

Carbon Capture and Storage for Enhanced Oil Recovery: Integration and Optimization of a Post-Combustion CO₂-Capture Facility at a Power Plant in Abu Dhabi

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Summary

Masdar has initiated the Abu Dhabi Carbon-Capture and -Storage Project, with the objective to develop a carbon-capture network in Abu Dhabi capable of creating large reductions of carbon dioxide (CO₂) emissions and with the capacity to increase oil recovery by use of CO₂ for enhanced oil recovery (EOR). Because Siemens (henceforth referred to as the Technology Owner) has developed, tested, and piloted a proprietary post-combustion CO₂-capture technology (PostCap™) for the removal of CO₂ from the flue gas of coal- and gas-fired power plants suitable for the project, both parties decided to cooperate in executing a front-end engineering and design (FEED) study. The technology is based on an aqueous amino-acid-salt solution.

The Technology Owner and Masdar have completed a FEED study for capturing 1,800,000 tons of CO₂ annually from a natural-gas-fired power plant in Abu Dhabi by application of the PostCap™ technology.

Various opportunities and challenges were encountered during the design of the retrofit capture plant. Challenges were often specific to the region, including local climate, water availability, and flue-gas quality. Design and optimization of the plant were influenced by local energy and labor prices. Further opportunities included integration with the power plant and with a local industrial facility. The power plant had to supply the capture plant with steam and power without reducing the original electricity-production capacity. To accomplish this, several heat- and power-integration concepts were evaluated with respect to their feasibility, including the application of a backpressure steam turbine and the retrofit of a simple-cycle gas turbine to combined-cycle gas turbine.

Various cooling options were considered in view of climate and resource challenges. Cooling water had to be extracted from a reflux stream produced by an adjacent industrial facility.

Drawing on the results of the FEED study, this paper presents the manner in which PostCap™ technology can be applied for capturing CO₂ at a power plant in Abu Dhabi for the purpose of EOR, while satisfying specific local needs, and the way utility supply and power plant integration can be facilitated.

Introduction

The world's continuously rising demand for electricity is caused by a rapidly growing population and furthermore by a progressing electrification of the world. Besides an increasing capability of renewable sources for electricity and an adherence to nuclear power,

fossil-fueled power plants remain the backbone of power generation (IEA 2013b). To satisfy this demand, numerous new-builds are planned all around the world. Keeping the temperature-increase goal of 2°C for global warming in mind, this development calls for mature carbon-capture techniques that reduce the climate impact of fossil-fueled power stations.

Among the most-advanced and -engineered solutions for carbon dioxide (CO₂) capture are post-combustion absorption/desorption processes, usually with aqueous amine solutions as solvents (Blauwhoff et al. 1984; Kohl and Nielsen 1997; Rinker et al. 2000; da Silva and Svendsen 2004). The Technology Owner, as a modification, has developed the PostCap™ (post-combustion carbon-capture) process by use of an amino acid salt (AAS) dissolved in water as solvent. AASs are described by various authors as a promising alternative to conventional amines (e.g., Rochelle et al. 2001; van Holst et al. 2006; Abu Zhara 2009; Feron and Puxty 2011; Majchrowicz 2014). The advantages are that AASs are salts and are therefore nonvolatile, which eliminates the threat of inhalation and solvent loss through gas phase. Moreover, many AASs are naturally occurring substances that are nontoxic, nonexplosive, odorless, and biodegradable. This leads to exceptional benefits for the operability of AAS-based CO₂-capture units.

Capturing CO₂ for climate-related reasons, however, is only one side of the story. The use of CO₂ as a valuable product is one step forward. The yield from oil fields can be increased considerably by enhanced oil recovery (EOR), a tertiary method of injecting CO₂ underground with high pressure and thus extracting oil. The oil/CO₂ mixture reaching ground level can be flashed off and separated by well-established technologies; the CO₂ will be reinjected and will remain underground after a certain number of turnovers. Studies name a potential worldwide demand of 260 to 310 gigatons (Gt) of CO₂ for EOR (Van Leeuwen 2011), which could even be extended up to 460 Gt by application to smaller oil fields (Godec 2011). The CO₂ will be, finally, stored underground. The resulting oil yield is given in the studies to be approximately 880 to 1,050 billion bbl of oil (Van Leeuwen 2011) or even more than 1,500 billion bbl (Godec 2011). Near-term projections forecast an annual use of 124 megatons (Mt) of CO₂ in the US only by 2020 (Wallace and Kuuskraa 2014).

Aiming both at climate and economic benefits, Masdar has initiated the Abu Dhabi Carbon-Capture, -Usage, and -Storage Studies, with the objective to develop a carbon-capture network in Abu Dhabi capable of providing large reductions of CO₂ emissions while providing CO₂ for EOR purposes. Phase 1 of the project, the purification and transport of approximately 800,000 tons of CO₂ annually emitted from a steelmaking process, has started construction and is planned to go into operation in 2016. As a further component for Masdar's initiative, the Technology Owner and Masdar have completed a front-end engineering and design study

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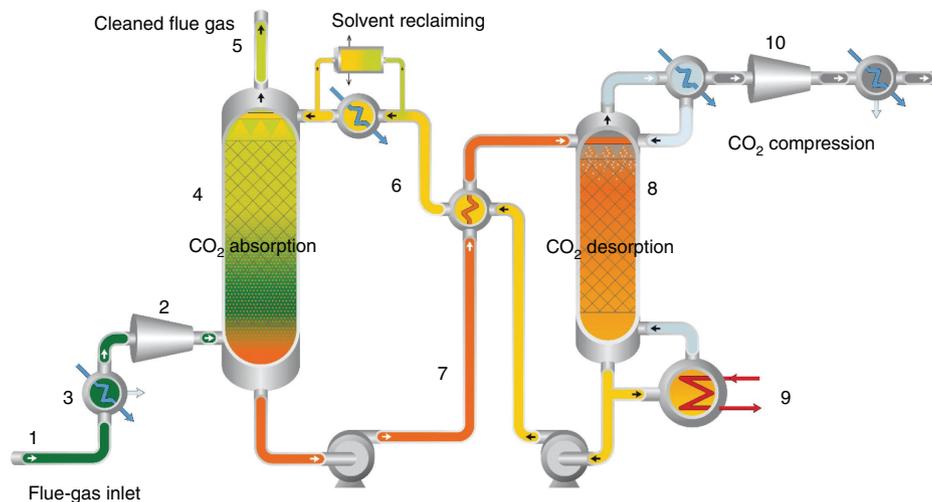


Fig. 1—Simple flow diagram of the PostCap™ process.

for capturing 1,800,000 tons of CO₂ annually per retrofit from a natural-gas-fired power plant in Abu Dhabi by application of the PostCap™ technology. Challenges faced were (among others) the integration of the capture plant into the existing facilities (with the primary goal of not disturbing the power plant), the size of the capture plant, climatic conditions, and the requirements concerning CO₂ quality. For successful project implementation, optimization of capital expenditures and operational expenditures is advisable.

