



CO₂ CAPTURE TECHNOLOGIES

PRE COMBUSTION CAPTURE
JANUARY 2012



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PRE COMBUSTION CAPTURE

Introduction

The oil, gas and chemical industries have been separating CO₂ from gas streams for decades. In most cases the CO₂ is removed in order to meet the required downstream product requirements, whether natural gas, hydrogen or chemicals. The term pre-combustion capture has come into use relatively recently mostly in the context of gasification based power plants, particularly IGCC, where, in anticipation of requirements to limit CO₂ emissions, plant designs have been developed to convert the gas produced from gasification (henceforth referred to as 'syngas') to hydrogen and CO₂ and to remove the CO₂ from the syngas stream prior to the combustion of the hydrogen rich gas in the gas turbine.

Pre Combustion Capture Technology¹

In natural gas processing, natural gas reforming, gasification and IGCC the ultimate capture of the CO₂ is currently accomplished under pressure by an acid gas removal (AGR) process of absorption in a solvent followed by regenerative stripping of the rich solvent to release the CO₂ which with subsequent compression can be sent to sequestration or supplied for EOR.

There are two major generic types of 'acid gas' (i.e., CO₂, H₂S, COS) removal (AGR) solvents – chemical and physical.

Chemical Absorbents

Chemical absorbents (e.g., MDEA and other amines) react with the acid gases and require heat to reverse the reactions and release the acid gases. These processes generally have lower capital for AGR than physical solvents, but use larger amounts of steam-heat for solvent regeneration.

Physical Absorbents

Physical absorbents (e.g., Selexol, Rectisol) dissolve acid gases preferentially with increasing pressure. The absorbed acid gases are released from the solvent when pressure is decreased and temperature is increased. Significantly less steam-heat is required for solvent regeneration than with chemical solvents. The Rectisol process, which uses chilled methanol, generally has a higher capital cost, but provides the most complete removal.

The pre-combustion removal of CO₂ from syngas has some thermodynamic advantages over PCC. Natural gas processing, reforming and gasification are conducted under pressure (typically > 40 bar) where the higher partial pressure of CO₂ enables the use of a physical solvent (e.g. Selexol) that enables some of the CO₂ to be regenerated at pressure through a series of flash drums thereby reducing the auxiliary power required for CO₂ compression. The efficiency penalty for adding PCC to SCPC is 10-11% points in efficiency whereas the penalty for the addition of pre combustion capture to an IGCC is generally 7-8% points.

A generic process flow diagram for the acid gas removal section of an IGCC plant designed for CO₂ capture is shown in Figure 3-1. The first absorber/stripper section is for the removal of a H₂S-rich stream that is usually sent to a Claus unit for recovery of elemental sulphur for sale. The sulphur free gas is then sent to a second absorber for removal of the CO₂ and the hydrogen rich syngas is sent to the gas turbine power block. The CO₂ rich solvent is sent to a stripper for solvent regeneration and the stripped CO₂ is dried and compressed for transportation and storage.

¹ Engineering Economic Evaluations of Advanced Coal Technologies with Carbon Capture and Storage -2011. EPRI Report #1022025. G. Booras June 2011

