WORLD ENERGY COUNCIL
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Energy Efficiency Technologies

ANNEX III

Technical Report

Energy Efficient Solutions for Thermal Power Plants

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WEC Knowledge Network

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High Efficient Solutions for Thermal Power Plants

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1. Introduction

Understanding and comparing generating efficiency across power generation assets is a very challenging problem due to differences in technology, operation, fuel, size, and age. Even what in concept would seem very straightforward, such as monitoring fleet generating efficiency to produce realistic improvement targets, is a more difficult task than one might think at first glance. The reasons are many and include factors such as the simple fact that it is not easily measured, asset diversity (as noted above), and normal asset degradation. From the perspective of producing improvement targets, even a comparison of a unit to its own historical or design performance is a challenge due to changes in operation, modifications made to address environmental regulations, normal degradation, changes in fuel quality/sourcing or equipment upgrades. Comparison of a particular unit to its “peers” is further challenged by the large diversity of plant design configurations and the non-standard protocols for plant data, instrumentation and performance calculations. Unit-level performance calculations tend to be highly customized, resource-intensive and not well suited for producing centralized performance metrics.

One important factor to consider when comparing generating assets is to ensure that all metrics of efficiency are compared on an equal footing. The United States and a minority of other countries typically refer to boiler and plant efficiency on a *higher heating value (HHV) or gross calorific value (GCV)* basis, which for a combustion unit signifies that the latent heat of vaporization of moisture from the fuel is recovered. Whereas most of the world refers to boiler and plant efficiency on a *lower heating value (LHV) or net calorific value (NCV)* basis. Neither metric is “right” or “wrong,” but it is important to understand the differences when assessing generating asset efficiency.

The primary metric of unit efficiency used in the industry is the *heat rate* of the unit, which is a ratio of the energy required to produce a unit of electricity – such as how many Btu/hr of fossil fuel are required to produce 1 kW of electricity at the generator terminal. Design heat rates vary significantly based on plant type. Actual heat rates may vary by as much as 10-15% from factors including normal degradation, fuel source, how well it’s operated, etc. As an example, the heat rate of a large coal plant may be reduced by 3-4% by switching from a bituminous fuel to a low sulfur sub-bituminous coal. This efficiency loss, when coupled with the expected increases in unit auxiliary power which are coincident with using a lower-quality coal, can result in a reduction in the plant efficiency of 5% or more! A combustion turbine based plant burning natural gas may perform 1-3% better than the same plant design burning oil. Another factor affecting many coal plants is the addition of emissions equipment such as Selective Catalytic Reduction (SCR) systems and flue gas scrubbers which may hurt performance by as much as 1-2% in exchange for reducing SO_2 emissions. One of the large hurdles to CO_2 sequestration is the huge impact on unit performance of as much as 50%.

In the following chapters the different technology options based on thermal power generation will be described assuming the efficiency definition based on LHV. Components and processes influencing the overall plant performance will be discussed by its technological potential. Furthers factors like degradation and different operation modes are not considered.

2. Gas Fired Combined Cycle Power Plants

Combined cycle power plants (CCPPs) have been serving the growing demand for power since the 1970s. Over the past 40 years, needs have shifted from fast and low-cost power supplies towards sustainable and flexible power generation. Growth of this type of plant began in the 1980s when gas became widely available as an indigenous fuel in Europe and Asia, and the plants had low capital costs, could be quickly built and had low maintenance costs. They were increasingly used to serve the growing IPP (Independent Power Producer) market, but also to meet expanding utility requirements. Later in the 1990s, this plant concept gained further merit as the lowest emission generator other than nuclear power. Beginning around 2000, flexibility began to gain greater importance as a way to compensate for the growing share of fluctuating renewable generation in the system. Over the years, combined cycle plants have been optimized with further innovations in gas turbine, steam turbine and generator technologies, as well in the steam/water cycle in order to meet the growing trend toward sustainable technologies, reduce the consumption of resources and minimize fossil emissions. Combined cycle plants are used today, even if coal is abundantly available, as a means of diversifying primary energy and valuable back up capacity.

Gas-fired power plants with state-of-the-art gas turbines are highly sophisticated plant and technology concepts offering unmatched excellence in operation, reliability and environmental friendliness. The power industry can make substantial contributions – most notably massive resource savings and lower CO_2 emissions – to the long term sustainability of fossil power generation only with such high innovation power. Comparing the efficiency and CO_2 emission levels of all type of fossil power plants these gas turbine-based combined cycle power plants are the most sustainable, predictable and reliable power generation technology available at present. CO_2 emissions from modern gas-fired combined cycle power plants are around 57% lower than those from state-of-the-art hard coal-fired plants.

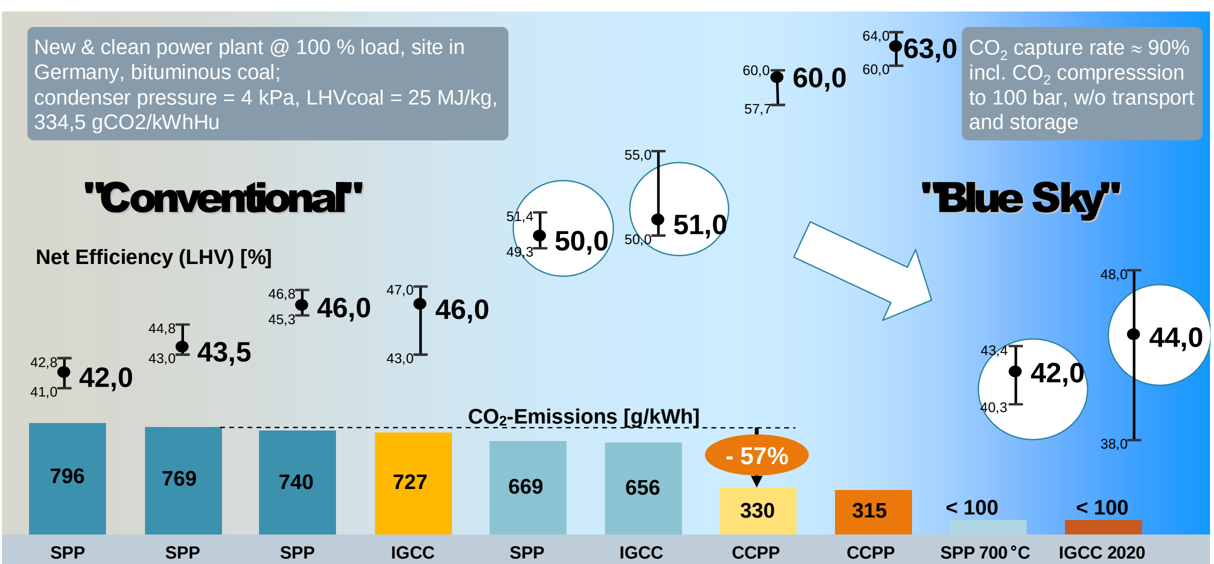


Fig. 1: Net Efficiency of current and future plant concepts

Advanced combined cycle technology is based on the latest developments in gas turbine technology that allow highest mass flow, lower losses in compressors, turbine inlet temperature above 1,500°C and optimized pressure ratios to meet also the requirements of a high-temperature steam end. These advances are supported by the use of improved and even new materials in all rotating equipment, ceramics in the combustion and turbine sections, and state-of-the-art design and calculation tools and innovations in other areas.
Fully water-cooled generators and high-temperature steam turbines also contribute to the lowest CO_2, NO_x and SO_2 emissions as well to the highest efficiency for all fossil power plants. In the associated steam/water cycle, also here the use of new materials as well as innovative steam generators helped increase efficiency over the past 15 years from around 50% to today's proven record of 60.75% (LHV), which was measured in Germany's Ulrich Hartmann (Irsching 4) plant in mid-2011. The plant has since accumulated over 15,000 hours of commercial operation.
The CCPP plants in Andong and Daegu City, South Korea, are excellent examples of the success of this advanced technology in markets like Asia, which have high gas prices through supplies of LNG (Liquefied Natural Gas). Beginning in 2015, these two plants – with capacities from 400 to 420 MW and efficiencies in the range of 61% net – will provide electricity to around 200,000 urban households and will save gas and about 3.5 million tons of CO_2 a year compared to existing power plants in the area.

In countries like Germany, this technology is also supporting the current energy transition towards renewable energy sources since the plant concept allows extremely flexible operation for backing up power for fluctuating wind and solar supplies and ensures grid reliability and stability.
The term "combined cycle" describes the combination of two thermodynamic cycles, with the gas turbine (Brayton cycle) burning natural or synthetic gas from coal/residuals/oil, and its hot exhaust gas powering a small steam power plant (Rankine cycle). Combined Cycle Power Plants (CCPPs) can achieve a thermal efficiency higher than 60% today, compared to single cycle gas power plants which are limited to efficiencies of around 35 to 42%.

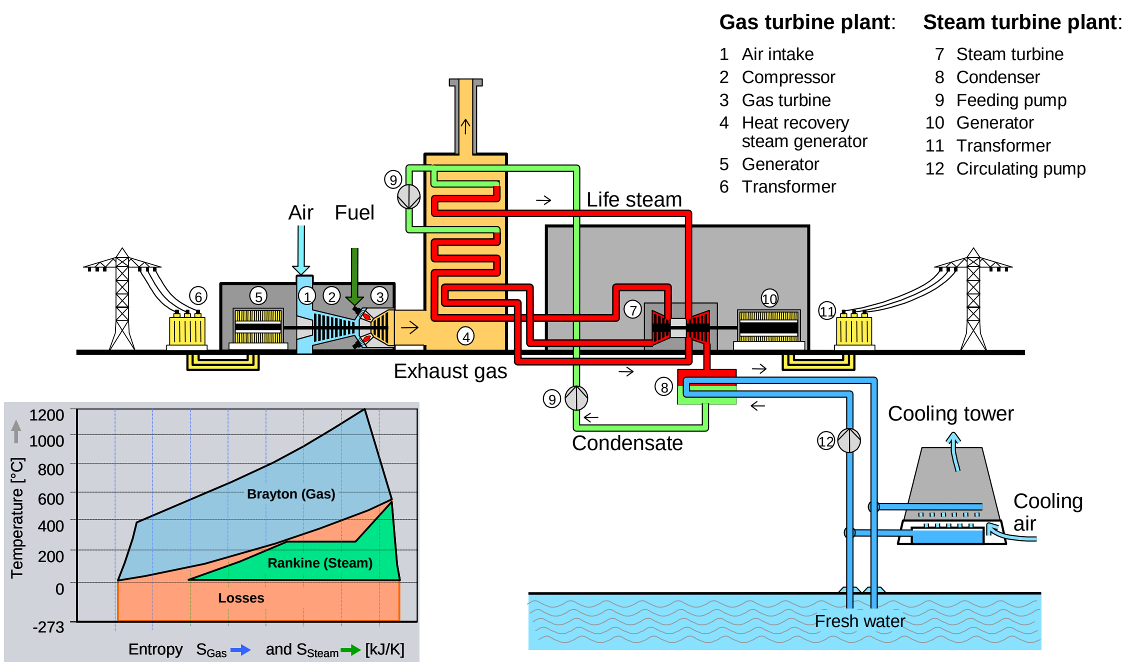


Fig. 2: Combined Cycle Technology

Efficiency, which is defined as the usable electrical energy generated from the plant's divided by fuel energy, is determined by the following factors:

- Efficiency of the gas turbine and other rotating equipment through their aerodynamic design, cooling technology and upper Brayton process temperature (turbine inlet temperature),
- Design efficiency of the Rankine cycle through the temperature and pressure of the steam generated from a single pressure to a triple pressure reheat cycle with the condenser pressure as the lower process temperature,
- Cooling technology used as direct water-, to indirect air- and to direct air cooling.