The PostCap™ Carbon Dioxide (CO₂) Capture Technology

The Technology Owner developed a proprietary post-combustion carbon-capture technology named PostCap™ [for details on this process and technology see Jockenhoewel et al. (2009), Jockenhoewel and Schneider (2011), and Reichl et al. (2014)]. The primary targets in the development were to meet stringent environmental requirements without compromising the economics and the operability. The PostCap™ technology uses selective absorption [based on an amino-acid-salt (AAS) solvent] of the CO₂ from the flue gas and subsequent desorption, thus gaining high-purity CO₂. AASs have numerous benefits as CO₂-absorption solvents. This technology has been validated successfully by more than 9,000 operation hours in a CO₂-capture pilot plant adapted to a coal-fired power plant and gas-fired application, as well as by a rigorous laboratory research program.

The particular differentiators of the PostCap™ process are

- Minimal detectable solvent emissions
- Good solvent stability against various degradation mechanisms, particularly against oxygen, and as a result, low solvent-refill need
- Low energy consumption
- Environmentally friendly solvent
- Ease of handling by power-station operators and personnel

Fig. 1 shows a simplified flow diagram of the PostCap™ process. The flue gas to be cleaned (1) is fed by a flue-gas blower (2) into the absorption column (4), where it is countercurrently treated with a (regenerated or lean) washing agent (6) (solvent). Before absorption, any useful heat in the flue gas should be recovered by means of producing steam for heating the reboiler (9) before it is cooled to absorption temperature in a flue-gas cooler (3). During absorption, CO₂ is captured in the solvent so that cleaned gas leaves the column at the top (5). The (rich) solvent, saturated with CO₂, is taken from the absorber's bottom and heated (7) before being fed into the desorption column (8). There, the solvent is regenerated by heat introduction in the reboiler (9), resulting in the release of water vapor and CO₂. The steam is condensed in a condenser at the top of the desorber column so that the remaining CO₂

can be further treated [usually compressed in a multistage compressor with intercoolers and/or liquefied (10)] in a next step. The regenerated washing agent (lean solvent) leaves the bottom of the desorption column and is used for heating the saturated solvent. After further cooling, the lean solvent (6) can again be used for capturing CO₂ in the absorption column.

With the application of a lean-solvent flash, the evaporation of the aqueous phase of the solvent at the bottom of the desorber is supported by lowering the pressure in a flash drum. By doing this, thermal energy can be saved at the expense of the electrical energy used for the generation of the vacuum by the flash-gas compressor. For the capture facility presented in this paper, a thermal-energy demand at the reboiler of 2.7 GJ/t of CO₂ could be accomplished; there is potential for lower values (e.g., with more-favorable process-cooling conditions or higher CO₂ content in the gas stream).

During operation of the carbon-capture plant, a part of the solvent is deactivated continuously by, for example, reaction with minor components in the flue gas. To remove degradation products of the solvent formed by thermal stress or reactions with sulfur oxides (SO_x), nitrogen oxides (NO_x), and oxygen, the solvent is reclaimed in a corresponding reclaimer unit. Without installation of a reclaimer, degraded solvent would have to be fully replaced by delivered fresh AAS substance, increasing operating costs and local transport-related issues (noise, air quality, congestion). Accordingly, a solvent reclaimer enables an economic and sustainable operation of the capture plant over the entire operation time. Thus, we have developed a proprietary two-step reclaiming process for the selective separation of SO_x-related byproducts (usually the major impurity in a flue gas) and for other impurities, including NO_x-related byproducts, from the AAS solvent. To separate the impurities, a split stream is taken from the solvent loop. This fraction of the solvent is supplied to the reclaimer unit, where the solvent is cleaned and resupplied into the process.

Integration of the Capture Plant at the Abu Dhabi Gas-Fired Power Plant

The recent carbon-capture and -storage (CCS) technology roadmap published by the International Energy Agency (IEA) stated that "the largest challenge for CCS deployment is the integration of component technologies into large-scale demonstration projects" (IEA 2013a). Because integration is unavoidable for reducing the energy demand, special focus has to be put on it.

The combined-cycle Abu Dhabi gas-fired power plant, which was identified as one carbon dioxide (CO₂) source for Masdar's carbon initiative, has to provide continuous power for an adjacent industrial application. The plant consists of four 2×1 combined-cycle gas