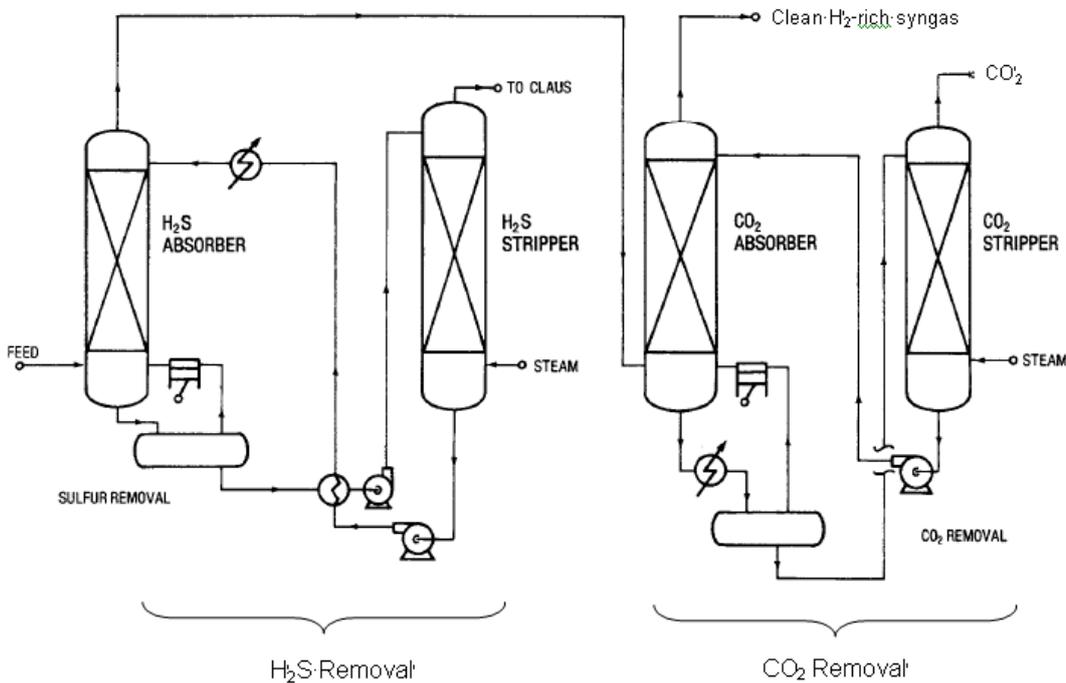


Figure 3-1 Typical IGCC AGR Process Arrangement for CO₂ Capture

Typically all the solvents can accomplish >90% CO₂ removal, but the overall percentage of capture depends on the amount of water-gas shift conducted. For a 600 MW IGCC plant the space requirements for the water-shift reactor(s), CO₂ removal, drying, and compression are similar for all solvent options, about 0.6-0.8 hectares.

Pre-Combustion Capture Applications

CO₂ Capture from Natural Gas

Much of the World's sources of natural gas contain CO₂ and Hydrogen Sulfide (H₂S). The H₂S, and in many cases the CO₂, must be removed to meet the purity requirements of natural gas pipelines and for the production of Liquefied Natural Gas (LNG). The H₂S and CO₂ can each be removed separately or together (bulk removal) from the natural gas through the use of one of several commercially available AGR processes. At most of the currently operating natural gas processing plants the H₂S is converted to elemental sulphur for sale and the captured CO₂ is vented. However there are several projects where the CO₂ is compressed for sequestration or for use in Enhanced Oil Recovery (EOR).

CO₂ Capture from Natural Gas Reforming and Partial Oxidation

Three processes - Steam Methane Reforming (SMR), Autothermal Reforming and Partial Oxidation (with oxygen) - are widely used commercially for the production of hydrogen and chemicals such as ammonia, methanol etc from natural gas. These processes can also be used with refinery gas, propane, butanes or naphtha as the feed. All three processes produce a syngas containing hydrogen, carbon monoxide (CO), CO₂ and excess steam which is cooled and passed through a catalyst bed where the CO is reacted with steam to produce hydrogen and CO₂ (known as a shift reactor which produces shifted syngas) The CO₂ can then be removed from the shifted syngas by using currently commercially available AGR processes. Most of the CO₂ from these plants is currently vented. However in plants that produce hydrogen for ammonia manufacture the co-produced CO₂ is sometimes used to react with ammonia to produce urea.

There are a few projects in operation and others being considered where the CO₂ removed from natural gas reforming or partial oxidation is compressed and used for sequestration or EOR.



CO₂ Removal from Coal Gasification Plants

CO₂ removal from coal gasification derived syngas is a mature commercial process widely practiced throughout the world. A couple of coal gasification plants are noted that are currently capturing CO₂ for use in EOR.

The gasification of coal, petroleum coke and heavy oils with oxygen are in widespread commercial use for the production of chemicals such as ammonia, urea, methanol, dimethyl ether, SNG, gasoline and other transportation fuels via the Fischer Tropsch process. In these plants the produced syngas is cleaned of particulate matter and subjected to the shift reaction to produce the appropriate CO/H₂ ratio for subsequent synthesis. The sulphur in the feedstock is converted to H₂S and carbonyl sulphide (COS). Commercial shift catalysts are available for use on either sulphur containing syngas (sour gas) or on sulphur free syngas (sweet gas).

With sour gas the shift catalyst will also convert the COS to H₂S. The H₂S and CO₂ can each be removed separately or together (bulk removal) from the shifted syngas through the use of one of several commercially available AGR processes. An alternative process scheme is the removal of the sulphur species from the syngas by COS hydrolysis followed by an AGR process before conducting the shift reaction on the sweet (i.e. sulphur free) syngas.

