advanced amine-based solvent with long service life and low regeneration energy requirement; 2) design integration of steam cycle and CO₂ absorber - desorber process; 3) total plant re-optimization involving the boiler, turbine, air quality control system, and CCS system.

This paper provides a brief overview of Hitachi's post-combustion CO₂ capture R&D including solvent development, 1 MW_{th} pilot plant testing, and the new 5 MW_{th} mobile pilot plant test program. System optimization concepts for implementing CCS operation into an 800 MW power plant are discussed. Compared to a conventional approach with minimum system level integration, the optimized power plant with integrated CCS operation will have significantly higher efficiency and power output by reducing energy losses through applying the concepts discussed in this paper.

INTRODUCTION

In the United States about one half of the electricity is from coal. Worldwide coal contributes to over 40% of the electricity generation today and its share is expected to increase steadily over the coming decades. The continued dominance of coal in global energy structure and the growing concern of climate change necessitate accelerated development and deployment of new technologies for clean and efficient coal utilization. Coal-fired power plants with CO₂ capture and sequestration (CCS) are widely expected to be an important part of a sensible future technology portfolio to achieve overall global CO₂ reductions required for stabilizing atmospheric CO₂ concentration and global warming.

Amine-based CO₂ separation has been used since the 1930s for applications such as natural gas purification. It is a leading technology expected to be available commercially within the next decade to enable CCS for coal-fired power stations. However, traditional CO₂ capture process utilizing conventional amine solvents is very energy intensive and is also susceptible to solvent degradation by SO_x and NO₂ in coal-fired flue gas, resulting in large operating cost. According to recent DOE/NETL studies, MEA-based CCS will increase the cost of electricity (COE) of a new pulverized coal plant by 80-85% and reduce the net plant efficient by about 30%.

As a global technology and equipment provider for complete thermal power plants, Hitachi addresses the above challenges of amine-based CCS for coal power with the following approach: 1) development of a flexible CO₂ capture process and the latest advanced amine-based solvent with long service life and low regeneration energy requirement; 2) design integration of steam cycle and CO₂ absorber - desorber process; 3) total plant re-optimization involving the boiler, turbine, air quality

control system, and CCS system.

DEVELOPMENT OF HITACHI CO₂ CAPTURE TECHNOLOGY

CO₂ Scrubbing Process Overview

The Hitachi CO₂ scrubbing system is designed to achieve 90% capture with significant cost savings and efficiency improvement over current amine scrubbing technologies. The design approach considers the redundancy and reliability requirement according to power industry standards and the flexibility to allow plant owners to utilize common commercial amine solutions and advanced amine-based reagents.

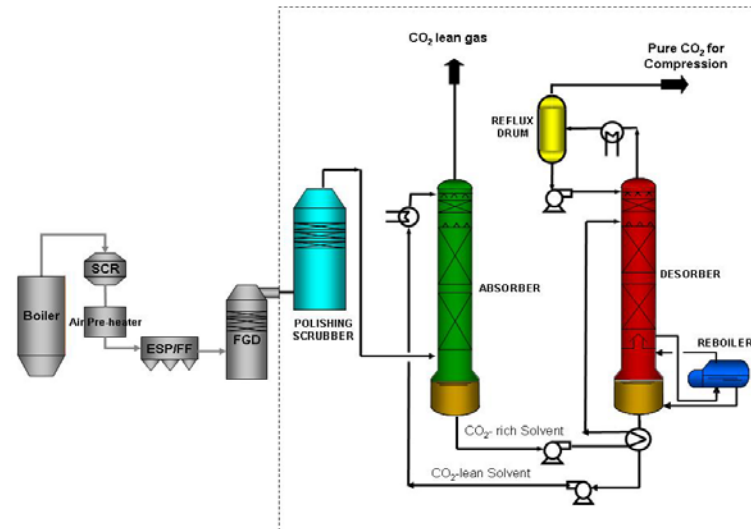


Figure 1. Process diagram of CO₂ capture system

The CO₂ capture system is based on proven process engineering principles. As shown in Figure 1, the main system components are a polishing scrubber (optional), an absorber, a desorber, a reboiler, and a reclaiming unit (not shown). Flue gas from the power plant or industrial facility is first sent to the polishing scrubber to reduce SO₂ and SO₃ to below about 10 ppm (combined), as well as to cool the flue gas to 40-60°C (100-140°F) range for maximum CO₂ capture in the absorber. Caustic soda (NaOH) solution is used to remove SO_x and therefore minimize formation of heat-stable salts (HSS) in the downstream absorber-desorber loop. The clean and cool flue gas leaving the polishing scrubber enters the packed bed absorber where it reacts with the amine-based solvent. Counter-current flow through two or more stages of structured packing maximizes contacting surface area and mass transfer. Solvent solution is injected into the top and collected from the bottom of the packing layers. Because CO₂ absorption is an exothermic reaction, inter-stage cooling heat exchangers are used to maintain the optimum absorber temperature. CO₂-depleted flue gas leaving the top of the absorber is vented to the stack. The CO₂-rich solution leaving the bottom of the absorber is sent to the desorber via a cross heat exchanger where it gets heated. In the packed-bed desorber, pure CO₂ gas is stripped away from the CO₂-rich solution by contacting it with steam in a counter current direction. A part of the CO₂-lean solution from the bottom of the desorber circulates through a reboiler where auxiliary steam is utilized to partially vaporize the amine solution which, upon returning to the desorber provides the heat needed for amine regeneration to release CO₂. Regenerated solvent is re-sent to the absorber after it gets cooled in the cross heat exchanger. Water washing nozzles and mist eliminators are located at the top of both the absorber and desorber to prevent entrained liquid droplets from leaving the system. A reclaiming unit is operated in batch mode when needed, to control the HSS level in the system. The reclaiming unit extracts a stream of amine solution, vaporizes it with the heat from auxiliary steam, and returns the vapor to the desorber, while rejecting the HSS from the bottom.

Process and Solvent Development

Hitachi started post-combustion CO₂ capture R&D specifically for coal-fired applications in the early 1990s, when the first bench-scale and pilot test programs were initiated. Since then, the company has been continually improving process design and the technology for full-scale power plant applications.

Bench-scale studies (Figure 2) with simulated flue gas have been performed regularly to screen and identify promising absorbents and additives for maximum CO₂ removal efficiencies while keeping solvent degradation and energy consumption low.