CCPPs today achieve efficiencies ranging from 52 to 61%, depending on the above factors and on environmental conditions such as air inlet and cooling temperatures.
The increasing efficiency achieved over the years demonstrates the huge innovation potential and development progress supporting this plant technology.

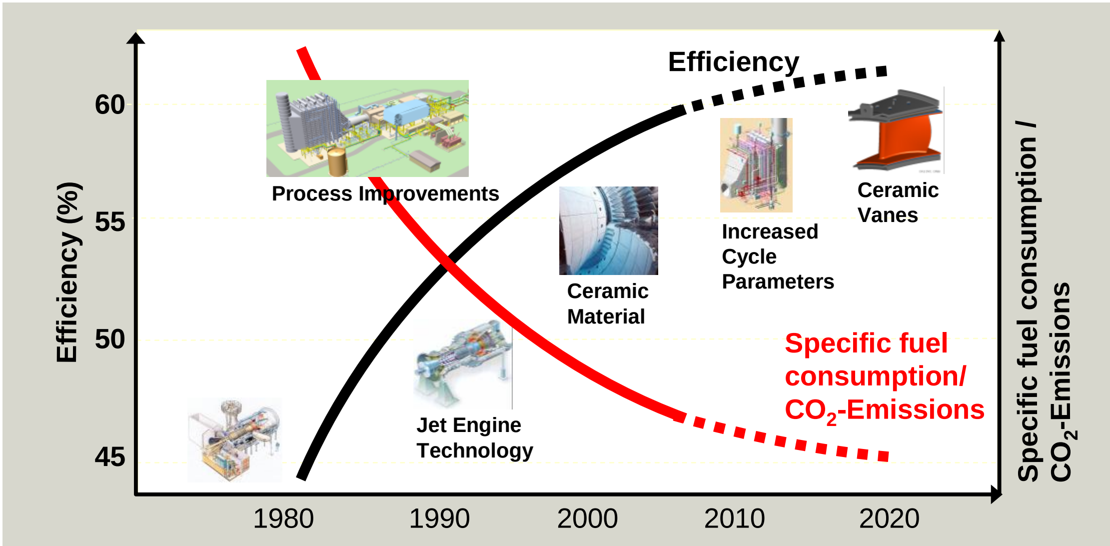


Fig. 3: High increase of CCPP efficiency

The reduction of CO_2 emissions is also directly related to the improvement in efficiency, as shown in the chart above. Innovations at materials and processes are leading to increasing efficiency and related CO_2-emission reduction in CCPPs. Today, the most advanced combined cycle power plants can reach a net efficiency higher than 61% and a fuel utilization rate (including the use of commercial heat) of above 85% with CO_2 emissions of less than 325 g/kWh.

Technologies

These improvements are remarkable and were driven by various innovations and developments in the following areas:

- gas turbines with increased firing temperatures,
- advanced base materials and ceramics, particularly in the hot gas path of the gas turbine,
- advanced cooling technologies such as film cooling in the first rows of blades and vanes,
- reduced losses in the rotating equipment through sophisticated designs and seals,
- advanced materials and process designs for the exhaust heat exchanger HRSG,
- once-through (Benson) HRSG design to reduce losses,
- high-temperature steam turbine technology derived from steam power plants.

Other techniques for improving power plant sustainability and eco-friendliness can be applied case by case depending on customer requirements:

- low NO_x combustion technology to reduce emissions to less than 25 (down to single digit) ppm,
- selective catalytic reduction (SCR) for NO_x: application of a titanium dioxide-based catalytic converter with NH_3 (ammonia or urea) to reduce NO_x emissions by a further 70 to 90%,
- CO oxidation catalyst to oxidize unburned CO into CO_2 and allow a wider operation range,
- Flex plant or FAst CYcling (FACY) concept to reduce fuel consumption and CO_2 emissions during start up through integrated and innovative hardware and software technology,

- WETEX: combined technologies in order to reduce water consumption to zero,
- CCS (Carbon Capture & Storage) under development for coal- and gas-based plants.

Example: Siemens CCPP solution based on new H-class gas turbine

Many of the developments and innovations mentioned above have been integrated into a new combined cycle technology called the SCC-8000H, whose development began in 2001.
As a result of these innovations, the plant concept could be developed based on a fully internally air cooled gas turbine and an innovative cycle design enabling both unprecedented efficiency and flexibility. The concept design had the following simple targets.

- increase efficiency above 60% net,
- increase operating flexibility to meet future grid demands,
- achieve the most economical and ecological fossil power generation.

The key contributors to efficiency improvements without using steam for cooling were:

- increased pressure ratios and turbine inlet temperatures, optimized towards combined cycle efficiency,
- improved component efficiency of the compressor, turbine, generator and steam turbine,
- increased fuel preheating.

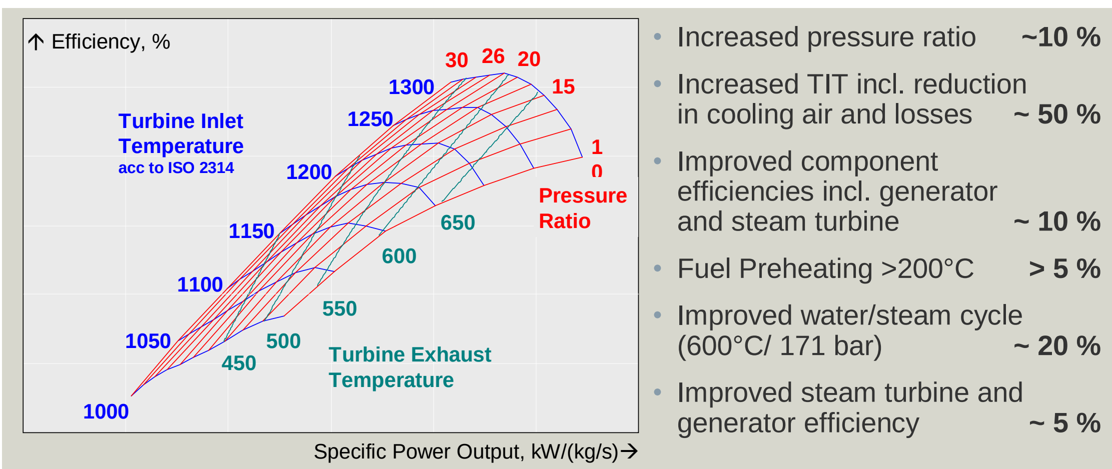


Fig. 4: Increase of Combined Cycle Efficiency by component and plant innovation

In July 2011 – following years of intensive development, testing and field verification between 2007 and 2010 – Siemens began the first commercial operation of the world’s most efficient and flexible power plant based on this concept. The Irsching 4 unit in Bavaria, Germany, generated 575 MW and achieved 60.75% efficiency in its first tests, which were verified by the German consultant TÜV- Süd. The plant is owned and operated since by the German utility E.ON and is supporting Germany’s energy transition with its flexible operation mainly in a two-shift mode.

The key success factors of this plant’s concept are:

- the largest, most efficient and flexible heavy-duty gas turbine using the most advanced technologies, fully internally air cooled with special features such as hydraulic clearance optimization (HCO),

- specific Siemens single-shaft arrangement of the gas turbine, water/hydrogen-cooled generator, steam turbine,
- 600°C steam cycle with Benson HRSG technology and high-temperature steam turbine technology derived from most advanced supercritical steam plants,
- major flexibility features in the steam/water cycle coupled with the latest I&C technology.

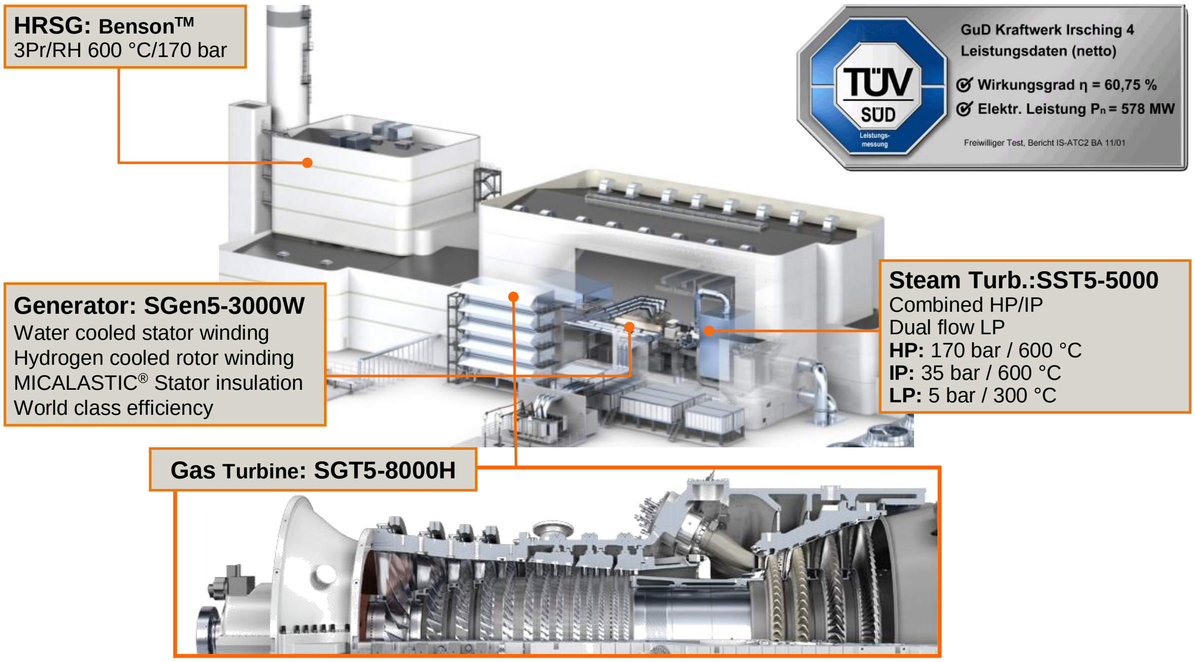


Fig. 5: Innovative design features and proven technologies lead to efficiency above 60%

The Irsching plant has integrated all the developed and tested features and has been in commercial operation since July 2011. By October 2013, the plant will have racked up around 20,000 equivalent operating hours with more than 500 starts.