IGCC Design Options for CO₂ Capture

There are several IGCC plants in operation in several countries but to date none of them has incorporated CO₂ capture. However several IGCC projects that include capture are being developed and there is one project, the Kemper County project in Mississippi, that is in construction.

In an IGCC plant, CO₂ capture is accomplished as previously described for gasification plants. One or two stages of water-gas shift are used on the particulate free syngas and the addition of steam may be necessary dependent on the specific gasification technology employed. This is followed by gas cooling and the separate removal of H₂S and CO₂ in two AGR absorption/stripping units arranged in series. The H₂S rich stream usually is fed to a Claus plant (sulphur recovery unit or SRU) and the CO₂ is dried and compressed for sequestration or use in EOR. Tail gas from the SRU can be recycled to the AGR inlet to improve CO₂ recovery. CO₂ capture may be added as a retrofit or included in the design of a new plant. Figure 3-2 is a block flow diagram of IGCC with CO₂ capture. It shows the typical IGCC arrangement for oxygen blown gasification processes. However the MHI and the Southern Company's TRIGTM processes are both air blown. For these air blown processes the Air Separation Unit (ASU) is essentially replaced with an additional main air compressor to augment the air extracted from the gas turbine compressor as air supplied to the gasification island.

In an IGCC plant with CO₂ capture the syngas fuel to the gas turbine is mostly comprised of hydrogen, typically diluted with nitrogen. Although the CO₂ capture process from gasification syngas is a mature commercial technology, hydrogen firing in large F Class gas turbines and the whole IGCC plant operation incorporating capture in an integrated manner has yet to be demonstrated.

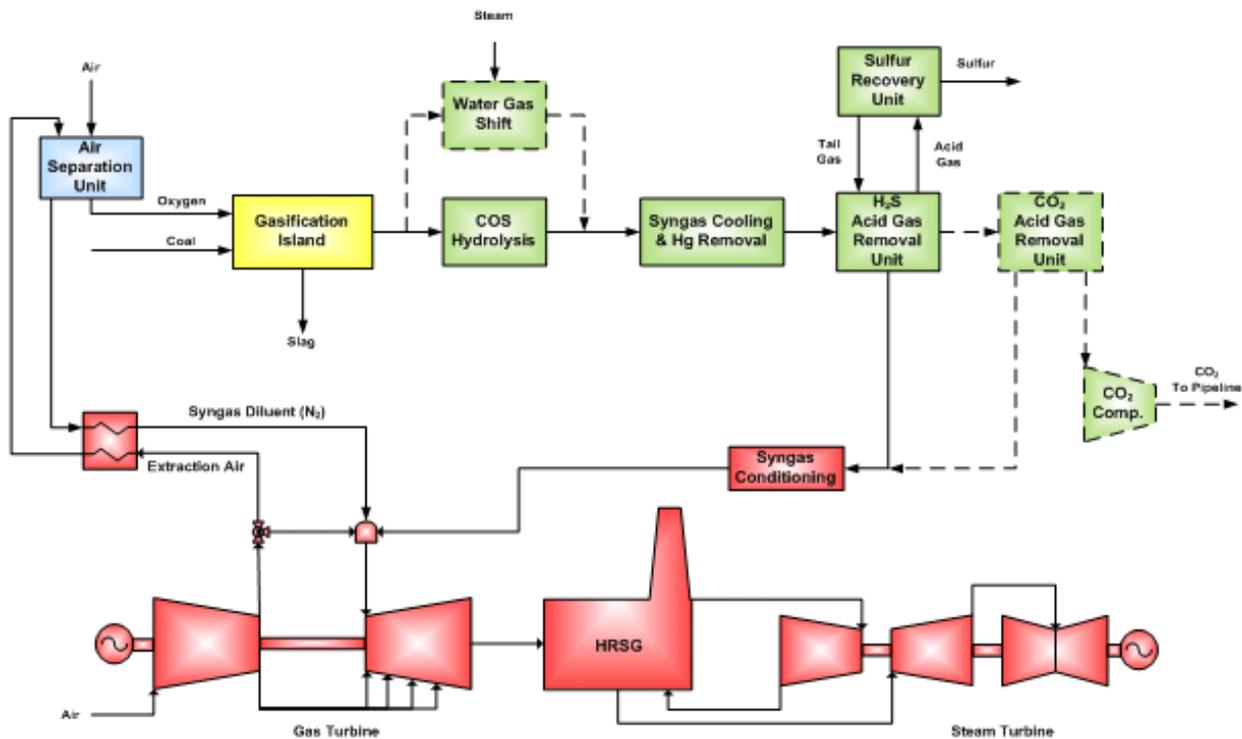


Figure 3-2
Process Flow Diagram of Generic IGCC Plant Showing Retrofit Modifications for CO₂ Capture