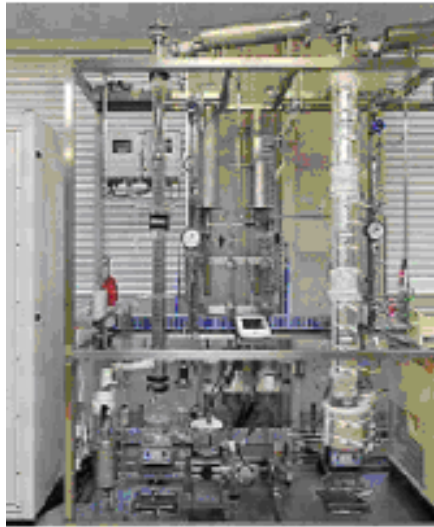


Figure 2. Bench-scale test rig

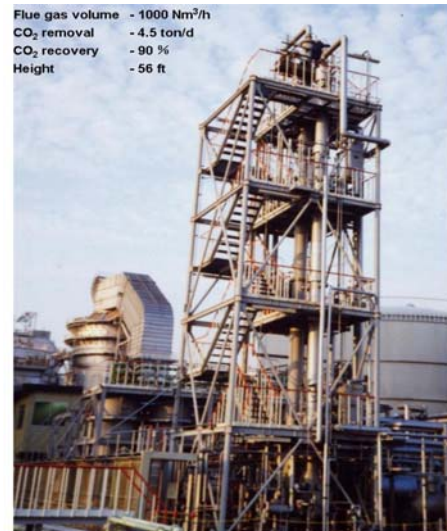


Figure 3. Pilot plant at Yokosuka

Figure 3 shows Hitachi's first CO₂ capture pilot plant built at Yokosuka Thermal Power Plant Unit 2 in cooperation with Tokyo Electric Power Corporation (TEPCO) in Japan. The slipstream test facility treated 1000 m³N/h (620 scfm) of flue gas for CO₂ removal.

During a two-year demonstration period, five solvent solutions were tested, including a commercial MEA as benchmark and three proprietary solvent formulations. The test for H3, Hitachi's proprietary solvent formulation and the best performing solution of the five, lasted 2000 hours under various operating conditions and generated a large database of solvent and system behavior.

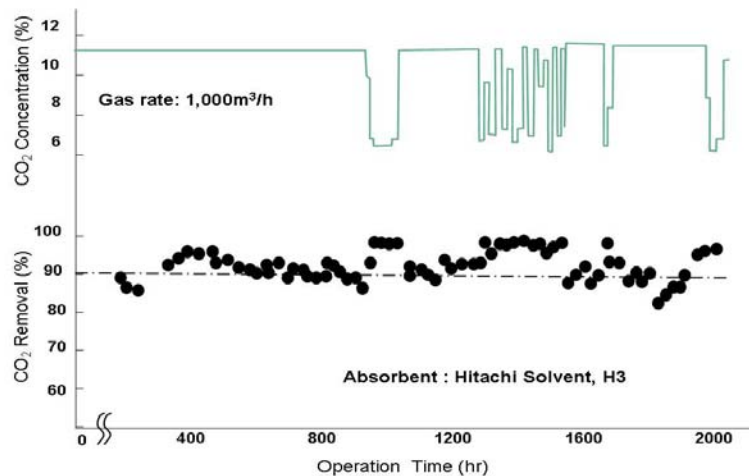


Figure 4. Long-term pilot testing of H3 solvent under various inlet CO₂ concentrations

Figure 4 shows that in over 2000 hours of testing under various loads and inlet CO₂ concentrations, the H3 solvent consistently achieved greater than 80% CO₂ removal with the average well above 90%. H3 has specific regeneration energy of 2800 kJ / kg CO₂ which is the best among tested solvents and much lower than commercial MEA. It also has high absorption capacity, thus requiring lower liquid-to-gas ratio for 90% capture than that for MEA and resulting in significant operating cost savings. Hitachi continues the refinement of the proprietary solvent blends in its laboratories. The new solvent formulations are also being tested and compared with other commercial or near commercial solvents by independent institutions in Japan and USA.

Large Mobile Pilot Plant

Based on earlier experience in Japan, Hitachi Power Europe GmbH, in cooperation with utility partners Electrabel / GDF Suez and E.ON., is building a large mobile pilot plant for the separation of carbon dioxide from coal-fired power plant flue gases. The plant is used to generate data for the development of design concepts for both new power plant integrated with CCS or retrofit of a carbon dioxide separation plant in existing power stations.

Figure 5 shows the general arrangement of the mobile pilot plant. The plant components are built into transportable segments equivalent to overseas containers.

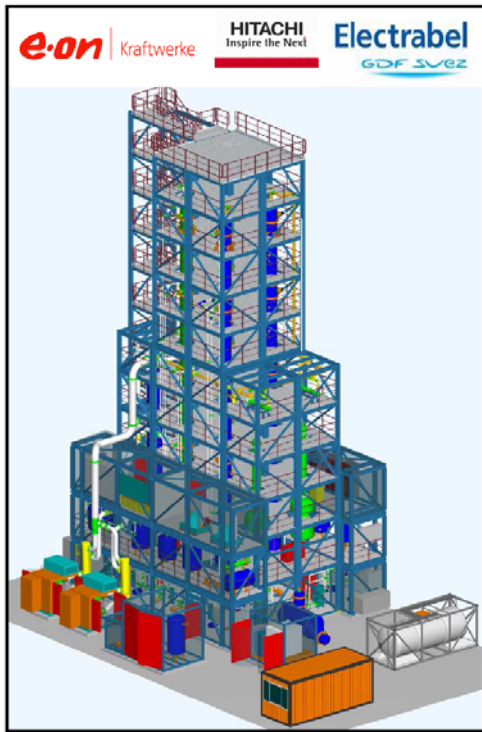


Figure 5. Pilot plant arrangement

These preinstalled segments, shown in Figure 6, are erected at the site of the host power station and connected to a slipstream of flue gas after the plant's FGD unit. The pilot plant is designed to process a flue gas volume flow of approximately 5000 Nm³/h corresponding to 5 MW_{th}. The auxiliaries and steam needed for the operation are supplied by the host power plant.



Figure 6. Mobile pilot plant segments

Figure 7 is the process schematic of the pilot plant. Flue gases after the wet FGD of a typical existing power plant in Europe still have 200 mg/Nm³ SO₂ (~ 0.15 lb/MMBtu) and about 10 mg/Nm³ SO₃ (~0.08 lb/MMBtu). For further cleaning, a caustic soda pre-scrubber is installed upstream of the two carbon dioxide absorbers. Behind the pre-scrubber, the flue gas flow is uniformly distributed to two trains of absorber- desorber system with amine solution as the scrubbing reagent for CO₂. The two train design allows three different operation configurations :

- Parallel operation 2 x 2500 Nm³/h,
- Single line operation 1 x 2500 Nm³/h,
- Serial operation of two absorbers followed by one desorber.