All required tests have proven that this plant has surpassed all the targeted development features:

- Output >575 MW (50 Hz)
- Efficiency >60.75% (LHV)
- NOx level < 25 ppm
- Start-up time (hot start) < 30 minutes
- Ramp rates >35 MW/minute
- Supports the most stringent European grid code requirements

Inspections through a boroscope and the first hot gas path inspection in May 2012 underscored that the plant and its components are performing very well and as expected.

The major environment benefit from this increased efficiency and flexibility is the reduction of CO_2 emissions. Such plants ensure major emission reductions compared to existing technologies such as coal-fired, open cycle or older-vintage combined cycle plants.

The efficiency improvement is a major commercial driver for these gas turbines and plants. Depending on the fuel price for piped natural gas or LNG, this plant concept can generate a major commercial benefit in the range of 0.7 to >3% points compared to the previous F- class technology.

Examples for highest efficient CCPPs

1. Lausward (50 Hz):

The Lausward plant is being built on the Rhine River in the heart of Düsseldorf in the state of North Rhine Westfalia and will not only meet the region's power requirements with its flexibility, nearly 600-MW capacity and 61% net efficiency, but also extract about 300 MW heat to support the city's district heating system. The plant will achieve a fuel efficiency of about 85%. In other words, the plant will convert 85% of its natural gas input to commercially usable electricity and heat.

Lausward Düsseldorf SCC5-8000H 1S	
Customer	**Stadtwerke Düsseldorf**
Total Power Output	596 MW net
Plant efficiency	>61 % net
ST Type	SST5-5000
Generator Type	SGen5-3000W
Date of order	May 2012
1st comm. operation	mid 2015

Special features
- ✓ District heating 300MWth
- ✓ 85 % fuel efficiency
- ✓ CO_2-Emissions less than 325 g/kWh
- ✓ Hot start in 30 min to full load

Fig. 6: Siemens technology in Lausward (Germany) – 50Hz CHP CCPP

The project is under construction by Siemens and will be commercially operational in mid-2015. The plant will meet further exceptional benchmarks in power generation:

- the highest net efficiency ever, at >61%

- the highest output ever from a single train >595 MW
- the highest heat extraction from a single train at >300 MWth
- the lowest CO2 emissions ever for a fossil power plant, at <325g/kWh

Since it is located in the center of Düsseldorf, it also features a special architectural design and very high noise abatement features.

2. Andong (60 Hz)

The 417-MW Andong Power Plant, owned by KOSPO is located near Andong, a city with 170,000 population about one hour northeast of Daegu. Andong is known for its traditional attractions and lifestyle and as the home of Confucianism.

Andong
Korea
SCC6-8000H 1S

Customer	**KOSPO**
Total Power Output	417 MW gross
Plant efficiency	>60, 9 % gross
ST Type	SST6-5000
Generator Type	SGen6-2000H
Date of order	April 2012
1st comm. operation	March 2014

Special features

- ✓ CO_2-Emissions less than 325 g/kWh
- ✓ Hot start in 30 min to full load
- ✓ Fast track execution < 2 years

Fig. 7: Siemens technology in Andong (South Korea) – 60Hz CHP CCPP

The city consumes about 2,700 MWh of electricity daily and will be fully served by this new plant. The facility has been designed to operate at the highest efficiency of more than 60% net (LHV) and with very high flexibility in order to reduce fuel costs and CO_2 emissions, and to increase the flexibility of the plant portfolio in the area. The plant concept is based on Siemens' proven single-shaft design with the latest SGT6-8000H gas turbine ensuring highest efficiency and flexibility. With CO_2 emissions of less than 330 g/ kWh, the plant will produce less than 40% of the emissions released by a coal-based plant about 100 kilometers north of Andong. The plant is designed for extremely flexible operation, with about 250 starts a year and 3,800 full load hours per year.

3. Daegu Green Power

The 400-MW Daegu Green Power Combined Heat and Power Plant (CHP) is located near the city of Daegu, with a population of 2.5 million and host of the WEC in October 2013. The city consumes about 41,000 MWh daily and the new plant will provide around 20% of the population with cleanest electricity and heat.

Daegu City Korea SCC6-8000H 1S	
Customer	**Deagu Green Power** **(KOSPO/Lotte/BHI/ Daegu City)**
Total Power Output	415 MW gross
Plant efficiency	>61 % gross
ST Type	SST6-5000
Generator Type	SGen6-2000H
Date of order	Sept. 2012
1st comm. operation	June 2014

Special features

- ✓ District heating 190MWth
- ✓ >79 % fuel efficiency
- ✓ CO_2-Emissions less than 325 g/kWh
- ✓ Hot start in 30 min to full load

Fig. 8: Siemens technology in Daegu (South Korea) – 60Hz CHP CCPP

South Korea plans to supply district heating to more than 20% of the country's 18 million households by 2014, and is seeking to end the use of electricity for residential heating. The demand for heating and air conditioning increased this year compared to 2009, and since economic growth is projected to remain on track, CHPs will provide an economically viable solution for meeting the need for electricity and heat from a single source. This power plant is being designed to achieve the highest efficiency of over 60% net (LHV), and will offer very high flexibility in order to reduce fuel costs and CO_2 emissions and to increase the flexibility of the plant portfolio in the area. In addition, extracted heat totaling about 190 MWth will serve around 24,000 households in the city center. This combination will increase fuel utilization to over 79%, especially during the winter season.

The plant concept is based on the same proven single-shaft design as Andong, with the latest SGT6-8000H gas turbine ensuring high efficiency and flexibility with the same operation regime and low level of CO_2 emissions.

In addition, many other new plants of this type are already operating or are under construction by Siemens or using Siemens technology in South Korea. These projects include Dangjin-gun (420-MW Bugok 3, completed in May 2013), Incheon (1,250-MW POSCO 2, to be completed late in 2014), and Gyeonggi-do (840-MW Ansan, to be completed in 2014). In principle, they have similar features and offer the benefits of highest efficiency with the fully air-cooled H-class gas turbine, combined with highly advanced 600°C steam cycle technology and highest flexibility features, such as Benson HRSG.

All of the above-described plants will be fueled by the cleanest fossil fuel, liquefied natural gas. LNG is the country’s power generation backbone after nuclear and coal, and is contributing about 25% of South Korea’s electricity production. LNG is primarily imported from Qatar and Indonesia.

3. Integrated Gasification Combined Cycle (IGCC)

Gasification is the key to converting large energy reserves into a clean gaseous feedstock for both power generation and the production of chemicals and clean fuels. Integration offers the potential for high coal-to-power IGCC efficiencies, but the general trend in integrated gasification combined cycle power plants (IGCCs) is toward less-integrated configurations because they are easier to start, less complex to operate, and can use gas turbines and CCPPs designed for natural gas with only minor modifications. The inherent chemical processing aspects of IGCCs make them ideal polygeneration plants

Coal will remain the main long-term resource, but refinery residues from increased oil production will also be utilized. Gasification provides the fuel flexibility to use all of these fuels, and polygeneration plants with gasifiers can convert a variety of fuels into multiple products. IGCC and polygeneration facilities are currently viable, but further development is needed for the core components as well as for overall plant concepts and designs. A future configuration of coal-to-chemical plants could integrate chemical storage of renewable power by electrolyzing water into hydrogen and oxygen, then using the oxygen for gasification and using the hydrogen to obtain the correct H:C ratio for the chemical synthesis.

3.1 Gasification is the Core Process

The key to opening coal and low-grade fuels for use in gas turbines is gasification, which converts large energy reserve into a clean gaseous feedstock ("syngas") for power generation as well as for the production of chemicals and clean fuels, such as synthetic natural gas or gasoline for the transportation sector. In parallel, sulfur and other problematic contaminants can be removed and/or converted into useful industrial chemicals as part of the syngas conditioning train.

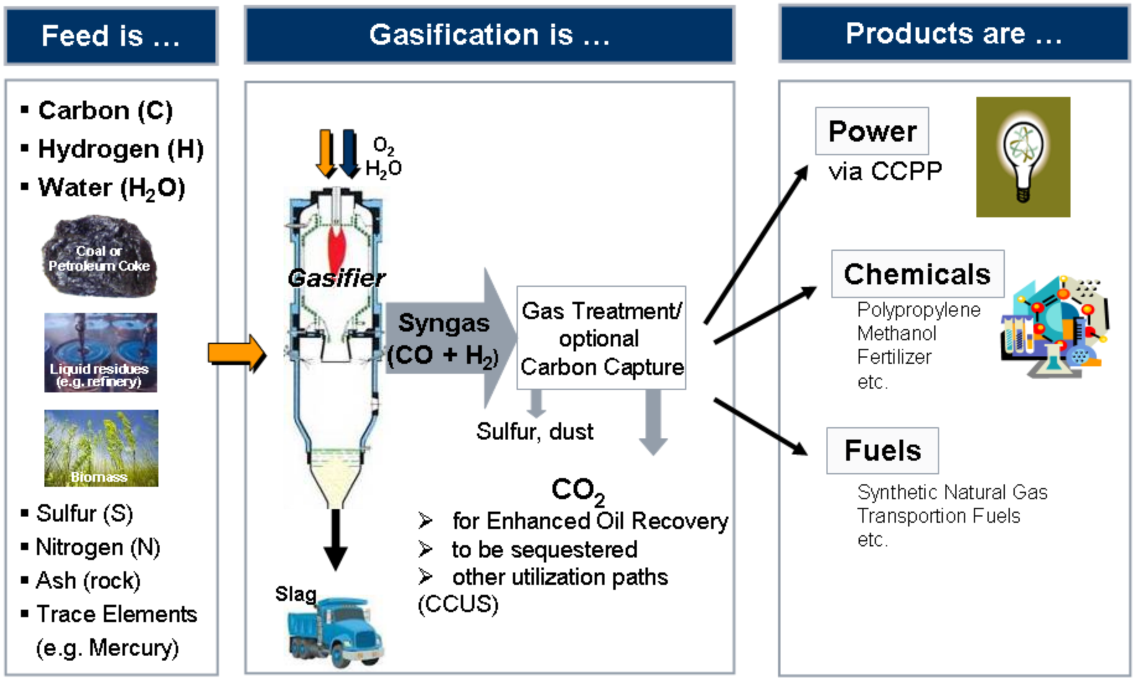
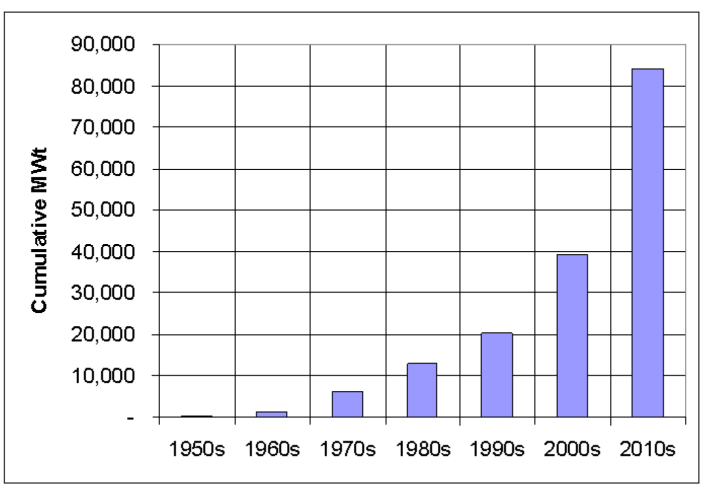