IGCC Retrofit Addition of Capture

There are a few IGCC plants in operation without capture however prospectively most IGCC projects will almost certainly plan to incorporate capture in the original design.

If CO₂ capture was to be added to an IGCC design that did not envisage the future addition of capture there are additional cost and performance penalties over a new built plant with capture. The addition of the shift reactor results in less syngas energy being delivered to the power block. It also results in a higher syngas flow to the AGR section so that additional absorber capacity will be needed.

Additional ASU, Gasification and gas clean-up capacity will be needed to fully load the gas turbines when Shift is added. If this oversizing is included in the initial IGCC investment this version of ‘capture ready’ would then permit full gas turbine output with hydrogen when capture is added.

Addition of sour shift increases gas flow to the AGR by 45-60% (particularly for the dry coal fed gasifiers with high CO content). The AGR would be unable to take the extra flow unless there was pre-investment oversizing. It may therefore be necessary to add a parallel absorber or replace the entire AGR plant (with a new two column absorption system) if capture is to be added to an existing IGCC designed without capture.

Alternatively the original AGR (focused on H₂S Removal) could be retained and a Sweet shift added after the AGR with a simpler bulk CO₂ removal AGR (ADIP, MDEA, Selexol) added after shift. This would minimize intrusion into existing plant. This trade off of Sour versus Sweet Shift needs to be examined and may differ among the different gasification Technologies. Sweet shift may incur additional efficiency and output penalties. Quench type gasifiers would probably favour the use of sour Shift.



Pre-Combustion Capture – Current Status and Technology Providers

TRL of Current IGCC Designs with Capture

There are several commercial sized IGCC projects with capture in and one (Kemper County) under construction. However, the designs of IGCC plants incorporating capture using current capture technology incur high energy losses of 7-8% points through the addition of capture. The energy losses occur in many parts of the IGCC flow scheme.

For an IGCC plant with capture based on current technology, the TRL of the major components of the ASU, gasification, gas cooling, shift, sulphur removal and CO₂ capture are all at TRL 9.

TRL of Pre-Combustion Capture in other Applications

The capture of CO₂ from natural gas processing, natural gas reforming and coal gasification is commercially practiced worldwide (i.e. TRL 9). In a few plants the captured CO₂ is being sequestered or used for EOR.

Leading Providers of IGCC Technology

The leading providers of gas turbine based power blocks for the IGCC application with capture are General Electric, Siemens and MHI. Each of these companies can also provide gasification technologies so that they are in a good position to supply overall IGCC technology packages when linked with ASU, shift and AGR technology providers.

The leading providers of the various IGCC component technologies described in this Section are listed in Table 3-1.

Table 3-1 Leading Providers of IGCC Component Technologies

Technology	Leading Provider Companies
Air Separation	Air Products, Praxair, Air Liquide, Linde
Gasification	Heavy Oil – General Electric, Shell, Lurgi,
	Fixed Bed – Lurgi/Air Liquide FBDB, Envirotherm BGL
	Fluid Bed - Southern/KBR TRIG™, Uhde - HTWinkler, SES U Gas, HRL IDGCC
	Entrained Flow - General Electric, ConocoPhillips E Gas™, ECUST, Shell, Siemens, Uhde, MHI (Mitsubishi Heavy Industries)
Shift	Haldor Topsoe, Sud Chemie, Johnson Matthey
Acid Gas Removal	Dow and BASF (MDEA), UOP (Selexol), Lurgi/Air Liquide and Linde (Rectisol), Shell (Sulfinol, ADIP).
Gas Turbines	General Electric, Siemens, MHI

Leading Current Providers of AGR Processes for CO₂ Capture

The leading suppliers of AGR processes are Dow and BASF for MDEA, UOP for Selexol, Lurgi/Air Liquide and Linde for Rectisol, Shell for Sulfinol and ADIP.