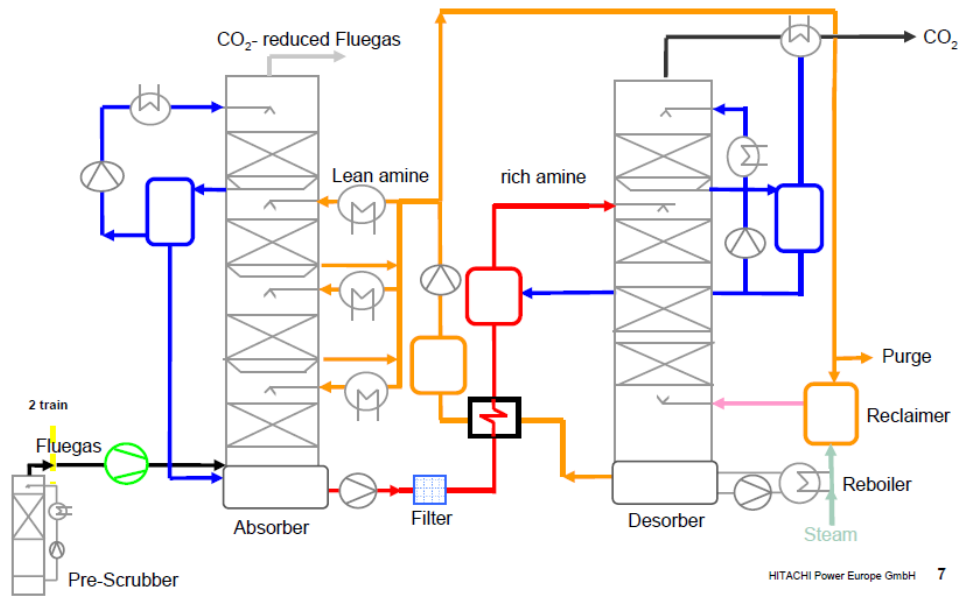


Figure 7. Flow sheet of the pilot plant

Essentially, the serial operation of both trains has the following reasons:

- Doubling the packing height of the absorber:
Each absorber is provided with 3 packing levels. Should it be found, for example, that these packing levels are not sufficient to ensure a certain degree of separation, the second absorber can be added with additional packing height.
- Utilization of the downstream absorber as an additional washing stage:
A washing stage is installed at the top of each absorber. In case the existing washing stage is not sufficient to reduce solvent carryover to desirable levels, each washing stage can be optionally enlarged with another packing unit. If further reduction in emissions is necessary, the second absorber in series arrangement can function as an additional washing stage.

The ability to arrange the pilot plant in three configurations offers maximum flexibility. The pilot plant thus will be able to run under a very wide range of operating conditions such as process gas flow, residence time, CO₂ removal rate, allowable solvent carryover, etc, and produce reliable data for the scale-up to full size plants.

The primary objective of the pilot program is to investigate the lowest energy demand and to determine design criteria for the optimization of capital investment and operating costs. Besides this the design data to minimize the environmental impact of the CO₂ scrubbing system will be of great interest. The pilot plant will be fully equipped with an on-line monitoring system to continuously measure trace emissions of solvent as well as some of the degradation products. In addition, periodic campaigns will be conducted for the complete measurement of degradation product emissions.

The main parameters for testing will be:

- Investigation of the effect of solvent inter-cooling,
- Operation with different solvents,
- Influence of enhanced HSS formation by decreasing pre-scrubber efficiency,
- Investigation of increased flue gas temperature by decreasing pre-scrubber efficiency,
- Operation with different washing stage efficiencies to investigate the influence on the emissions.

Scaling up to Full Size Plant

The pilot plant has an absorber diameter of about 1 m. Currently, absorbers with diameters up to 12 m have been applied in the chemical industry. For an 800 MW plant a single absorber would need a diameter of roughly 19 m. There is a need for intermediate steps from pilot plant sizes to 800 MW_{el} full size plants. Figure 8 shows possible steps in size from a pilot plant to full size equipment.

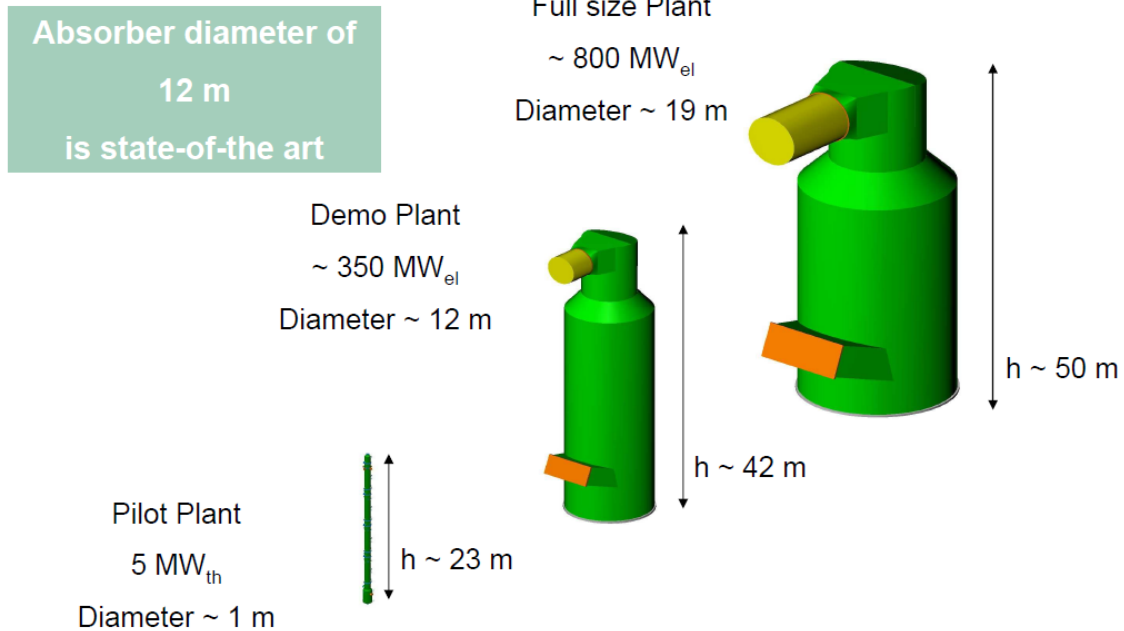


Figure 8. Steps from pilot plant to full size plant

INTEGRATING CO₂ CAPTURE INTO A POWER PLANT

The Reference Plant

A state-of-the-art, supercritical pulverized coal-fired power station currently under planning stage is selected as the reference case for the plant integration study. As shown in Figure 9, it has a single reheat steam cycle with a main steam temperature of 596°C (1105°F) and reheat temperature of 608°C (1126°F). The plant with direct sea water cooling will have a net efficiency of about 46% on a lower heating value (LHV) basis. This plant is representative of the 600°C class supercritical PC power plants that have been widely deployed in Europe and Asia.