Fig. 9: Fuel and Product Flexibility – Gasification is the Key Enabler

In order to adjust the stoichiometric ratios between carbon and hydrogen needed to make chemicals and fuels, the carbon content of the syngas is reduced by converting CO to CO_2, which is removed in a subsequent step. For low-carbon power generation, typically 90% of the carbon in the syngas is removed ("pre-combustion carbon capture") and the hydrogen-enriched fuel gas is used in a gas turbine adapted to the special needs of that fuel.

The global rate of installation of gasification plants has accelerated since 2000. Around three-quarters (71%) of these gasifier are used to produce chemicals and gaseous fuels, and most of that production is in Asia. Roughly 29% of the gasifier are used to produce electric power, and almost all of that are in North America and Europe.



Source: Gasification Technologies Council *World Gasification Database*

Fig. 10: Worldwide Cumulative Gasifier Installations

For example, Siemens uses a fuel gasification concept which offers two basic solutions for a wide variety of feedstock: Gasifier that are fed by ash-forming coals (more than 3% ash content) apply a cooling screen that provides short start-up and shut-down periods and the highest component availability. Due to dry feeding, high efficiency and carbon conversion rates above 98% can be achieved. For low-ash feedstock such as petroleum coke or tars and oils, a refractory-lined gasifier design has been developed that includes a feeding system for liquids. In both concepts, the hot syngas exiting the high-temperature conversion zone is cooled by a simple and reliable full-water quench, giving produced synthesis gas an inherently high water content that is ideal for downstream CO sour shift and CO_2 capture units.

3.2 Gasification and CCPP – Power as the Main Product

In an integrated gasification combined cycle (IGCC) plant, the gasifier provides syngas and the air separation unit (ASU) provides diluent nitrogen to the gas turbine. In turn, the power island provides boiler feed water for the gasifier and in some cases also provides air from the gas turbine compressor to the air separation unit. The steam integration and, to a lesser extent, the air and nitrogen integration, offer the potential for high coal-to-power IGCC efficiencies.

However, studies and lessons learned from the early IGCC plants have reduced the attractiveness of higher efficiency in favor of improved operability. The general trend in IGCC plants is toward a lower degree of integration because the less-integrated configurations are easier to start, less complex to operate, and can use gas turbines and CCPP designs closer to standard natural gas-based designs with only minor modifications. In fact, without air integration the plant is simpler to start and operate because of reduced complexity. The ASU and gasifier do not need the gas turbines to be operating for commissioning or for normal start-up. Overall plant control concepts are simpler, the plant operates with better availability, and the design and operation of the ASU are not influenced by variations in gas turbine extraction air conditions.

Non-integration is the most flexible pathway for power production. A stand-alone gas island can produce chemicals such as methanol or synthetic natural gas (SNG) for the natural gas grid, and can be extensively used for applications such as the existing CCPP fleet. One example of such a plant is the Yinan coal-to-SNG project in Yili City, Xinjiang Province, in the People's Republic of China. The facility comprises eight Siemens SFG-500 gasifier that will produce 6,000 million Nm^3 of SNG per year. With this project, the China Power Investment Corporation is one of first major utilities in China to build a coal-to-SNG plant.

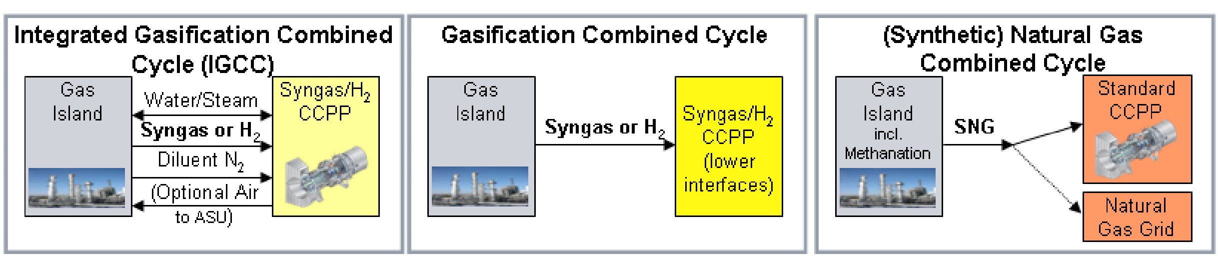


Fig. 11: Power Generation Options for Combined Gasification and CCPP

Due to well-proven, efficient gas-cleaning technologies applied upstream from the combustion, and basic development efforts such as advanced combustion of syngas and hydrogen-enriched syngas, IGCC concepts are ready for low-emissions. The early demonstration plants in Europe have already shown emissions lower than typical limits for steam power plants in Germany today.

IGCC Plant	Start-up	PM [kg/MWh$_{el}$]	NO_x [kg/MWh$_{el}$]	SO_x [kg/MWh$_{el}$]
Nuon Buggenum (*) The Netherlands	01/1994	0.005	0.318	0.200
Elcogas Puertollano (*) Spain	12/1997	0.020	0.399	0.068
Typical SPP Germany	2010	0.030	0.530	0.400

Table 1: Emissions of existing coal-based units. (*) Source: J. Ratafia-Brown et al.

3.3 Gasification for More Products - Polygeneration

The chemical processing aspects of combined gasification and power plants make them ideal to be extended for polygeneration. The term “polygeneration” refers to the simultaneous production of two or more useful products.

This plant is at least partly inherently carbon capture ready as a consequence of gas conditioning for the methanation process. Instead of emitting the CO_2 the CO_2 emissions from this plant could be sequestered or used, for example, for enhanced oil recovery.

The power block, which includes one or more gas turbines, one or more HRSGs, and a steam turbine, can be sized to export power to the grid or to provide only enough power to run the plant auxiliaries, eliminating the need to purchase power from the grid.

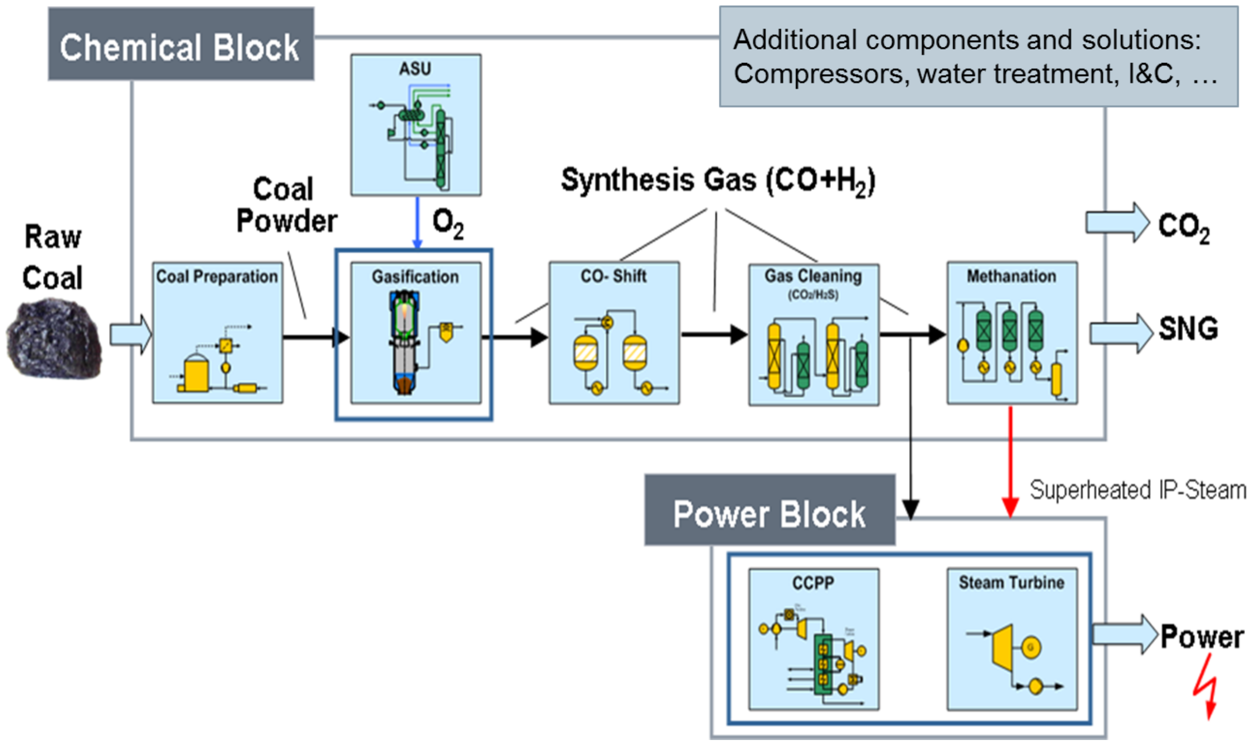


Fig. 12: Polygeneration – Combined Production of Chemicals/Fuels and Power

The economics of polygeneration depend on local market conditions, including the cost of feedstock as well as the value of potential products. For example, one ton of coal could be converted to either 400 Nm^3 of SNG, 2.5 MWh of electric power, or one ton of ammonia. Assuming typical market prices for these products, the production of ammonia would result in three to six times the revenue per ton of coal compared to SNG or power production. Individual business cases can lead to different results worldwide, and power production is typically used to meet the demand of the chemical block or refinery even if it is more expensive than over-the-fence power.