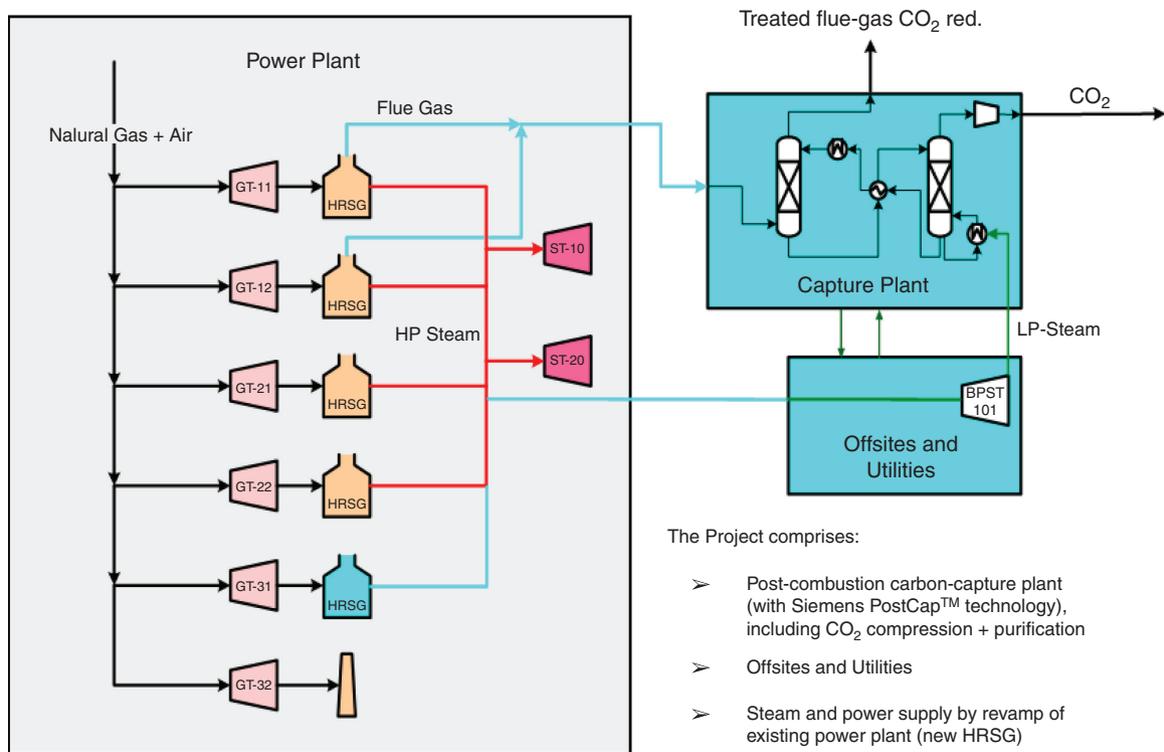


Fig. 2—Schematic of the power-plant and capture-plant arrangement, including offsites and utilities. GT = gas turbine, HRSG = heat-recovery steam generator, HP = high pressure, LP = low pressure, and BPST = backpressure steam turbine.

turbines (Fig. 2), which usually run as base load (with approximately 1,400 MW_{electric gross}), and two open-cycle gas turbines that are redundant and can take over in case of planned or unplanned outages. A possible power shortage can be prevented by temporary duct firing in the remaining combined-cycle machines.

At a very early project stage, it was decided to treat the flue gas from two gas turbines (approximately 4,500 t/h) in the capture plant, thus being equivalent to approximately 700 MW_{electric gross}. With a capture rate of 90%, 240 t/h of the CO₂ are separated.

The so-called “offsites and utilities” (denominated in Fig. 2) are facilities for the handling of utility and chemicals supply and effluents (i.e., backpressure steam turbine, cooling tower, demineralized- and process-water supply, unloading/loading station, and waste incineration).

One of the most-important design preconditions was that the power plant must not be affected in any negative way by the capture plant. This means

1. Steam and power provided by the power plant must always be additional to the quantity and quality of power supplied to the industrial application.
2. Operation of the capture plant must not disturb the power plant. The capture plant must always “follow” the power plant (however, there are requirements toward annual CO₂ production, which have to be fulfilled).

For achieving Precondition 1, an additional heat-recovery steam generator (HRSG) was added for converting one simple-cycle gas turbine to a combined-cycle gas turbine. In case of shortage of one combined-cycle turbine, a combination of three combined-cycle turbines and one simple-cycle turbine could not safely supply the industrial application, in addition to the capture plant, with power and steam. To fulfill Precondition 2, the flue-gas extraction has to be monitored very carefully.

The space assigned to the new plant facilities was limited and consisted mainly of two rectangular plots (divided by seawater pipes underground) north of the existing wet-cell cooling towers (Fig. 3). One main challenge was to convey the flue gas in ducts

to the capture facilities without affecting the cooling towers. This was solved by a pipe bridge partly parallel to the cooling towers and approximately 15 m above ground (see also Fig. 4). Within the new plant facilities, cost optimization had to be accomplished by intelligent material flows (i.e., short solvent piping). For safety reasons, the CO₂ compressor and the emergency stack should be as far away from the power plant (especially the control room) as possible; thus, they were placed at the northwest corner, providing a favorable terminal point for CO₂ to the pipeline. Steam from the additional HRSG (on the left side of Fig. 3) had to be fed into the existing high-pressure (HP) header by means of a new pipe bridge.

For reduced complexity, the 3D model of the new and existing facilities in Fig. 4 does not show the existing gas turbines and HRSGs in detail (gray colored). The capture plant (gray colored) consists of two gas-processing lines (flue-gas cooler/blower/absorber), each assigned to one HRSG. All other process units, especially desorption and CO₂ compression, are arranged in one line.

Flue-Gas Extraction. At the flue-gas interface, extraction from the original stack was provided by amendment of the original stack (Fig. 5). The flue-gas tie-in is most critical with respect to undesired influence on the power plant. Backpressure into the HRSG or the gas turbine has to be carefully avoided. The control concept aims at monitoring the pressure at the bottom of the stack within a very narrow range, and setting the volume flow through the blowers accordingly. In addition to the existing damper in the stack, an additional damper is positioned in the duct toward the capture plant.

To avoid any backpressure effects to the gas turbines, the stack dampers have to be closed slowly and opened quickly (i.e., the after-run time of the blowers has to be significantly longer than the opening time of the stack dampers). After evaluation by dynamic simulation, a revamp of the actuating drives of the existing stack dampers turned out to be necessary. Furthermore, treated flue gas will not be returned to the stack, but will be released on top of the absorbers, which also does not require any additional costly ducting. For protection against heavy rain and the impact of sand