Currently, the worldwide average of power plant net efficiency is about 30% LHV, corresponding to a carbon intensity of approximately 1100 g CO₂/kWh. The 600°C class plants, considered as the best available technology (BAT) in Europe, emit about 720 g CO₂/kWh. The next generation advanced ultrasupercritical power plant under development by Hitachi and others, will feature a 700°C (1292°F) steam cycle and reach a net efficiency in the 50% LHV range, further reducing carbon emissions to about 660 g CO₂ / kWh.

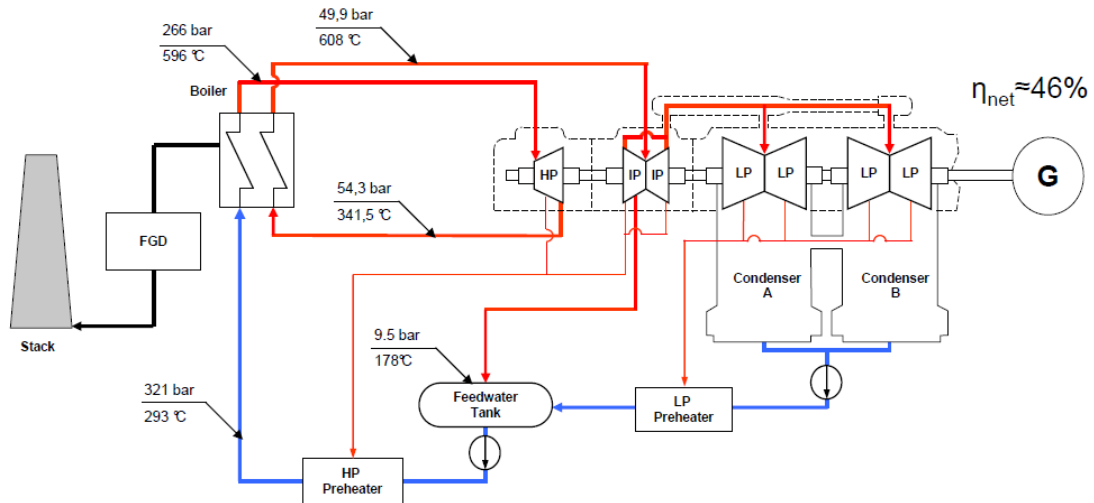


Figure 9. Heat balance diagram of an 800 MW state-of-the-art power plant

Requirements of CCS integration

Implementation of CO₂ scrubbing into a power plant poses enormous challenges to the design of the power plant itself and the post combustion capturing system respectively. Several interfaces have to be considered and optimized which necessitate modifications to the plant components. Figure 10 shows these main interfaces.

Aside from using the best solvent with the lowest regeneration energy requirement, the overall net plant efficiency of a power plant with CCS can be maximized by optimizing the integration of available heat sources and heat sinks across the entire plant system including the CCS scope. In addition to process and electrical interfaces, the required space for the carbon capture plant can be a problem especially for retrofits into existing power plants. The minimization of the required space is a major task for both process design and arrangement planning.

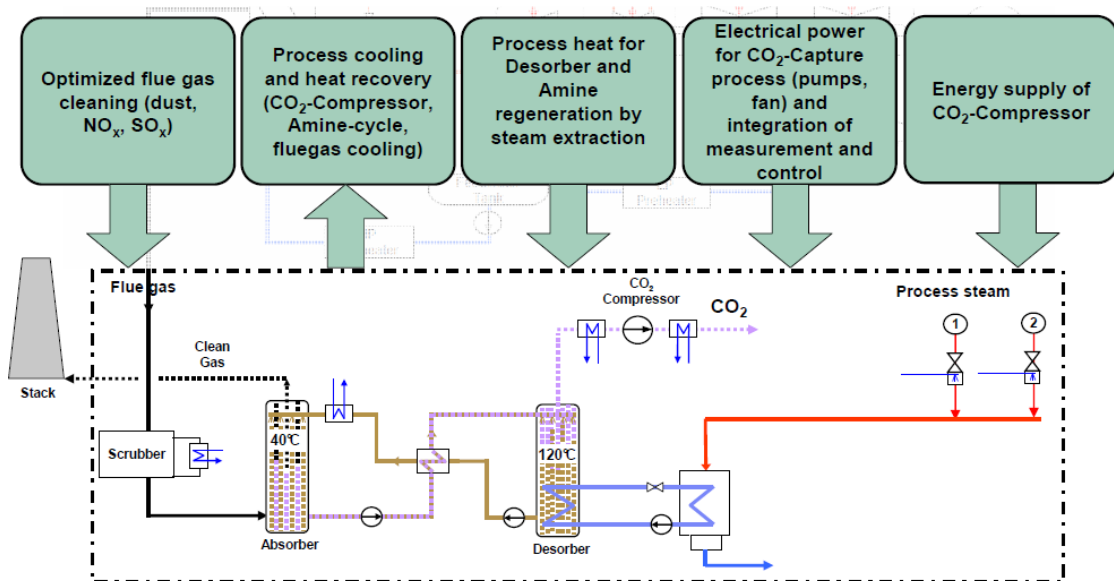


Figure 10. Interfaces between a post combustion capturing system and a power plant

Optimization of Flue Gas Cleaning System

Amine based solvent solutions are known to react readily with SO₂ and SO₃, resulting in the formation of heat stable salts and amine degradation. Generally, in the flue gas entering the CO₂ absorber, the combined SO₂ and SO₃ concentration need to be 10 ppm or less to avoid excessive solvent loss in the CO₂ capturing process. To reduce SOx emissions to this level, several approaches discussed below can be considered.

Additional Polishing Scrubber vs Single-Stage Wet FGD

For plants with older FGD units and high outlet flue gas SOx concentration, a separate polishing scrubber, also called “pre-scrubber” for the CO₂ absorber, should be considered. For existing FGD with very low SOx emissions, further reduction of SOx to the level required by CO₂ scrubbing may be achieved by upgrading FGD internals, adding spray level(s) to the existing unit, and/or applying organic acid to the FGD slurry as pH buffer to enhance SO₂ removal performance.

Although the vast majority of existing dry or wet FGDs in the world today operate with outlet SO₂ well above 10 ppm, Hitachi’s open spray tower wet FGD technology with its CFD-guided design of high spray flux and variable spray density to prevent local flue gas sneakage, is capable of achieving single digit ppm SO₂. In fact six (6) Hitachi wet FGD units, including one unit recently commissioned in the United States, are in commercial operation with SO₂ removal efficiencies well above 99% and FGD outlet SO₂ well below 10 ppm. Five of these units have outlet SO₂ concentrations in the low single digits. These units were designed for ultra-low SO₂, not for CCS, because of stringent emissions regulations at these plant locations which are often due to the very high population density in the nearby areas. These “single digit” FGD units are treating flue gas from fuels with very low to very high sulfur content, including two units in Japan treating flue gas from high sulfur petroleum coke.