The Texas Clean Energy Project is a good example of a polygeneration plant. The facility will convert 1.8 million tons per year of low-sulfur Powder River Basin coal into 195 net megawatts of power to the grid, 2.5 million tons per year of CO_2 for enhanced oil recovery, and 710,000 tons per year of urea for fertilizer. The plant is located directly above the Permian Basin, which is the site for enhanced oil recovery.

With 90% CO_2 capture, the CO_2 emissions from this plant will be only 20-30% of the CO_2 that would be produced by the same sized combined cycle plant operating on natural gas. Construction is targeted to start in the beginning of 2013, leading to commissioning and commercial operation three to four years later.

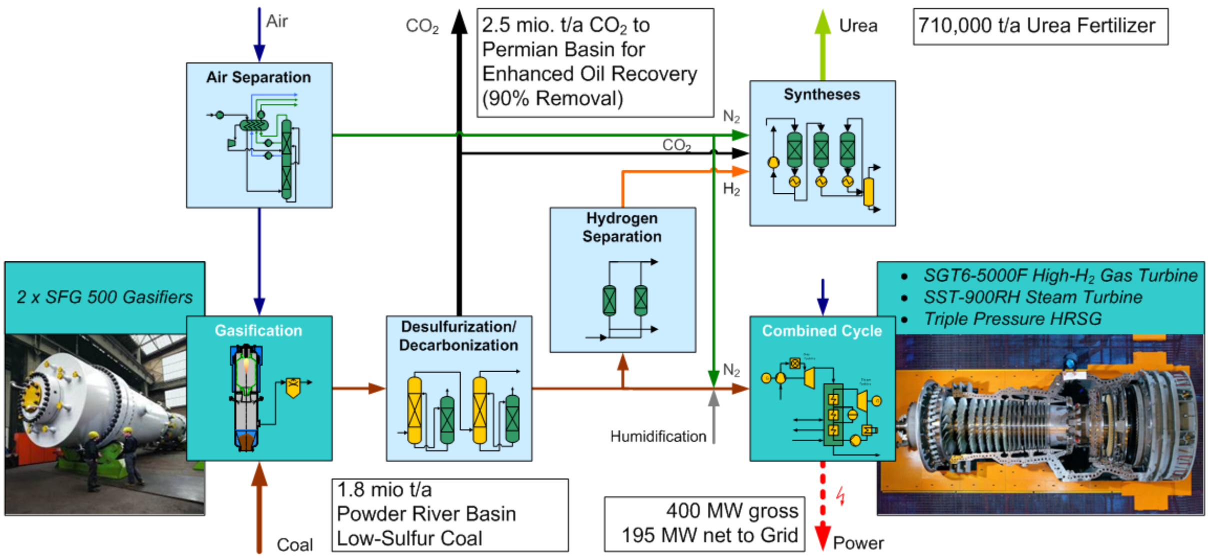


Fig. 13: Typical Polygeneration on Coal - Summit Texas Clean Energy (Source: Siemens)

Another example of a polygeneration plant is one that uses all of its products within the refinery. Refinery residues could feed the gasification and chemical block to produce fuel gas and steam for the power block along with hydrogen to meet the refinery need for hydrogen to make lighter products. The power block is sized to generate only the power that is used internally by the refinery and other auxiliaries, but not power for export.

IGCC and polygeneration facilities are currently viable, but further development efforts are needed for the core components as well as for the overall plant concept and design. Examples are:

- Advanced dry feeding systems,
- Minimizing black water recirculation and applying advanced water treatment technologies,
- Scaling or adapting the gasifier size to optimally match the GT product portfolio,
- Increasing turndown capability and load ramping capability to fulfill grid code requirements,
- Optimizing the plant equipment arrangement (footprint),
- Optimizing the heat integration between the chemical island and the power island,
- Improving the utilization of low-temperature excess heat,
- Achieving zero liquid discharge,
- Optimizing the CO shift concept to reduce raw gas water content and maximize HP/MP steam production to improve efficiency, and
- Developing an advanced master controller.

3.4 The Future – Coal-to-Chemicals Integrating Renewable Energy

Power from renewable energy is becoming an increasingly important part of the changing energy system, but it creates challenges for technologies that store electricity. Balancing fluctuating solar or wind power for long-term periods - days or even months - requires the conversion of electrical energy into chemical energy. The production of hydrogen from water using electrical electrolysis is a prominent solution for high-capacity energy storage, but a new infrastructure would be needed to cost-effectively and safely buffer and handle large amounts of hydrogen.

An alternative solution would be to store hydrogen via conversion into hydrocarbons. All routes for generating chemicals or fuels from coal via gasification suffer from a deficit of hydrogen in the feedstock related to the carbon content. Thus, the concepts as described are excellent for indirectly storing renewable power as valuable products such as SNG in the existing carbon-based energy landscape.

For example, a state-of-the-art coal-to-SNG plant emits a considerable amount of carbon (as CO_2) to adjust the stoichiometry needed to synthesize methane. By implementing renewable-powered electrolyzer modules, this plant could go "green" step-by-step. In addition to enriching the synthesis gas with hydrogen, the concept includes the replacement of oxygen from the conventional cryogenic air separation unit by oxygen that is produced as a by-product from water electrolysis. If there is sufficient green power together with mature, cost-effective electrolytic technology, the process units for air separation, water-gas shift reaction, and CO_2 separation/compression/sequestration could be reduced in capacity or finally omitted.

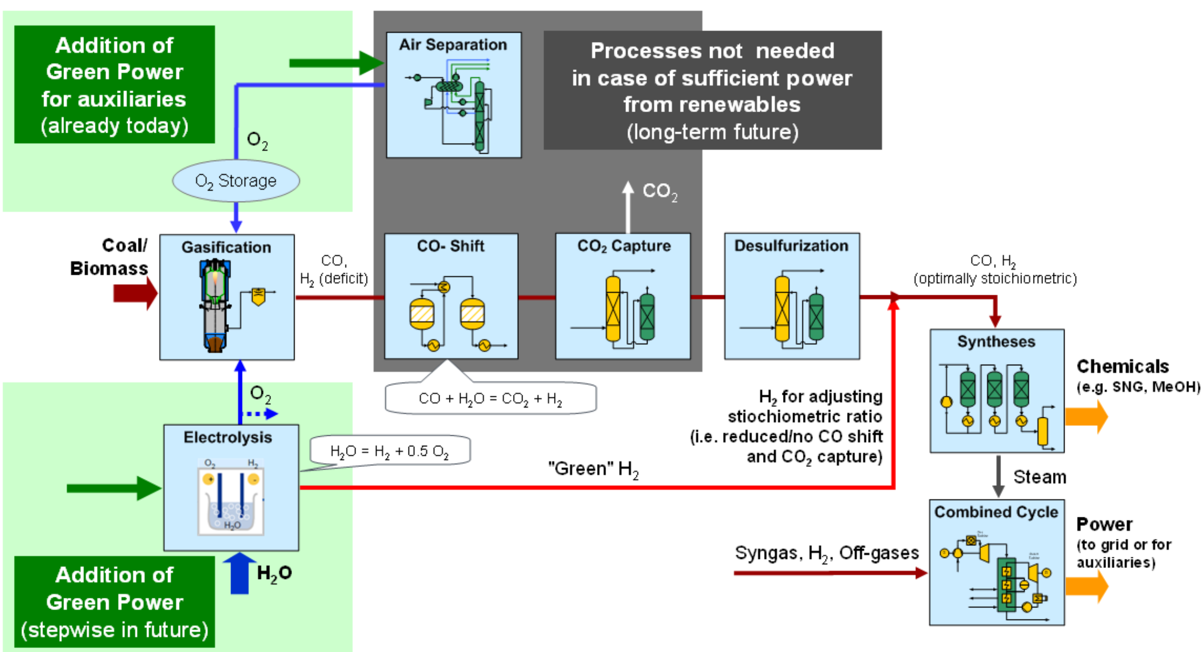


Fig. 14: Stepwise Integration of Renewable Energy into Polygeneration Concepts

The proposed CO-based approach could already be realized in existing synthesis plants, compared to the other route for storing green hydrogen as hydrocarbons, which is based on the synthesis of hydrogen with captured CO_2 (for example from post-combustion carbon capture).

Moreover, due to its capability to flexibly shift between chemical and power production, gasification-based polygeneration offers the opportunity to use renewable energy for auxiliary power consumption in order to maximize chemical production and make it more environmentally benign. On the other hand, if renewable energy is not available, polygeneration can support grid stability by maximizing electrical output, which can be done on short notice according to grid requirements. Further, since low-grade fuels are very cost effective and their prices do not fluctuate because of fuel supply requirements, it offers a highly interesting solution to balance the increasing and fluctuating renewable energy supply. It also provides the capability of oxygen storage, which can be used to minimize auxiliary power consumption from fossil fuels and to bridge the time until renewable energy is available.

4. Carbon Capture and Storage (CCS)

It is projected that once CCS technologies are validated and their associated costs are proven through the operation of large-scale demonstration plants such as within the EU CCS demonstration program, CCS will become cost-competitive with other low-carbon energy technologies.[1]

Among the various available CCS technologies, post-combustion capture is the most versatile and the best adapted to the requirements of power plant operators. The levelized cost of electricity (LCOE) of fossil-fired power plants equipped with carbon capture is competitive with other clean power generation technologies and, due to high availability and flexibility, is also an attractive complement to fluctuating power generation from renewable energies.

With the application of carbon capture for the production of CO_2 for enhanced oil recovery gaining importance, processes need to be adapted to the specific needs of gas-fired power plants that are predominant in the relevant markets. Several possible cost-reduction measures have been identified that make the Post Combustion Capture processes more cost-effective for gas-fired power plants and that offer significant potential for cutting the costs per ton of CO_2.

According to the International Energy Agency (IEA), CCS must provide 20% of the global cuts in CO_2 emissions required by 2050.[2]

4.1 Market Requirements

The forecast costs for carbon capture and storage for the first commercially operated plants after 2020 are estimated to range between 35 and 90 €/t CO_2, the capture plant contributing at least half of the costs (see XX). With very low CO_2 certificate prices in the EU trading scheme - currently around 5 €/t CO_2 (European Emission Allowances)[3], there is still a large gap between the costs of carbon capture and what power plant operators would be ready to pay for it. This means that carbon capture and storage without commercial use of the CO_2 such as for enhanced oil recovery is not commercially viable for the moment. Unless the CO_2 can be commercially used (CCUS – Carbon Capture, Utilization and Storage) or CO_2 emission rights

[1] Zero emissions platform (ZEP): "The Costs of CO2 Capture, Transport and Storage - Post-demonstration CCS in the EU," July 2011

[2] Zero emissions platform (ZEP): "ZEP statement on CCS cost reports: Post 2020, CCS will be cost-competitive with other low-carbon energy technologies"

[3] Source: www.eex.com

become much more restricted, fossil-fired power plants will continue to be operated without carbon capture.