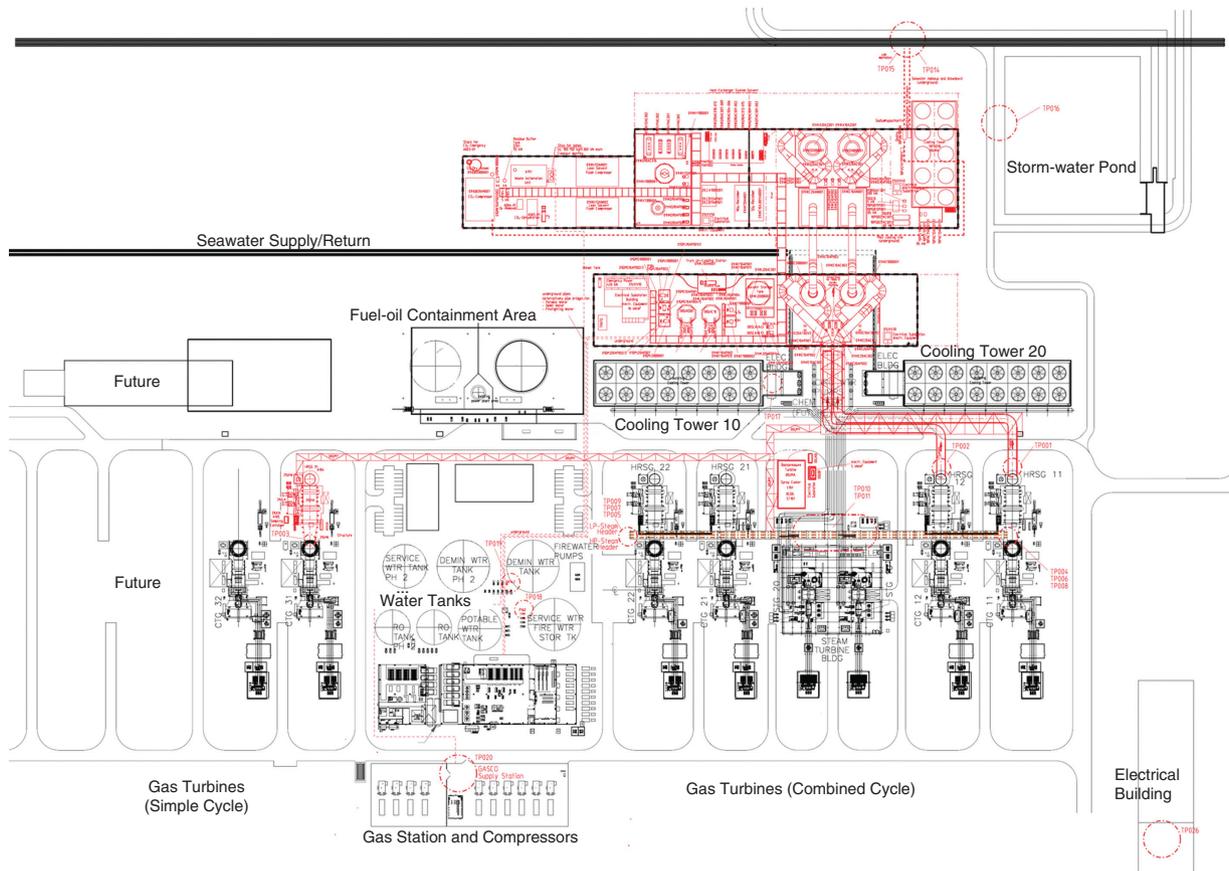


Fig. 3—Layout of new facilities (in red) integrated into the existing power plant.

storms, the absorber columns are equipped with specially constructed dephlegmators.

Steam and Power Supply. The post-combustion capture process requires a supply of heat for desorption of CO₂, and thus, regeneration of the solvent. This typically takes place with steam, indirectly

heating the solvent in a reboiler. Steam is necessary in relatively large quantities and at a comparably low pressure. Usual figures are 3.5 bar/140°C for a desorber pressure of 1 bar and 7 bar/165°C for a desorber pressure of 3 bar, which was chosen for this project. For the resulting thermal-energy consumption of 2.7 GJ/t CO₂, between 1.25 and 1.3 tons of steam are necessary per ton of CO₂. Electric power is

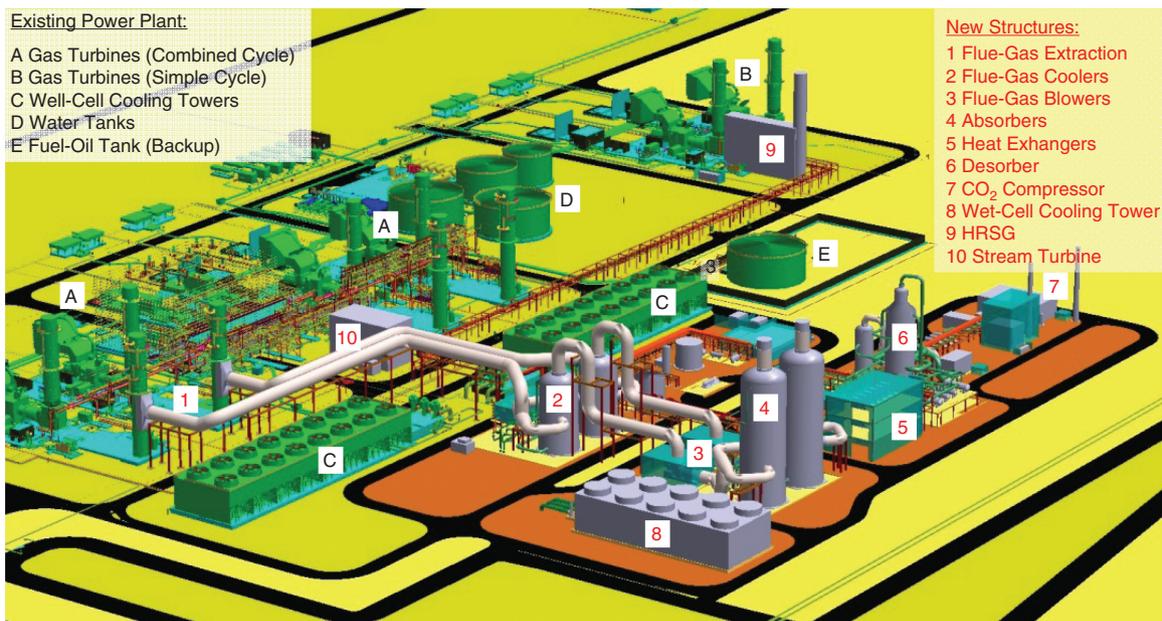


Fig. 4—3D model of new facilities (in gray) integrated into the existing power plant (in green).