The “single digit” wet FGDs are designed with large numbers of spray levels and high liquid-to-gas ratios. Therefore, they have higher capital and operating costs than ordinary FGDs. However, for new plants or existing plants building a new FGD, a single stage wet FGD can be more advantageous than a combination of a primary FGD and a polishing FGD.

Clean Energy Recuperator (CER)

SO₃ can be a significant contributor to total SOx emission, especially for plants burning higher sulfur coals. As flue gas enters the FGD absorber, SO₃ condenses into fine mists which are only partially captured in the wet FGD. One way to achieve high SO₃ removal rate is by adding a wet ESP downstream of the FGD absorber. Alternately, hydrated lime, or sodium based sorbent in either powder or solution form can be injected upstream of the dust collector to capture SO₃.

CER is a technology developed by Hitachi that can effectively remove SO₃ and can contribute significantly to efficiency improvement of a power plant through recovery of flue gas waste heat. CER is derived from Hitachi’s patented high dust Gas-Gas-Heater (GGH) technology which has been successfully applied to five large supercritical coal-fired power plants in Japan. In the United States, CER has also been demonstrated at a slipstream test facility at Ameren’s Duck Creek Power Station burning US bituminous coals. Shown in Figure 11 as a part of the air quality control system with a wet FGD, the CER heat recovery module is located between the air preheater and the dust collecting device (ESP or Fabric Filter). The CER is a finned tube heat exchanger with water as the cooling medium. It cools the flue gas from more than 150°C (300°F) to about 88°C (190°F) and recovers a large amount of low grade energy. When integrated for turbine condensate heating, this recovered energy can reduce the power plant heat rate by about 1%. This low grade heat can also be used as a heat source for the CO₂ desorber to avoid a part of auxiliary steam (energy) consumption.

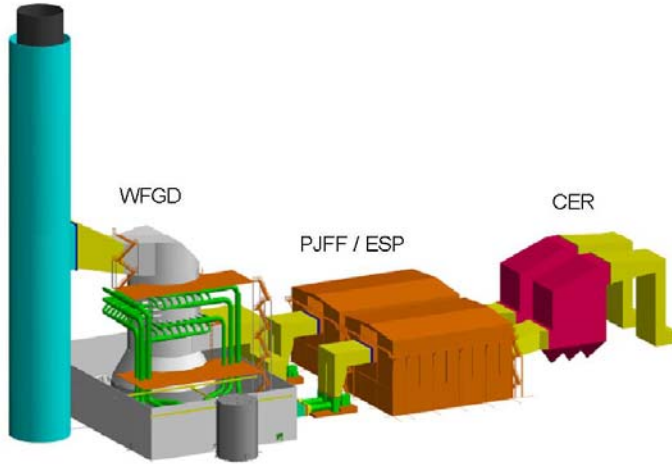


Figure 11. Hitachi Clean Energy Recuperator

Due to its operation in high ash environment and the deep cooling of flue gas, the CER removes almost all SO_3 in the flue gas. By cooling down the flue gas indirectly, water consumption for the wet FGD can be reduced by about 50%.

The selection of AQCS configuration will be on a case-by-case basis, depending on factors such as fuel sulfur content, desired level of SO_x entering the CO_2 absorber, and costs for various reagents. With a rational combination of the technology options discussed above, the performance of the air quality control system will certainly meet

the requirements for CCS technology without adverse effects on other parts of a coal fired power plant.

Process Integration of CO_2 Capture System

Conventional Approach

The conventional approach does not provide maximum integration of the CCS system with the steam cycle. Instead the CCS system and the steam cycle are optimized independently. The energy needed for the regeneration of the CO_2 rich solvent is the key issue for the performance and efficiency losses. Most of this energy will be provided by steam extraction from the power plant. A conventional approach for the steam extraction from the water steam cycle is shown in Figure 12. The steam for desorption is extracted at the hot or cold reheat steam line (1) or the crossover pipe (2) between the IP and LP turbine. As a result, very high losses in efficiency cannot be avoided.

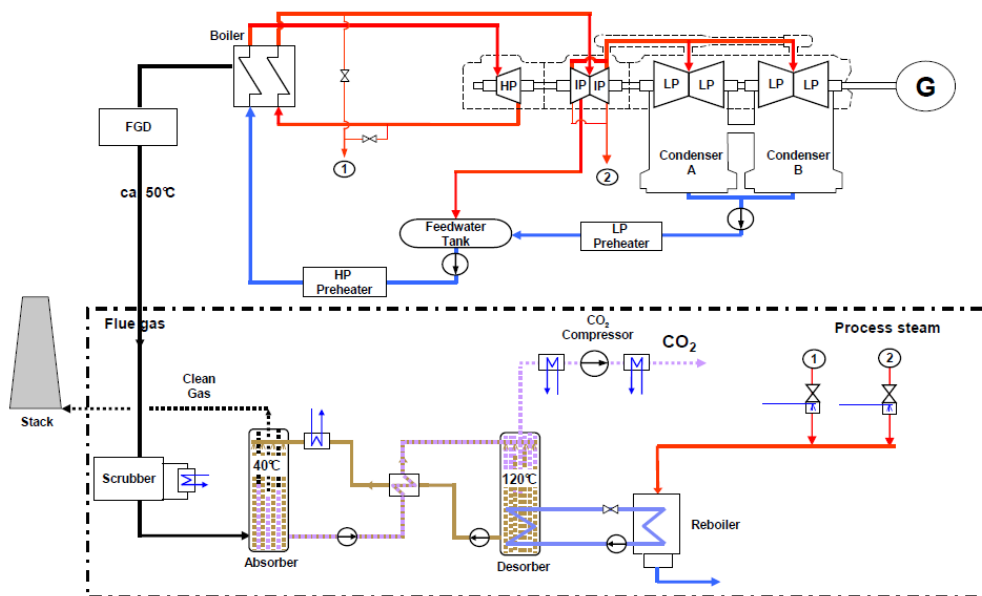


Figure 12. Water-steam cycle of a power plant with CCS process integration

This conventional approach for CO₂ capture process implementation will have a power plant net efficiency loss of about 13.1% points if MEA with a specific regeneration heat 3600 kJ/kgCO₂ is used. If the advanced solvent H3 (2800 kJ/kgCO₂) is used, the loss will be 9.1% points. An additional loss of efficiency of 2.8% points due to CO₂ compression has to be added, assuming that the CO₂ is compressed to 200 bar at 30 °C (2900 psi at 80 °F). The basis for the efficiency comparison is the reference plant described earlier. When firing a hard coal, the plant has a net efficiency of 46.9 %LHV, without CCS.