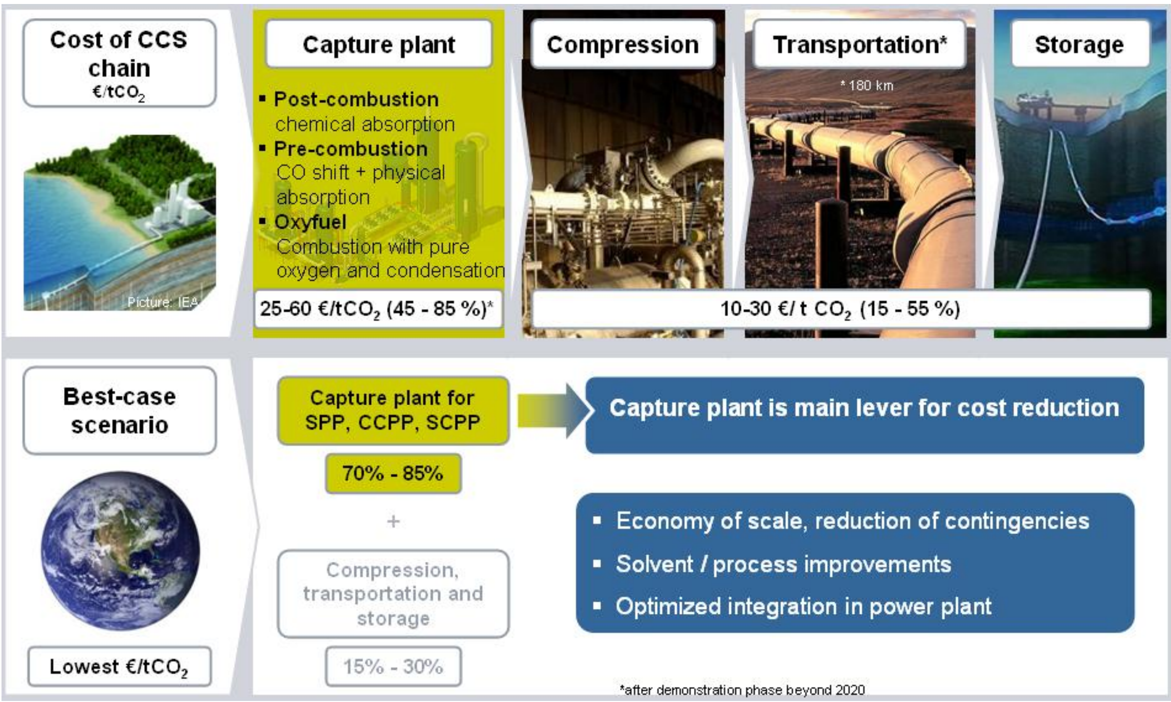


Fig. 15: Total cost of Carbon Capture and Storage with main cost drivers

Depending on the location of the storage site (onshore or offshore) as well as the transport distance and therefore pipeline length, costs for transport and storage can vary widely. In addition, permissions also differ for onshore and offshore storage. While onshore storage is cheaper than offshore storage, the population of several countries such as Germany is opposed to living near a CO_2 storage site.

Based on long experience in the U.S., the transport of CO_2 in pipelines is not critical. The risks are known and easily managed. Costs can be reduced by early strategic planning of large-scale CO_2 transport infrastructure, such as clustering CCS plants with a transport network. [4]

CO_2 storage in depleted oil and gas fields as well as in saline aquifers has been proven feasible through the operation and subsequent monitoring of CO_2 storage sites both onshore and offshore. Storage in depleted oil and gas fields is cheaper than in deep saline aquifers and, logically, large reservoirs are cheaper to operate than smaller ones.

At the moment, the main obstacle for market introduction is the cost of capture, mainly driven by CO_2 capture plants. However, compared with other CO_2 mitigation options such as replacing fossil-fired power plants with renewable energy sources, carbon capture becomes commercially interesting. The levelized cost of electricity (LCOE) for combined cycle power plants as well as steam power plants with carbon capture is lower than for offshore wind and photovoltaic plants. The only other CO_2-free power generation options with lower LCOE are nuclear and onshore wind power plants.

[4] Zero emissions platform (ZEP): "The Costs of CO2 Capture, Transport and Storage - Post-demonstration CCS in the EU," July 2011

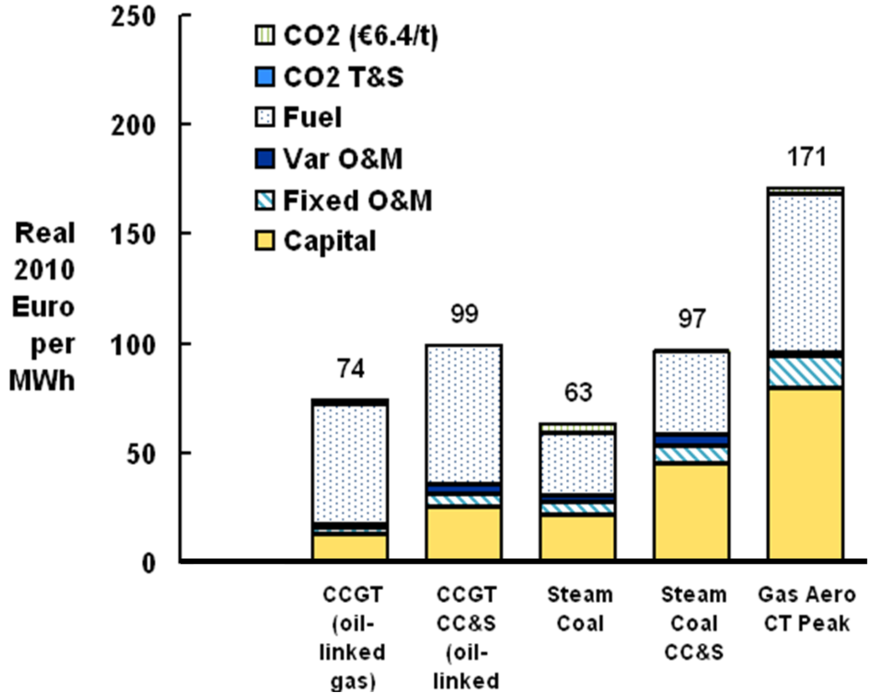


Fig. 16: Comparison of levelized cost of electricity (LCOE) for various fossil power plant types (source: IHS CERA)

Furthermore, it is projected that CCS costs can be further reduced in the years to come based on large scale demonstration of the technologies. Fossil-fired power plants with carbon capture can thus be seen as an ideal low-CO_2 back-up and complement to the use of renewable energy sources: Energy from power plants with CCS is available when needed and has very low CO_2 emissions.

Due to the impact of an increasing portion of renewable energy sources in the overall energy mix, fossil-fired power plants are required to be operated more and more flexibly in peak load operation, i.e. with low operating hours per year. This conflicts with the interests of CCS, since power plants with CCS require mid- to base-load operation to be competitive due to their higher investment costs. Further investigation for better operation conditions as well as market incentives are necessary to best place CCS power plants in the energy market.

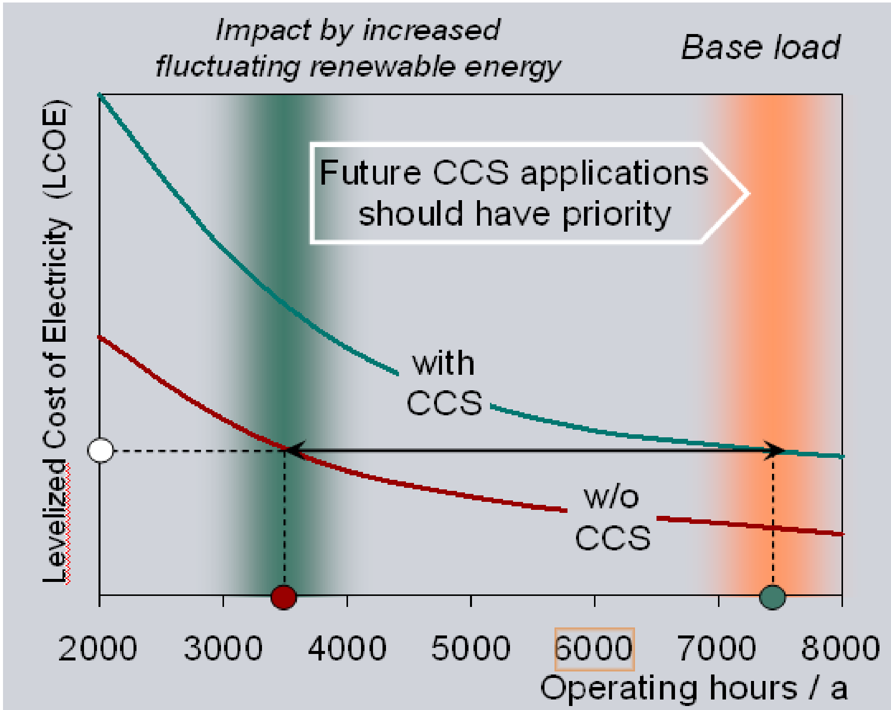


Fig. 17: Sensitivity of LCOE by operating hours for fossil-fired power plants with CCS

The EU Zero Emissions Platform (ZEP) came to the conclusion that base-load demand is likely to decrease while the need for balancing power will increase in order to complement intermittent power sources. They therefore assume the additional need for energy storage capacity and balancing power, combined with operating thermal power plants at lower utilization, will increase the overall cost of electricity.[5]

All these market requirements have an impact on the technology development to find the best suitable solution to make CCS power plants attractive for the future energy market.

[5] Zero emissions platform (ZEP): "ZEP statement on CCS cost reports: Post 2020, CCS will be cost-competitive with other low-carbon energy technologies"

4.2 Carbon Capture Technologies

There are three main technology options for carbon capture: Oxyfuel combustion, pre-combustion capture and post-combustion capture. In oxyfuel combustion, the fuel combustion is done with pure oxygen rather than air; pre-combustion capture entails decarbonization of the fuel gas produced in a fuel gasifier and combustion of the resulting hydrogen gas. In post-combustion capture processes, the CO_2 resulting from fuel combustion in a boiler or gas turbine is washed out of the flue gas before it is released to the atmosphere.