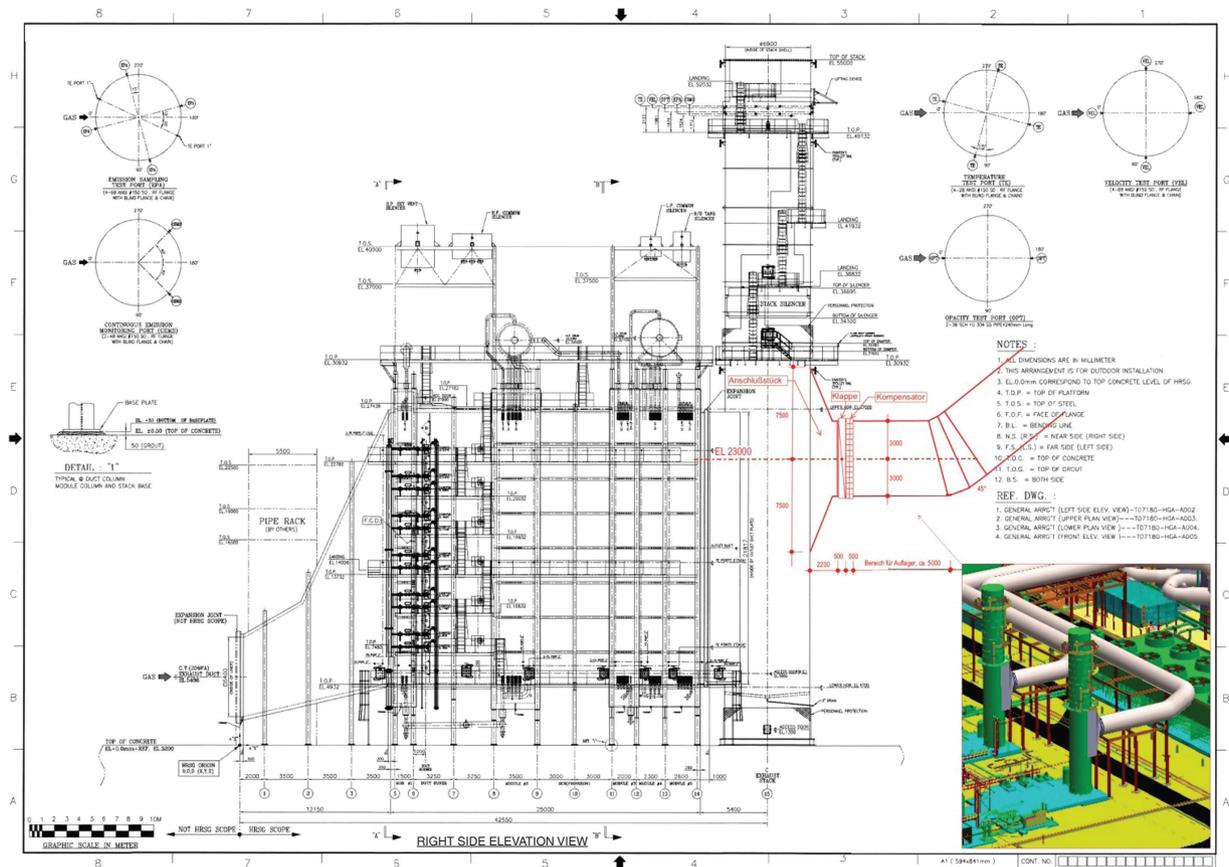


Fig. 5—Flue-gas extraction by stack tie-in.

required for a number of consumers within the capture plant. Large drives, especially for the CO₂ compressor and the lean-solvent flash compressor, can basically be driven either by steam or by power.

To accomplish an optimized solution, five out of many different steam- and power-supply options were evaluated in detail. The design options were

- Option 1: Standard HRSG, HP steam delivered to capture plant, steam drives for compressors
- Option 2: Standard HRSG, HP steam delivered to capture plant, backpressure steam turbine to produce power and low-pressure (LP) steam, one steam drive and one power drive for compressors
- Option 3: Standard HRSG, LP steam delivered to capture plant by throttle, power drives for compressors
- Option 4: Standard HRSG, HP steam delivered to capture plant, backpressure steam turbine to produce power and LP steam, power drives for compressors
- Option 5: Standalone boiler for steam production, power drives for compressors

For the five shortlisted options, both capital expenditure (Capex) and operational expenditure (Opex) were analyzed, as shown in **Fig. 6**. Whereas the four options using a standard HRSG are nearly comparable with respect to Capex and Opex, the concept with the standalone boiler features the lowest Capex, but by far the highest Opex, and is thus not attractive with respect to total cost. For choosing the final option, not only total cost was taken into account, but also operability (especially when choosing power to drive the compressors) and reliability of the arrangement.

The chosen solution (Option 4 in the preceding list), which also supports any later increases in capacity of the power plant, is illustrated in **Fig. 7**. One simple-cycle gas turbine is amended with a dual-pressure HRSG. Electric power is used for all drives.

HP steam is extracted from an existing header and expanded in a backpressure steam turbine; then, it is tempered by use of a spray cooler to achieve reboiler requirements. Condensate is fed back to the existing header of the power plant, after quality monitoring. The power generated in the additional backpressure turbine is roughly equal to two-thirds of the capture plant's demand, but it is supplied by means of the local network rather than directly, to optimize flexibility and reliability of the system. Several medium-voltage (MV) consumers and low-voltage (LV) consumers have to be considered in the electrical-supply concept. Depending on the existing infrastructure and local requirements, the detailed voltage levels have to be investigated with regard to full load operation, startup of large consumers, and short-circuit capabilities.

Process Cooling. The cooling infrastructure for this retrofit capture plant had to be designed completely from scratch. Because of water shortage and environmental restrictions of seawater in the Arabian Gulf (e.g., only 1 K temperature difference between return and supply), air cooling was evaluated as an alternative. However, the high ambient-air temperature in the region determined a design temperature of 46°C for air coolers. Consequently, when limiting the heat-exchanger area and thus the Capex to a tolerable level, achievable temperatures on the process side could not be below 55°C. The capture process, however, requires solvent temperatures of preferably 30 to 40°C. As a compromise, temperatures of 40 to 45°C are also tolerable. The temperature of 42°C in the pump-around of the flue-gas cooler was determined by meeting the water balance within the process, whereas customer specification for the CO₂ temperature at battery limits was 55°C. Consequently, air cooling was not suited to fulfill the complete cooling requirements. Therefore, a wet-cell cooling tower had to be designed, which (on the basis of a wet bulb temperature of 32°C) could provide cooling water at 37°C. A