Advanced Approach

Steam cycle modifications

Due to the enormous efficiency losses of the conventional approach, a better way to integrate the post-combustion capture plant into the power plant must be found. To increase the efficiency, an optimization of the plant overall process is needed, i.e., all heat sinks of the CCS system needs to be introduced at an optimum location of the steam cycle so that no energy is wasted. This can be accomplished by integration of the condensate and the cooling water from the CCS process into the water steam cycle as well as the steam extraction from the steam turbine for the reboiler heating. Figure 13 shows an optimized water steam cycle of a power plant.

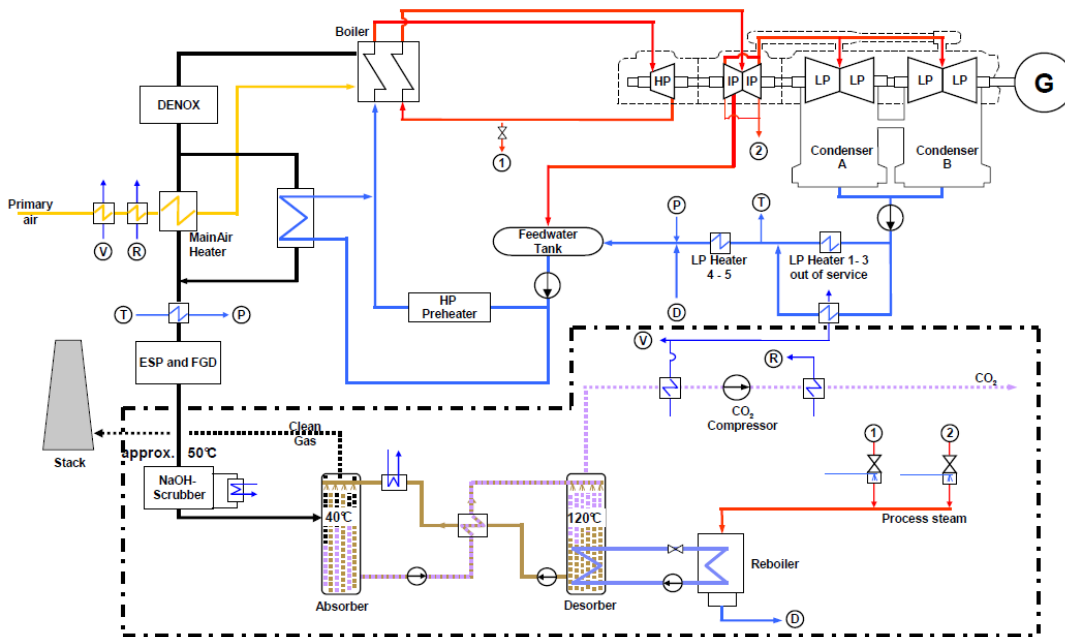


Figure 13. Optimized water-steam cycle of a power plant with CCS process integration

The modifications of the water steam cycle are as follows:

- The condensate from the reboiler heating steam is reintegrated into the main condensate line downstream of the condensate preheater No. 5.
- The CCS process has a large demand for cooling water capacity. A part of the heat transferred by the CCS system to the cooling water can be recovered to warm up the condensate upstream of the feedwater tank/deaerator. As a result, the LP heaters No. 1-3 can be bypassed and unloaded, which results in increased steam cycle efficiency.
- Another possibility is a modification of the air preheating and flue gas system which allows the use of the waste heat of the CCS process to warm up the feedwater as well as main

condensate. A part of the waste heat from the CO₂ cooling at the desorber outlet (V) and the waste heat of the CO₂ compressor (R) are used for air preheating before entering the main air heater. Since these waste heats are used for air preheating, a part of the flue gas heat can be shifted to the feedwater line by using a heat exchanger in parallel to the main air heater. The remaining heat amount of the flue gas downstream the main air heater can be used for main condensate preheating (P).

- The thermodynamically preferred location for the steam extraction is the crossover pipe (2) between the IP- and LP- steam turbine. This extraction can be partially switched to the cold reheat steam line (1) to increase the pressure of the extraction steam, if necessary.

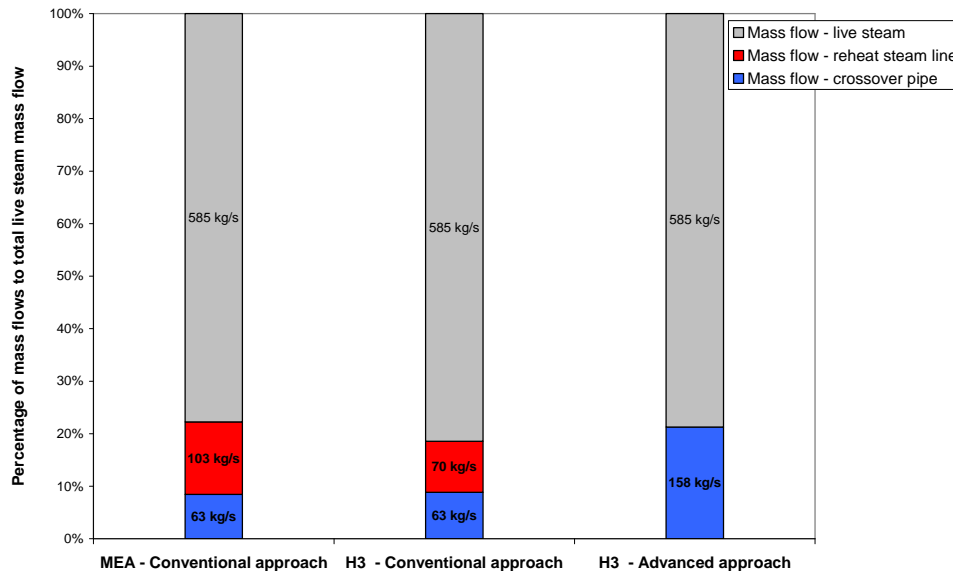


Figure 14. Split of steam extraction

Figure 14 shows the split of the steam extraction. In the conventional approach, the main part of the needed steam is extracted at the reheat steam line (see [1] in Figure 12). This steam has a high caloric level (~ 3700 kJ/kg); therefore an extraction at this location results into a high loss of net efficiency. In the advanced approach, the steam is completely extracted at the crossover pipe between the IP and LP steam turbine. The steam enthalpy at this location is approximately 20 % lower (~ 3000 kJ/kg) than the enthalpy of the steam in the reheat steam line. Therefore, with the extraction at this location the energy losses are smaller.