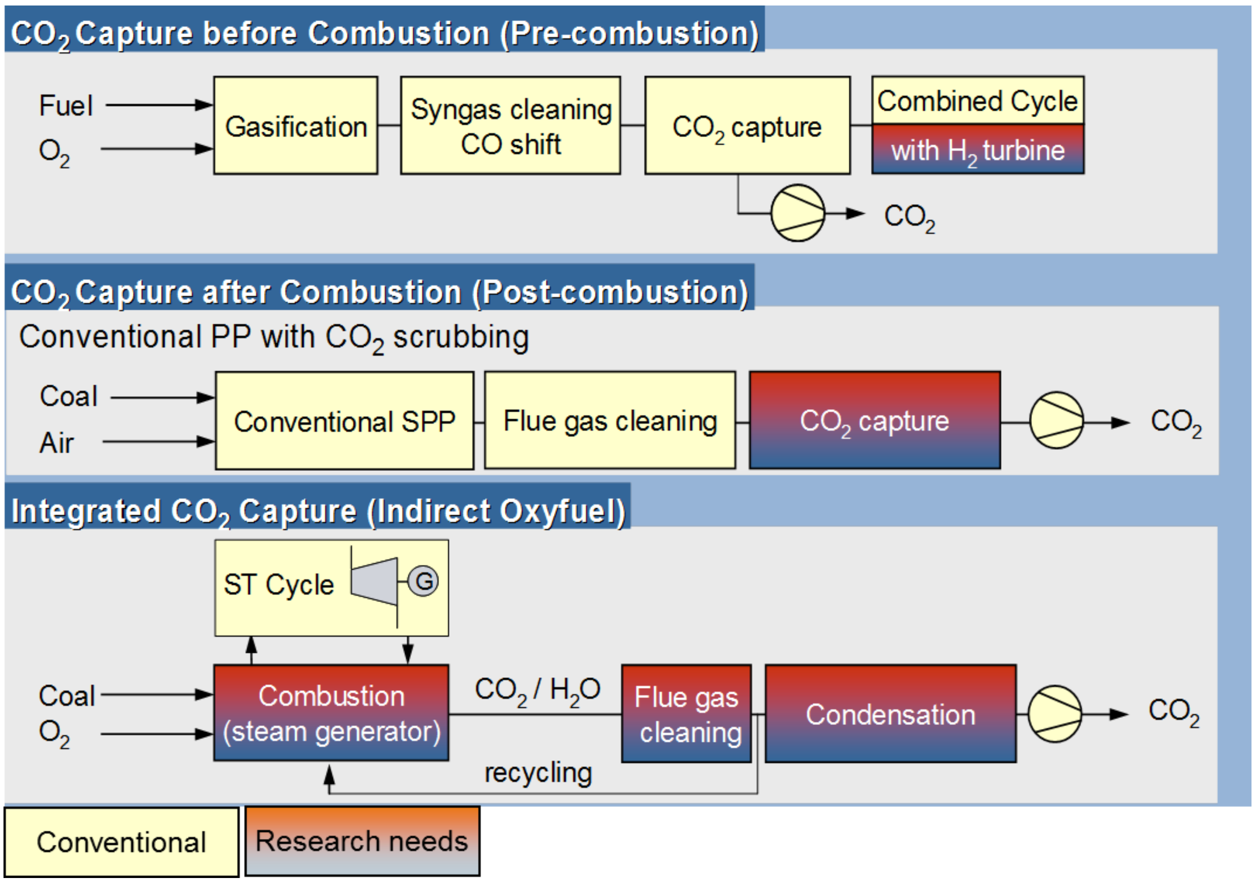


Fig. 18: Schematic representation of pre- and post-combustion carbon capture

All three technology paths are being persued in pilot and demonstration projects throughout the world and each has certain advantages in specific applications.

Pre-combustion capture is most suitable for new IGCC power plants combined with the polygeneration of chemical products. In addition to a combined cycle power plant equipped with a gas turbine running on hydrogen instead of natural gas, the set-up requires a fuel gasification plant and a chemical plant with several cleaning and conversion steps for the synthesis gas produced in the gasifier, including a CO_2 capture plant that uses physical absorption.

Oxy-fuel combustion is the process of burning a fuel using pure oxygen instead of air as the primary oxidant. Since the nitrogen component of air is not heated, fuel consumption is reduced, and higher flame temperatures are possible. Historically, the primary use of oxy-fuel combustion has been in welding and cutting of metals, especially steel, since oxy-fuel allows for higher flame temperatures than can be achieved with an air-fuel flame.

There is currently research being done in firing fossil-fueled power plants with an oxygen-enriched gas mix instead of air. Almost all of the nitrogen is removed from input air, yielding a stream that is approximately 95% oxygen. Firing with pure oxygen would result in too high a flame temperature, so the mixture is diluted by mixing with recycled flue gas, or staged combustion. The recycled flue gas can also be used to carry fuel into the boiler and ensure adequate convective heat transfer to all boiler areas. Oxy-fuel combustion produces approximately 75% less flue gas than air fueled combustion and produces exhaust consisting primarily of CO_2 and H_2O. The justification for using oxy-fuel is to produce a CO_2 rich flue gas ready for sequestration.

A major advantage of post-combustion carbon capture processes is that they can be used both for new power plants and for retrofitting existing power plants. Post-combustion carbon capture is very flexible in terms of fuels and the combustion process itself, which makes it more versatile than the other two technology options. A post-combustion capture plant can be designed either for the complete flue gas stream or for only part of it. In addition, power plants equipped with post-combustion capture can still be operated without the capture plant, i.e. if required, the capture plant can be bypassed. This option does not exist for the two other technology paths. Post-combustion capture is therefore the most suitable and flexible option for power generation and at the same time the most benign solution.

Example: PostCap™ Technology

Siemens has developed a proprietary post-combustion carbon capture technology named PostCap™. The primary targets for Siemens in the development of the PostCap™ process were to meet most stringent environmental requirements without compromising the economics. At the same time, Siemens as a power plant provider followed the principle that "a power plant remains a power plant;" it was considered that the operating staff at the power plant can handle the plant operation according to their accustomed safety standards.

Siemens therefore decided in favor of amino acid salts (AAS) as the basis for the process because the physical and chemical properties of AAS have advantages compared to amine solvents with respect to solvent handling, plant operation and operating permissions. AAS are chemically stable and naturally present. They have ionic structure in the solution, which provides substantial advantages such as virtually zero vapor pressure, therefore nearly zero solvent emissions, high absorption capacity, negligible degradation, low energy consumption and environmental sustainability compared to other amine-based technologies in this field. In addition, amino acid salts have a low sensitivity to oxygen degradation due to their structure. Since salts do not have vapor pressure, they are very easy to handle: They are not inflammable or explosive and do not present an inhalation risk. In addition, they have a high biodegradability, are nontoxic and environmentally friendly.

The Siemens PostCap™ technology utilizes selective absorption of the CO_2 from the flue gas and subsequent desorption, thus gaining nearly pure CO_2. An improved process configuration is applied, resulting in a significant reduction of energy demand. The low solvent degradation through O2 contained in the flue gas as well as through elevated temperatures leads to reduced solvent consumption of the process. The low energy demand for the solvent regeneration (i.e. 2.7 GJ thermal per ton of CO_2 captured) and the possibility of running the process at various temperature and pressure conditions makes the proposed design exceptional. The solvent is nontoxic, biodegradable and has negligible vapor pressure. As a result, solvent losses and emissions in the cleaned flue gas and the separated CO_2 stream are below practicable detection limits.

The main components in the CO_2 capture plant (i.e. PostCap™ Plant) are the absorption and desorption column. The absorber and desorber column internals in particular are essential for the efficient and reliable operation of the carbon capture plant. A broad range of column internals has been evaluated during the past years to select the optimal internals for the absorption and desorption process. Process design parameters such as temperature etc. are set so that the precipitation of solid salts is avoided. During more than 7,000 hours of pilot operation, no plugging of trays or packings was observed.

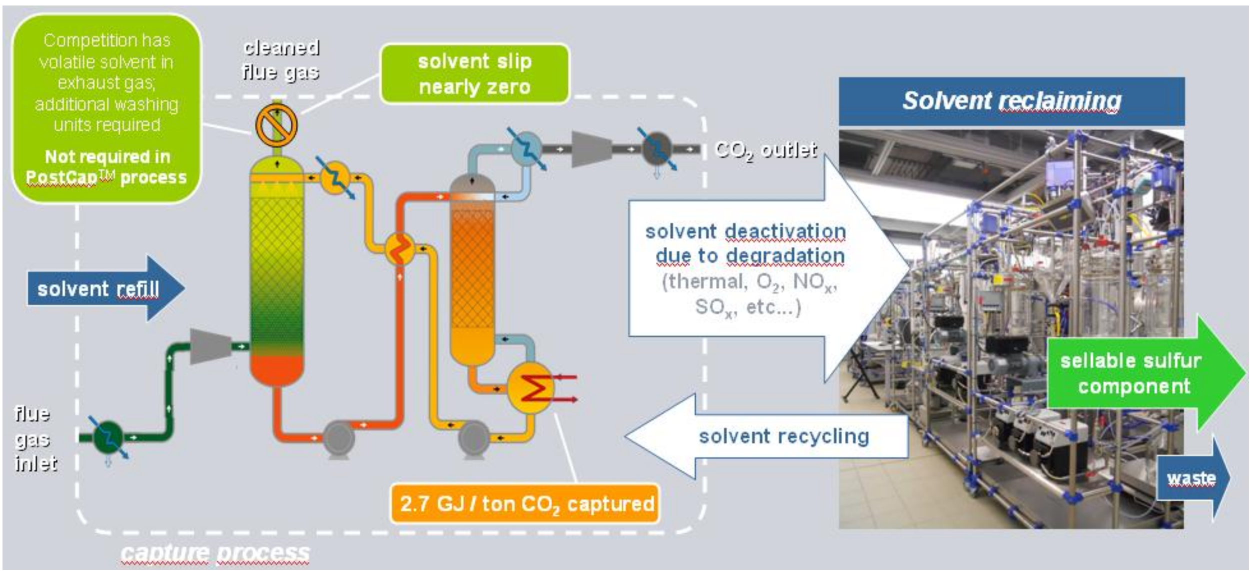


Fig. 19: PostCap™ process with solvent reclaiming (source: Siemens)

The standard desorber design considers atmospheric pressure conditions at the desorber outlet. If required, the design can be changed to elevated pressures. A CO_2 compressor would bring the gaseous CO_2 up to higher pressure for further processing. Appropriate units for CO_2 purification are available to meet needs such as pipeline transportation and storage with respect to water and oxygen content.