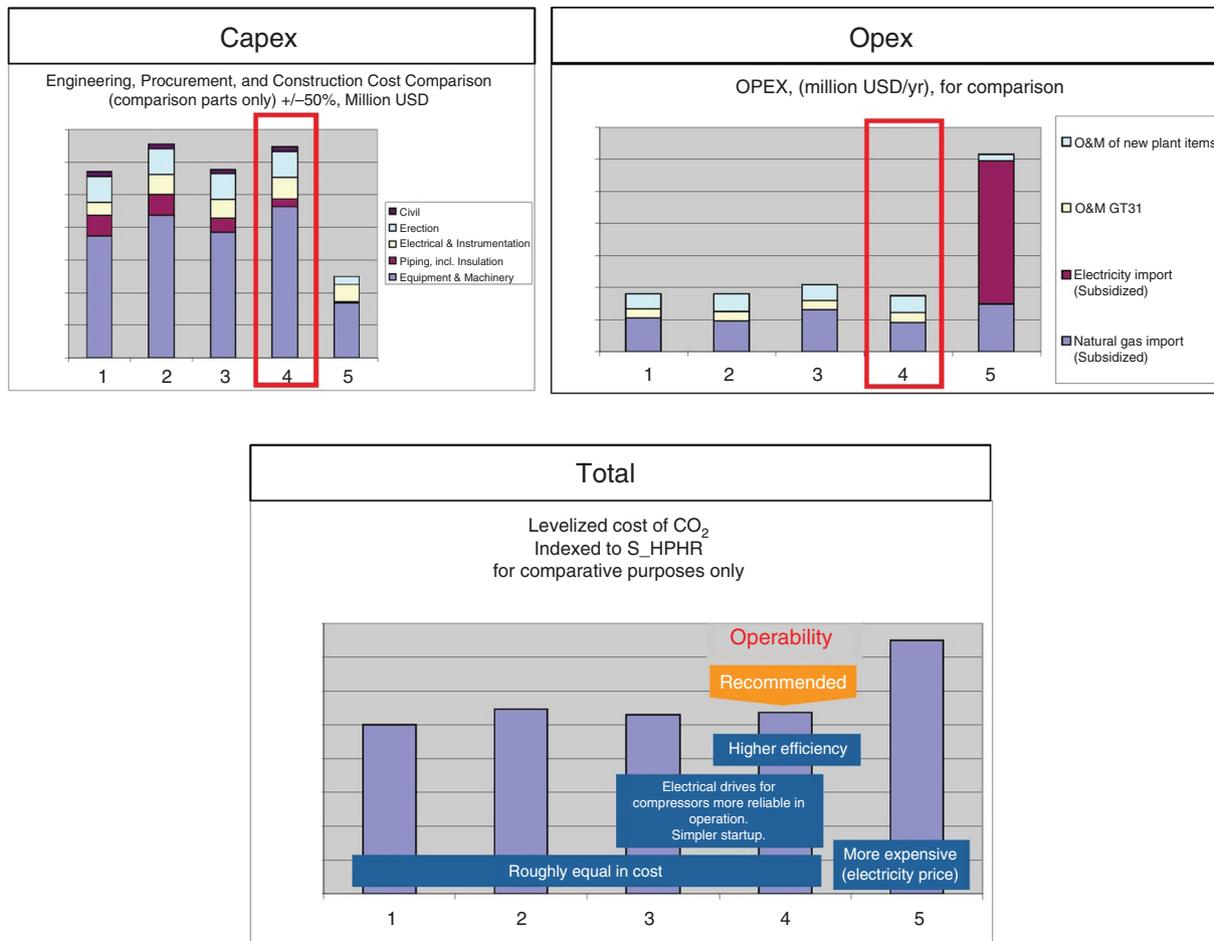


Fig. 6—Criteria for choosing the selected steam- and power-supply option. O&M = operation and maintenance; S_HP HR: S = Siemens concept, HP = high-pressure steam supply, HR = additional HRSG for steam creation.

seawater return stream from a neighboring industrial process could be used as makeup with tolerable prior treatment (neutralization).

Because of the general request for reducing the heat impact on the seawater, it was evaluated whether hybrid cooling would be feasible, meaning a combination of direct air and water cooling. The evaluation comprised the following large-scale coolers within the capture plant, which were basically suited for partly air cooling because of the temperature levels involved:

- Lean-solvent cooler
- Condenser of the desorber
- CO₂ compressor cooler (including intercoolers)

One result of the evaluation was that approximately 30% of the cooling capacity could be transferred to air cooling. However, several reasons against the hybrid solution were found:

- Increased complexity because of additional equipment, piping, and devices for instrumentation and control
- Considerable additional space demand for the air coolers
- Higher Capex and Opex, the latter resulting from electrical power for the blowers

Therefore, the hybrid solution was not selected, and the wet-cell cooling tower was designed to bear the complete cooling task. Two cycles were installed:

1. Primary supply of cooling water in seawater quality to coolers within the capture plant, requiring selection of suitable materials
2. Secondary cycle with demineralized water for cooling tasks within the offsites and utilities, where this was possible because of the given temperature levels

Reclaiming. Because large quantities of flue gas are treated over a long period of time in post-combustion processes, even very small amounts of trace components contained in the flue gas as secondary components [e.g., sulfur oxides (SO_x) or nitrogen oxides (NO_x)] would lead to a noticeable accumulation of secondary products in the solvent pump-around. Therefore, these components must be eliminated by treating a slipstream of the solvent continuously. Reclaimer concepts for amine-based solvents are not suitable for amino acid salts (AASs) because they rely on evaporating the active component. Thus, we have developed a proprietary process for reclaiming AAS solvents (Melcher et al. 2014) that is based on a two-step crystallization process (**Fig. 8**).

A purge stream of the cold solvent is directed to the reclaimer unit, where secondary products formed with the solvent by SO_x and nitrogen dioxide (NO₂) (note that NO will not be absorbed) contained in the flue gas are removed. In the first step, called “SO_x removal,” the blocking of the solvent caused by SO_x is reversed, the solvent is completely regained, and the sulfur components are converted into a marketable fertilizer product. Therefore, the requirements for limiting the SO_x levels upstream of the absorber are less strict compared with other amine-based capture technologies. NO_x-based secondary components are separated in the second step, called “NO_x removal,” with high selectivity as residues that have to be incinerated or disposed of, and the respective loss has to be compensated with fresh solvent. Both process steps can be operated independently. Design of the full-scale reclaimer can be either as a conventional chemical plant (as was done for the case presented in this paper), or as a skid-mounted configuration, allowing easy preassembly, transport, and