Steam turbine modifications

The large amount of heat for the regeneration makes modifications to the standard steam turbine design necessary. For 90% CO₂ separation about 25-30% of the live steam flow or approximately 60% of the exhaust steam flow has to be extracted. Depending on the possibilities for steam extraction at the steam turbine the following design considerations are required:

Regardless whether the steam is extracted from the crossover line between IP- and LP-steam turbines, the reheat steam line or both, the blades of the HP- and IP-turbine must be designed for the increased pressure/enthalpy drop across all stages. The casted outer casing of the IP- turbine must be designed according to the increased mass flow of the steam extraction for the CCS process. The LP turbine must be able to accommodate large flow variations due to the process steam extractions (in some cases, the steam turbine will also have to be able to continue operation with no process steam extractions, when the CCS is not in operation.) The length of the last stage blades (LSB) of the LP- turbines must be optimized according to the new exhaust steam flow requirement, (which is less with CCS). Operation with CCS will require shorter LSBs to avoid excessive exhaust losses due to

ventilation and low load operation. Optionally a crossover valve between the IP- and LP-turbines can be used to reach the required steam pressure for the supply of the heat quantity for the CCS process. The crossover valve maintains a constant steam pressure on IP- turbine outlet and the extraction stub, which would minimize the modifications required for HP and IP turbine design. However, the crossover valve itself creates its own design challenges that need to be considered and moreover, throttling losses of the crossover valve will decrease the cycle efficiency.

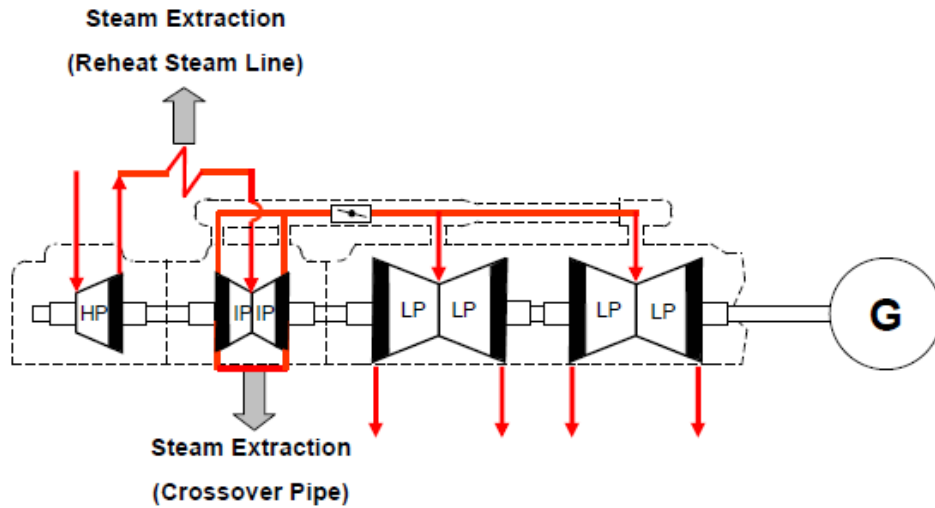


Figure 15. Modifications of the steam turbine

The above mentioned design requirements can be considered in the planning phase for new power plants. In case of existing plants, the required modifications at the steam turbine for the steam extraction might be executed with a turbine retrofit.

Impact on net plant efficiency

As a result of the modifications for the water-steam cycle and the steam turbine, the loss of net efficiency is reduced to only 7.8 % points for H3 and 7.5 % points for next generation solvent (NGS) with regeneration energy of 2500 kJ/kg CO₂ (including CO₂ compression to 200 bar). The efficiency loss for the conventional approach discussed earlier is also plotted in Figure 16 for comparison.

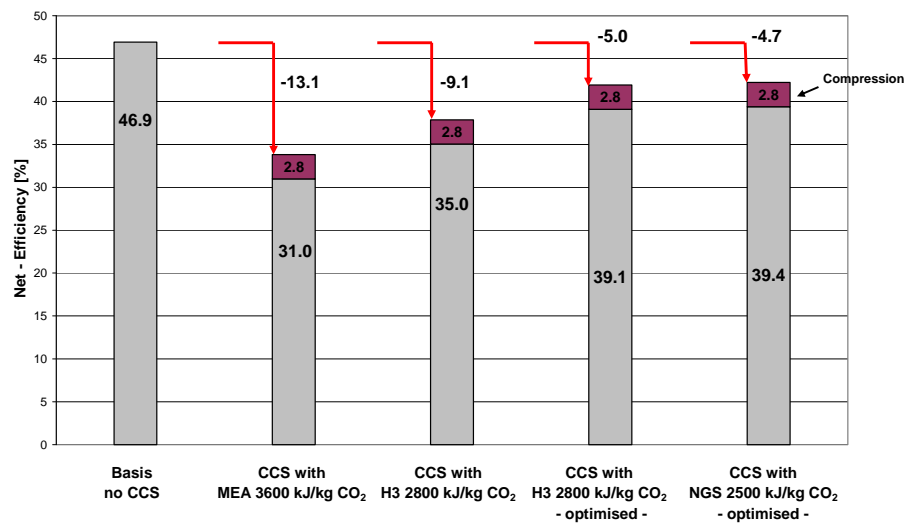


Figure 16. Results of optimization

Arrangement of the Power Plant with CCS

The area needed for the CCS plant depends partly on the maximum size of the absorbers and desorbers. The state-of-the-art absorber diameter of 12 m means that the flue gas of a 350 MW_{el} demo size plant can be treated. Therefore the minimum number of trains required for an 800 MW_{el} full size plant is three. With further development of large single absorber diameters the required space can be reduced by using fewer absorbers and/or desorbers. In Figure 17 possible arrangements with two to three absorbers and one to three desorbers are shown. With these arrangements the installation area can be reduced by up to 25% from the base arrangement with 3 absorber and 3 desorbers. Figure 18 shows the arrangement of the CO₂ capture island with the optimized design.