A great advantage of amino acid salt solvents is that the solvent does not evaporate and therefore is not emitted with the cleaned flue gas as a solvent slip (below detection limit of even very sensitive measurement instruments). Since the solvent is chemically and thermally very stable (see subsequent paragraphs), only very small amounts of solvent degradation products are emitted. These occur in a much lower amount than for amine-based solvents and comply with the most stringent environmental requirements.

The aqueous amino acid salt solution used as solvent exhibits low thermal sensitivity, so that solvent degradation is relatively low. The thermal stability of the solvent has been proven in short- and long-term investigations. Amino acid salts have an ionic structure and therefore a low susceptibility to oxygen degradation. Oxygen dissolved in water tends to negative loading and is thus hindered in degrading the dissolved anion of the amino acid salt. This results in a high chemical stability.

Nevertheless, due to the fact that in post-combustion processes large quantities of flue gas are treated over a long period of time, even very small amounts of trace components which are contained in the flue gas as secondary components (like sulfur- or nitrogen oxides) could lead to a noticeable accumulation of secondary products in the solvent pump-around. These secondary products (heat-stable salts, HSS) also have negligible vapor pressure and are therefore not evaporated in the desorber. In order to prevent an accumulation in the solvent cycle, these components must be eliminated by continuously removing a minor part of the solvent in a purge stream. Therefore, a purge stream of the cold solvent is directed to a reclaimer unit, where secondary products are removed. The removed solvent is replaced by the same amount of fresh solvent or of regenerated solvent from the reclaiming operation.

Reclaimer concepts for amine-based solvents are not suitable for amino acid salts since they rely on evaporating the active component. Since salts cannot be evaporated, however, Siemens has developed a proprietary process for reclaiming amino acid salt solvents.

The solvent reclaiming unit ensures that the utilization of solvent is maximized and solvent residues are minimized, and thus contributes to the substantially low operational costs. Furthermore, through the reclaimer, sulfur oxides contained in the flue gas are converted to a marketable fertilizer product. Therefore, the requirements for limiting the SOx levels upstream of the absorber are less strict compared to other amine-based capture technologies.

The main investment cost contributors for a carbon capture plant are the absorption columns (due to the large flue gas volumes), the CO_2 compressor, the flue gas cooler (direct contact cooler, DCC) and the desorption column. In addition, high purity of the produced CO_2 is generally required, so that a CO_2 purification step must be included. The main cost reduction levers and thus improvement potential identified for Siemens' carbon capture process are therefore the absorption and desorption columns as well as the direct contact cooler.

Fig. 20: 3D view of a gas-fired combined cycle power plant with Siemens PostCapTM Plant with two absorption lines

The example shows a 700-MW natural gas-fired combined cycle power plant with 4,500 TPH flue gas with 6%wt CO_2. The scheduled CO_2 production is 1,800,000 TPA of CO_2 @ 200 bar. Siemens has done a FEED study for this project with the aim of retrofitting a single-train PostCap^{TM} Plant with two absorption lines to an existing power plant.

This 3D views shows the large dimensions of the direct contact cooler, the possible omission of which is described as a cost reduction option in the following section.

4.3 Challenges for Carbon Capture Plants

As a result of available commercial boundary conditions, CO_2 capture for use in enhanced oil recovery (EOR) projects has recently grown in importance. Post-combustion capture technology is increasingly being applied to CO_2 capture from gas-fired power plants. There are different impacts and challenges when implementing CO_2 capture at gas-fired power plants in comparison to coal-fired steam power plants. Flue gas from gas-fired power plants is particularly challenging due to several factors: The CO_2 concentration in the flue gas is significantly lower than for coal-fired power plants, while the O_2 concentration is much higher. In addition, the flue gas mass flow per MW_{el} is approximately 60% higher in gas-fired power plants.

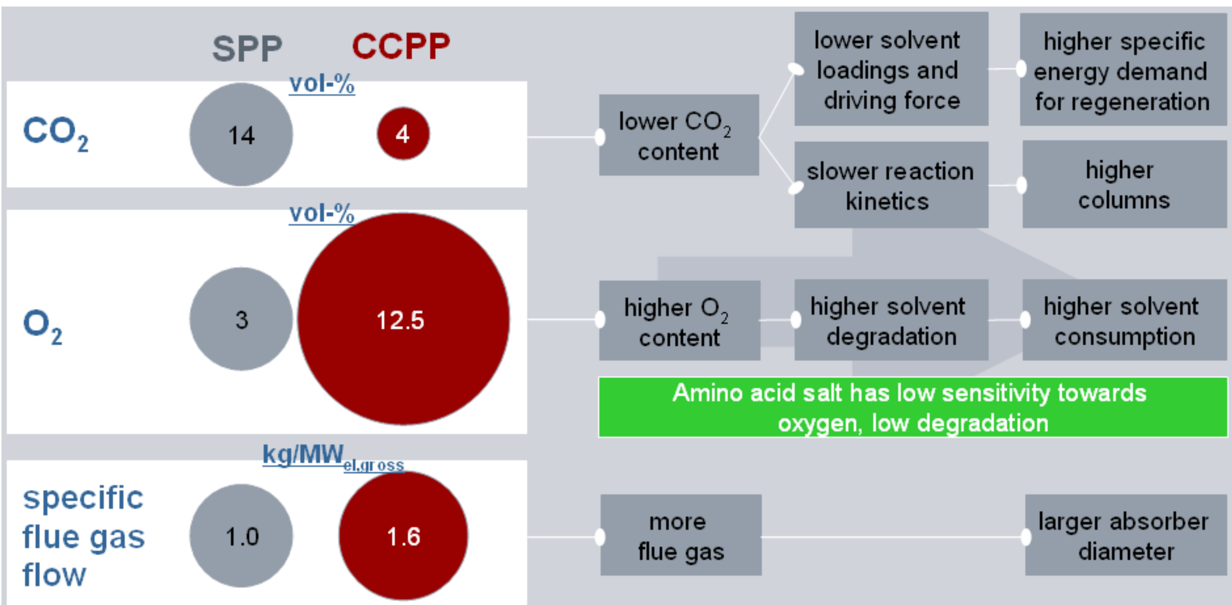


Fig. 21: Major impacts and challenges for post-combustion carbon capture with gas fired combined cycle power plants (CCPP) vs. steam power plants (SPP)

The lower CO_2 content implies lower solvent loading and slower reaction kinetics, leading to a higher specific energy demand for regeneration and higher absorption columns. On the other hand, the higher O_2 content in the flue gas leads to a higher solvent degradation and therefore to an increased reclaiming need and solvent consumption. Yet, amino-acid salt solvents are especially well-suited for high O_2 contents since they have low susceptibility to oxygen-induced degradation due to their chemical structure. The higher specific flue gas mass flow makes it necessary to use larger absorber diameters.

Overall, capture costs per ton of CO_2 are thus higher for gas-fired power plants than for coal-fired power plants. Yet, countries where CO_2 can be commercially used for enhanced oil or gas recovery usually operate gas-fired power plants, since the fuel is locally available. The reduction of costs per ton of CO_2 captured is therefore the main target for making carbon capture more attractive in regions such as the Middle East.

4.4 Cost Reduction Potential

As a result of lower CO_2 and higher O_2 concentrations as well as larger flue gas quantities, the specific cost for separating a certain amount of CO_2 is significantly increased compared to coal-fired power plants. In order to be able to implement a capture project successfully in the market, the capture cost needs to be dramatically reduced. In our own investigations based on FEED studies for various customers, Capital Expenditures (CAPEX) in particular have been identified as the major lever for cost reduction. However, Operational Expenditures (OPEX) must also be taken into account since both cost shares are associated with one other.

Several process elements can be improved or modified in order to enhance cost effectiveness. The most promising cost reduction potential has been found in the following upgrades:

- Reduction of required component sizes and capacities by improving capture chemistry and/or reducing concept complexity
- Innovative cycles, such as improving energy utilization and/or flue gas properties (e.g. increase of partial CO_2 pressure)

In the following the cost reduction potential is exemplified with specific possible measures.

a) Reduction of concept complexity and component sizes:

- Solvent activators:

Additional CAPEX savings of up to 5-10 % can be achieved by applying enhanced solvent activators. This would accelerate reaction kinetics which would result in lower heights for the absorber and desorber columns. Initial results show a reduction potential of column heights of about 20 % by applying an enhanced activator dedicated to the AAS solvent used in the PostCap™ process.

- Construction materials:

And additional 5 - 10% CAPEX savings can be achieved by further optimizing construction materials used in the capture plant. Comprehensive long-term investigations are under way to judge the applicability of lower-grade materials for PostCap™. With the qualification of a number of materials for different plant parts and equipment, material selection can be optimized with regard to availability and market prices. Where reasonable, the adaptation of certain operating and design parameters of the PostCap™ process is taken into account to enable the use of cheaper materials.

- Solvent precipitation:

Conventionally, absorption/desorption processes will be operated in liquid phase only; i.e. process conditions will be chosen in such a way that no reaction products of the CO_2 with solvent precipitate. However, precipitation enables higher rich loadings and a more efficient desorption. The reduced energy demand results will directly reduce CAPEX due to smaller desorber diameters and heat exchangers. Nevertheless, a process including a precipitation step would require special equipment that might increase CAPEX. As a result of a conceptual process evaluation, OPEX can be decreased by about 20% and thus decrease total CO_2 capture cost.

b) Innovative cycles:

As a result of the lower CO_2 content in the exhaust gas of gas fired power plants, specific costs for the production of one ton of CO_2 are high in comparison to coal-fired power plants. It is therefore obvious that these costs can be decreased by increasing the CO_2 concentration.

Several concepts have been and will be evaluated utilizing processes such as the supplementary combustion of flue gas. Besides increasing CO_2 content, this would decrease the oxygen amount contained in the flue gas and therefore the degradation of solvent.

In the past, CO_2 capture was mainly foreseen as a retrofit to existing power plants. As an experienced supplier of power plants and at the same time as technology owner of the PostCap™ technology, Siemens undertook comprehensive studies for optimally integrating the capture plant into the power plant environment so waste heat can be utilized as efficiently as possible. Additional potential for decreasing CAPEX and OPEX was identified by modifying the power plant so the integration of the carbon capture facilities can be optimized. As a result, the total cost for operating the power plant and capture plant entity can be reduced. Possible concepts hint at a better utilization of sensible heat contained in the flue gas, such as desorber heating or increasing the flue gas pressure.

As a preliminary result, specific CO_2 separation costs at gas-fired power plants can be decreased by 10% to 20%.

References

1. Zero emissions platform (ZEP): ”The Costs of CO2 Capture, Transport and Storage - Post-demonstration CCS in the EU,” July 2011

2. IHS Cera: Levelized cost of electricity (LOCE) for various fossil power plant types