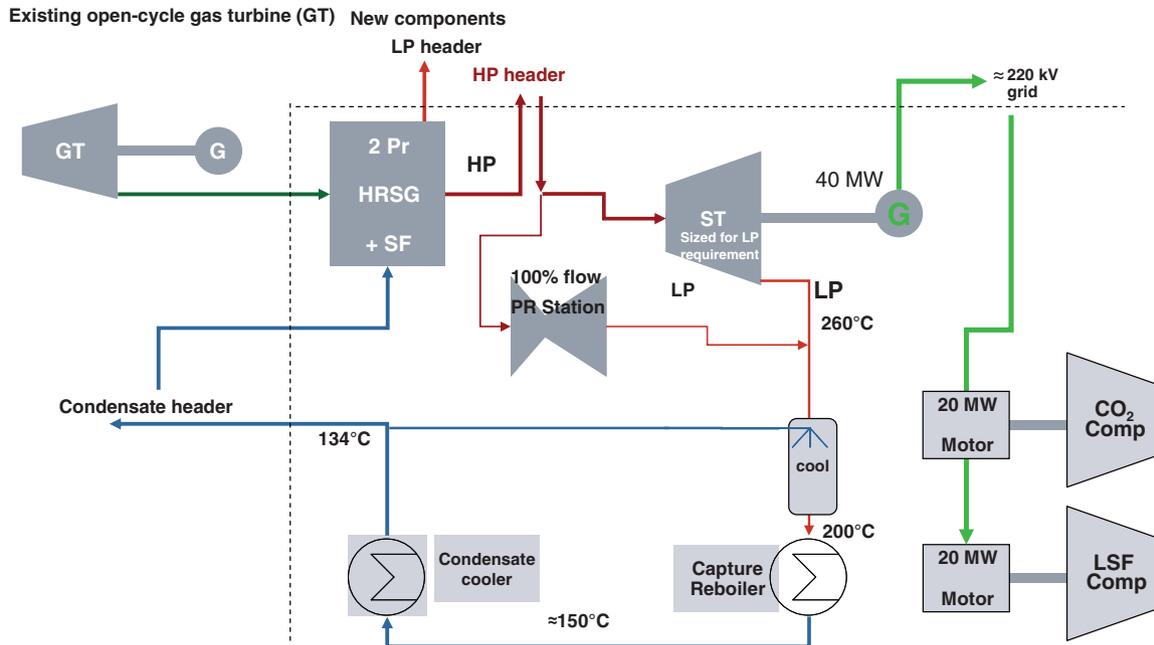


Fig. 7—Selected option for steam and power supply to the capture plant. LSF = lean solvent flash (compressor).

installation (Fig. 8). If one skid is not sufficient for treatment of the solvent, simple numbering-up will be executed.

CO₂ Purification. With respect to CO₂ purity, water (H₂O) and oxygen (O₂) are the two components with the highest importance. H₂O content must be low mainly to prevent pipeline corrosion, whereas O₂ has to be limited especially for enhanced-oil-recovery (EOR) applications to avoid oxidation of the crude oil in the underground reservoirs. Currently, there are no universally agreed figures for maximum values. For pipeline transport without EOR, literature data (Havens 2008; Forbes et al. 2008; Jordanger and Røkke 2009; NETL 2012, 2013; Dugstad et al. 2014) and the project experience of the authors come to ranges of 10 to 700 ppm(v) for H₂O and 15 to 40,000 ppm(v) for O₂. If there are subsequent EOR uses, the ranges are 10 to 500 ppm(v) for H₂O and 5 to 70 ppm(v) for O₂ (Forbes et al. 2008; NETL 2013; Dugstad et al. 2014, and specifications for PostCap™ projects). Food and beverage applications usually require 20 to 30 ppm(v) for H₂O and 30 to 50 ppm(v) for O₂

(CGA G-6.2 2011). As a conclusion, methods have to be available to reach <10 ppm(v) for H₂O and <5 ppm(v) for O₂.

Most (but not as much as necessary) of the H₂O contained in the CO₂ downstream of the desorber top condenser is removed in the CO₂ compressor by condensation in the intercoolers. Therefore, and to reduce equipment dimensions, it would be advantageous to place the CO₂-purification equipment downstream of the CO₂ compressor. However, HP vessels and columns are too expensive. Thus, as a result of economic optimization, CO₂ purification will be operated at a pressure range between 20 and 40 bar and located between two adequate steps of the multistage CO₂ compressor.

Besides other methods, such as cold distillation or chemisorption on copper, deoxygenating can be accomplished by catalytic oxidation. The process is based on the exothermic reaction of hydrogen with oxygen:

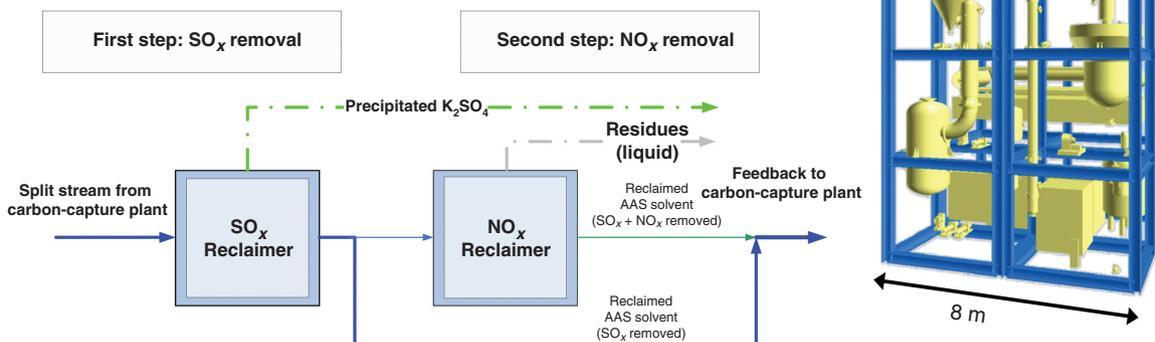


Fig. 8—Reclaimer concept and example for skid-mounted full-scale reclaimer.

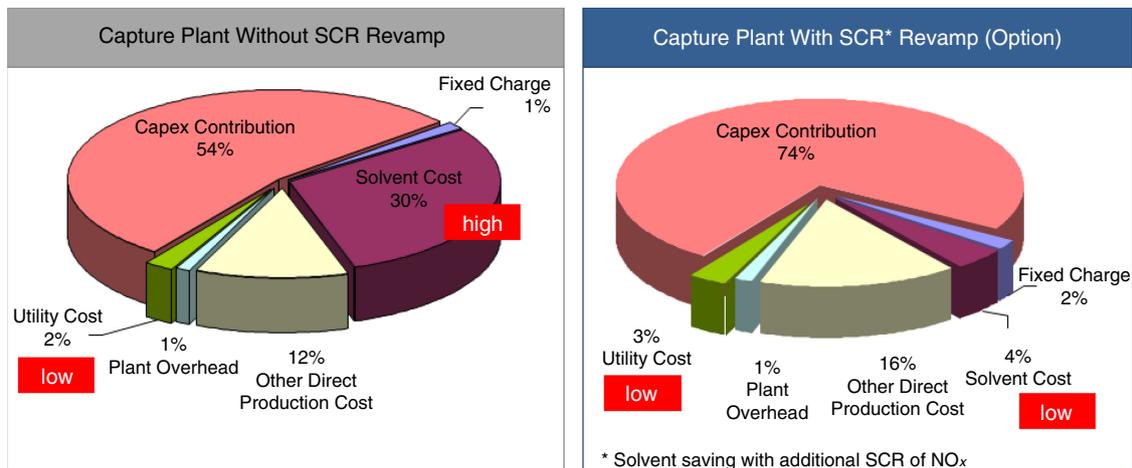


Fig. 9—Impact of NO_x reduction in flue gas on the cost of CO₂ produced.