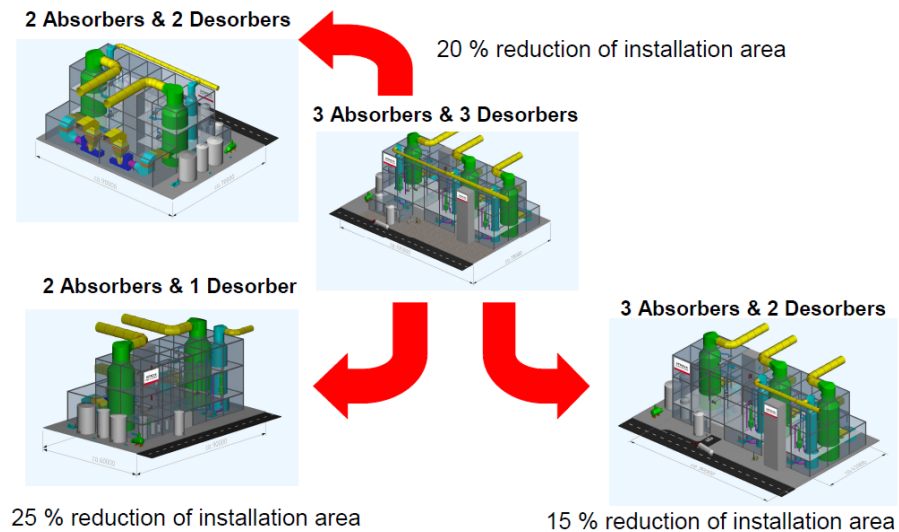


Figure 17. Possibilities for the reduction of installation area

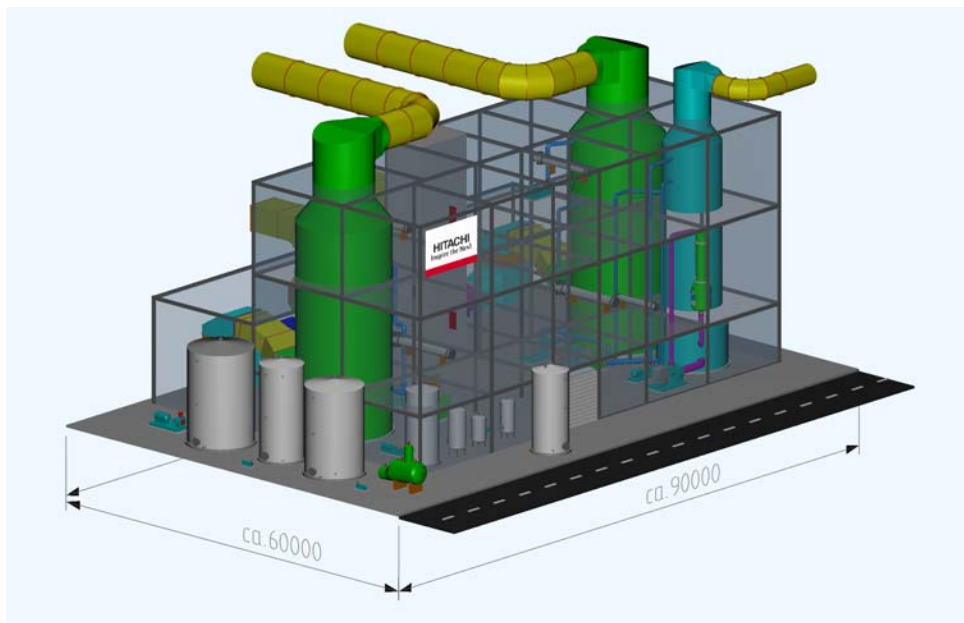


Figure 18. Arrangement for an 800MW with two absorbers and one desorber

In Figure 19 a layout plan for the integrated power plant with a post-combustion capture system is shown. The footprint of the CO₂ capture island is about 60 m x 90 m (197 ft x 295 ft) for the 800 MW electric plant, when using 2 absorbers and 1 desorber.

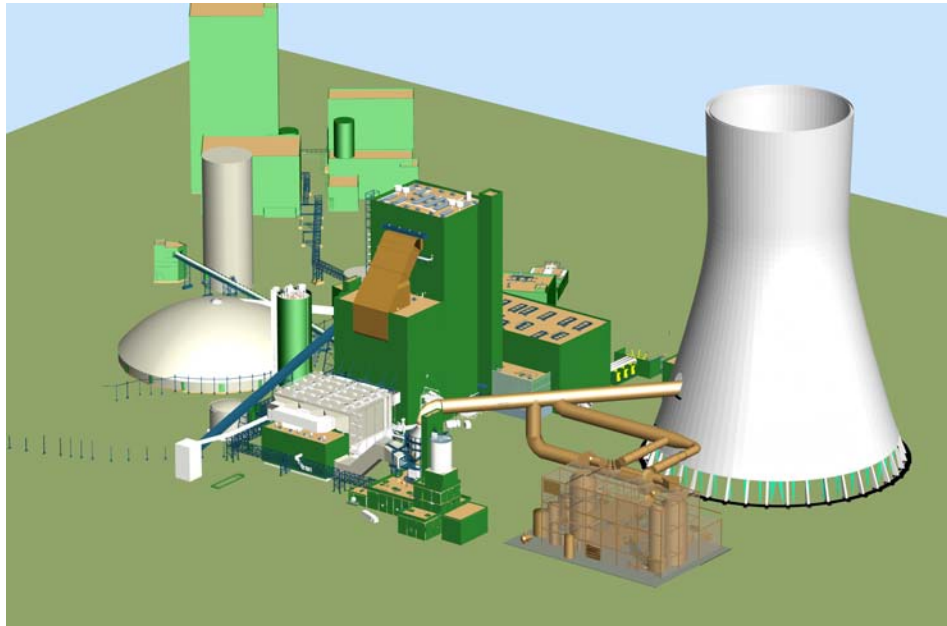


Figure 19. Integration of a post combustion capture plant into a power plant station

SUMMARY

For application of post-combustion CO₂ capture at a coal-fired power plant, several technical challenges have to be solved. Use of advanced amine-based solvent can alleviate solvent loss due to impurities in the flue gas. In addition, flue gas cleaning system upstream of the CO₂ absorber has to be optimized. Hitachi has developed an advanced FGD technology capable of ultra-low SO₂ emission levels. A polishing scrubber can also be used when necessary. The Clean Energy Recuperator can effectively remove SO₃ and improve plant efficiency by recovering flue gas waste heat. With these alternatives, SO_x outlet concentrations of less than 10 ppm will be achievable for new plant or retrofit applications. Further reduction of amine loss can be realized by using a solvent reclaiming process. With these technical measures the power plant operator will be in a position to find customized and specific optimum system configuration and operating practices.

Hitachi is building a large mobile pilot plant in cooperation with Electrabel S.A./GDF Suez and E.ON. The pilot plant has a flexible two train, three configuration design that can be operated under a very wide range of operating conditions such as gas flow, residence time, CO₂ removal rate, and allowable solvent carryover. The flexible design also will be able to achieve desirable amine emission levels to meet existing or anticipated regulatory requirements. This large pilot test program will provide valuable data to support the design of demonstration and commercial plants.

A primary target of system level optimization is to reduce efficiency loss, through an approach with three essential elements. The first is the use of the latest solvent with low regeneration energy and resistance to degradation, and continuing development of next generation solvent with further improved performance. The second is rational redesign and modifications of the steam turbine to supply the heat for CCS with minimum loss of electricity output. The third integration area involves boiler heat recovery, combustion air preheating, feedwater heating, and turbine condensate preheating in the context of CCS implementation. By applying these measures, plant efficiency loss can be reduced to less than 5% points (excluding CO₂ compression). Hitachi is currently undertaking extensive global development and demonstration programs to improve basic technologies for CO₂ scrubbing and to accelerate commercialization of CCS for coal-fired power plants worldwide.