The activity of a noble-metal catalyst is sufficient for technical applications at temperatures of approximately 80°C. Depending on the design, the oxygen content in the treated gas can be brought down to less than 5 ppm(v); in this case, the residual hydrogen content in the gas then lies between approximately 25 and 50 ppm(w). The process and the respective equipment are easily scalable. Because of these features, catalytic oxidation was the chosen deoxygenating method for the project, and because water is the reaction product, this process step has to be located upstream of the dehydration.

For dehydration, adsorption was the chosen method. The process is well-established, suited for purification down to <10 ppm(v) of H₂O, and easily scalable for drying gases. Substances that are particularly well-suited as adsorption agents are the amorphous forms of inorganic silica gel or (if lower moisture contents are necessary) the crystalline structures of artificial zeolites, which have become known as molecular sieves. For a continuous operation, at least two fixed-bed adsorbers are required. These units are alternatively loaded or regenerated (for which a small CO₂ slipstream can be used, which is then refed upstream of the CO₂ compressor), whereby regeneration always takes less time than loading. Absorption by ethylene glycol (EG) or triethylene glycol (TEG), which is sometimes discussed as an alternative method, was ruled out because introduction of EG or TEG traces into the CO₂ cannot be avoided. Another promising method is refrigeration/condensation with the help of the Joule-Thomson effect (Kumar et al. 2010); however, there are currently only a limited number of references.

As for H₂O and O₂ in CO₂, limiting values are usually also given for SO_x, NO_x, capture solvent, and in some cases for nitrogen. Because practically no desorption of SO_x and NO_x from the AAS occurs, the respective limits can be met. As a result of the nonvolatility of AAS, solvent traces in CO₂ are hardly detectable. To avoid emission of solvent droplets into the downstream CO₂, a demister at the desorber outlet is included in the design. To some extent, nitrogen will end up in the CO₂; however, because of its characteristic of being an inert gas, consequences of effects on CO₂ product properties, and thus threshold values, are still under discussion.

Capex and Opex Optimization. As the fundamental parameter for an investment decision, the levelized cost of CO₂ produced has to be evaluated. It is determined by both Capex (investment) and Opex (operating cost). Fig. 9 shows the contribution of various cost factors to the overall cost for two configurations of the power plant, which have considerable impact on the capture plant.

- No special NO_x-reduction equipment on the power-plant side, thus delivering flue gas containing approximately 27 ppm(v) NO_x.

- Revamping a unit for selective catalytic reduction (SCR) in the HRSG, thus reducing the NO_x content by approximately 90%. The addition of the SCR unit is a relatively low-investment procedure because a spool for retrofit is already available.

For the plant version without SCR revamp, Capex accounts for 54% of the cost of CO₂ produced (related to a depreciation time of 20 years), thus 46% is the result of Opex. Out of the latter, by far the largest part (overall 30%) is the cost for solvent refill. This is because NO_x (or more precisely NO₂) tends to react irreversibly with amine-based solvents. Consequently, by reducing NO_x in the flue gas with SCR, the cost segment determined by solvent refill is reduced considerably to only 4%, as shown in the illustration for the plant version with SCR revamp. Capex then makes up 74% of the total cost. It should be kept in mind that these relative cost portions especially apply for plants located in the Middle East, where operators can benefit from substantially inexpensive energy through low gas prices. For sites in other parts of the world, Opex usually has greater weight.

SCR revamp is the most-obvious lever for cost reduction and will in this case bring down the overall cost of CO₂ produced by approximately 25%. The levelized production cost for the CO₂-capture plant, taking into consideration Capex (with a depreciation time of 20 years, a real interest rate of 10%, and an annual inflation rate of 3%) and Opex, then accounts for USD 65/ton of CO₂ (status of 2012), whereas the thermal-energy demand at the reboiler comes to 2.7 GJ/ton of CO₂.

As for further Capex reduction (not yet considered in Fig. 9), process redesign with omitting the flue-gas cooler seems to be the most promising approach. Because the flue gas from gas-fired power plants is relatively clean, the flue-gas cooler has practically no washing function, and the cooling task can be transferred into the absorber by adding a side cooler for the solvent. The resulting Capex advantage by omitting the flue-gas cooler can reduce the overall cost of CO₂ produced by another approximately 5 to 10%. Another cost-reduction lever is seen from a summation of further smaller optimizations and by competitive engineering. With these measures, the cost of producing CO₂ by capturing from flue gas can be brought into a range that will make application for EOR attractive.

Conclusion

Because of the further growing world demand for crude oil and (sooner or later) limited resources, a high business potential is seen for enhanced oil recovery (EOR) with carbon dioxide (CO₂). When capturing the required CO₂ from power-plant flue gas, simultaneously a contribution is made to fight against global warming.

The PostCap™ technology developed for capturing CO₂ from flue gases originating from coal- and gas-fired power plants and from industrial sources is ready for large-scale application. PostCap™ can be retrofitted to any power plant—independent of the manufacturer or type. The challenges of integrating a carbon-capture plant as complex as a new chemical plant into an already-complex and often singular power plant can be handled competently by the teams of chemical-plant and power-plant engineers working side by side. The expertise already available in integration of power plants with other neighboring technology provides the technical capacity and toolkit to optimize shared processes such as the water/steam cycle and cooling supply.

On the basis of the current level, the cost of CO₂ produced by carbon capture can be further reduced by process and plant redesign and optimization, thus becoming more and more attractive for EOR applications.

Considering the lessons learned in the preceding work, a very promising approach is seen in upgrading simple-cycle power plants to combined-cycle power plants. A large fleet of simple cycle power plants is in operation, especially in the Middle East.

By adding a heat-recovery steam generator (HRSG) and a backpressure steam turbine, the steam and power necessary for operating a carbon-capture plant can be produced, even leaving a surplus. Thus, the upgraded plant will deliver CO₂ and additionally more power than before. For HRSGs and backpressure steam turbines, a broad variety of designs are available, ranging from “low cost” to “technically optimized.” This gives the opportunity to develop a customized and profitable solution on a case-by-case basis.

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