Pre-Combustion CO₂ Capture – Challenges/ Future Direction

Although the efficiency loss of 7-8 percentage points for addition of capture to IGCC is currently less than for PCC with MEA in SCPC, it is still very high. The major thrust in RD&D for IGCC designs with capture is to reduce the energy penalty. While the additional capital cost of capture equipment is not insignificant it is net power output loss that is the most significant economic detriment of capture addition.



CO₂ Capture at Warm or Hot Gas Temperature²

Current AGR processes operate at low temperatures below 40°C. Cooling the syngas to that temperature condenses water from the syngas with an accompanying loss of energy and mass. If the AGR could be accomplished at a higher temperature (e.g. at the temperature of the outlet of the shift reactor) there would be lower energy losses and more motive mass to the gas turbine.

RTI is developing a process for the removal of sulphur species from syngas at temperatures > 230°C using a zinc oxide based sorbent in a transport type reactor with oxidative regeneration of the loaded sorbent. This has been tested at small scale on a slipstream at the Eastman gasification plant in Kingsport, TN and a larger scale unit is to be installed and tested on a 50 MW equivalent slip stream at the Tampa Electric IGCC plant in Florida.

However to take full advantage of this process there must also be processes for the hot removal of trace contaminants (Cl, As, Hg etc) and CO₂. The Benfield and CataCarb processes that use a solution of Potassium Carbonate are possible candidates however the sorbent regeneration is at atmospheric pressure.

A more promising approach is the use of a high temperature membrane that could potentially separate hydrogen and CO₂ while producing each at relatively high pressure.

Membrane Separation of Hydrogen and CO₂

The Eltron high temperature metallic membrane for hydrogen transport has had some success at a small scale. Eastman Chemical has been brought on as a partner and a scale up is planned at the Eastman gasification site. This technology has the potential of incorporating the shift catalyst in its design. A preliminary EPRI evaluation of this technology, when preceded by RTI's warm gas clean-up process (using Zinc oxide), showed significant improvement in efficiency. The ability to produce both the hydrogen and CO₂ at pressure results in reduced auxiliary power demand.

Another type of membrane is being developed by MTRI (Membrane Technology Research Inc) for testing on syngas at the NCCC (National Carbon Capture Center). The US DOE is supporting both Eltron and MTRI in their membrane process development. These membrane technologies are considered to be at TRL (Technical Readiness Level) 4 to 5.

Other Processes for Separation of Hydrogen and CO₂

The use of chilled ammonia and cryogenic processes for CO₂ capture are being studied and have the potential to produce the captured CO₂ at pressure thereby reducing the auxiliary power load. An ammonium carbonate – ammonium bicarbonate (AC-ABC) process is being developed, under DOE-NETL funding, by Stanford Research Institute (SRI) for pre-combustion capture of CO₂. SRI had previously conducted some of the initial experimental work using the same AC-ABC system for post combustion CO₂ capture that formed the basis for the Alstom chilled ammonia PCC process. The pre combustion AC-ABC process is at about TRL 4-5. The use of a cryogenic process for the pre-combustion removal of CO₂ by chilling the shifted syngas stream has also been proposed but not yet tested. This is considered to be at TRL 2 to 3.

Energy Losses in IGCC with Capture and RD&D Needs³

Although there is additional capital involved, the largest component of the poor economic performance in pre-combustion capture systems is the loss of energy involved. Much of the RD&D effort is aimed at reducing the energy losses due to capture in the various process steps but one of the greatest improvements to the overall IGCC technology is the development of high firing temperature larger gas turbines of higher efficiency. This

² Evaluation of Potential Improvements in IGCC Pre-combustion CO₂ Capture. EPRI Report # 1021640. A.Bhown, N.Holt December 2010.

³ Gasification Technology Status- December 2010. Section 6 Ongoing RD&D of IGCC Improvements. EPRI Report # 101966. N.Holt. December 2010.



latter improvement will occur regardless of any requirement for CO₂ capture. The major energy loss components and the RD&D needed to reduce these losses are shown in Table 3-2:

Table 3-2 Pre Combustion Energy Losses and RD&D Needs

Pre-Combustion Capture Energy Loss Component	Comments/RD&D Needed	R&D in Progress	TRL of RD&D
The ASU has high auxiliary power demand for the main air compressor, oxygen and nitrogen compression	Development of ASU process with lower power demand.	Air Products ITM 1 mt/d moving to 100 mt/d oxygen	6 moving to 7
Reduction in syngas chemical heating value from the endothermic shift reaction	This loss is inevitable with the shift reaction		
Addition of steam to the shift reducing steam turbine output	Improved shift catalysts that function at a lower steam/CO ratio	All shift vendors	Various 6-8
Energy losses from cooling the shifted syngas to the temperatures required for the current AGR processes	Warm gas clean up for sulphur species and trace element removal	50 MW RTI test at Tampa	7 moving to 8
Compression energy to raise the pressure of the CO ₂ recovered from AGR processes	Membranes to produce both CO ₂ and Hydrogen at high pressure	Eltron test at Eastman	4 moving to 5
Limits on air extraction from gas turbines increase the auxiliary load for the main air compressor supplying air to the ASU	Gas turbine compressor designs that permit air extraction when firing hydrogen	All gas turbine vendors. DOE support of GE and Siemens. Japan for MHI.	7
Compression of the CO ₂ to pipeline pressure	Produce CO ₂ at higher pressure. Improved compression concepts. Improved heat recovery	RamGen	5
Reduced firing temperature of hydrogen fired gas turbines	Higher firing temperature larger gas turbines for Hydrogen provide higher efficiency and economies of scale. Need larger gasifiers to provide the hydrogen fuel for the larger gas turbines	All gas turbine vendors. DOE support for GE & Siemens. Japan for MHI	5



Potential Improvements to Supporting Technologies

ASU

The Ion Transport Membrane (ITM) for low cost oxygen production currently being developed by Air Products with major DOE support promises reduced auxiliary power usage⁴. The ceramic membrane exclusively allows only oxygen ions to migrate through the solid. The process takes place at very high temperatures of ~1,000°C (~1,832°F) and moderate pressure across the membrane is required. The current test unit is 1 mt/d and plans are moving forward for a 100 mt/d unit to be operational in 2012. The integration of this technology into IGCC or Oxy combustion plants is a significant challenge.

Shift

The shift reaction can be conducted on the sour syngas before sulphur removal ('sour shift') or after sulphur removal ('sweet shift'). Industrial catalysts are available for both types. Most IGCC + CCS designs use the sour shift approach. The major shift catalyst suppliers (SudChemie, Haldor Topsoe, and Johnson Matthey) and Shell have active programs to improve the performance of shift catalyst to operate at lower steam/CO ratios without carbon lay down or methanation issues. This is particularly important for dry coal fed gasifiers with their high CO content in the raw syngas. In an IGCC + CCS plant design based on dry fed gasifiers the steam often has to be taken from the steam cycle to meet the shift catalyst requirements thereby reducing the steam turbine output and adversely affecting the overall performance and plant efficiency.

Gas Turbines for Hydrogen

F class gas turbines have not yet been demonstrated commercially with hydrogen fuel however by reducing the firing temperature (which reduces power output and efficiency) GE, Siemens and MHI do offer F class gas turbines with commercial guarantees.

Since 2005 GE and Siemens have been developing advanced gas turbine technologies under a joint DOE sponsored initiative that is aimed at reducing syngas turbine emissions and improving efficiency of IGCC applications incorporating CCS.

The main elements of the programs are higher firing temperatures, advanced sealing and cooling, and advanced materials and coatings to allow higher temperature operation with high hydrogen content syngas. Another goal is to achieve low NOx emissions with lower use of diluent nitrogen.

Siemens has estimated that 8-9 per cent efficiency points are lost to IGCC plant designs when CO₂ Capture is included but that 5% efficiency can be gained back by the use of Advanced high hydrogen fired gas turbine technology. Siemens is currently offering their 8000 H gas turbines for natural gas firing and under the DOE joint program plans to adapt this design to the IGCC application.

MHI has announced plans for J type gas turbines with a firing temperature of 1600°C (100°C higher than the G turbines) and a power output about 1.2 times that of G turbines. The target availability for the J turbine on natural gas is 2011 with the first operation in 2013. The higher efficiency and greater output will provide marked improvements in IGCC economics. At the 2010 Gasification Technologies Conference, MHI outlined a future trajectory of advanced gas turbines for IGCC with the J class availability about 2017, further 1700°C gas turbines beyond 2020 and later integration with fuel cells.

The Future of Pre-Combustion Capture Technology

The next key event for the advance of pre-combustion capture technology will be the integrated operation of the first IGCC plant with capture at the Kemper County IGCC plant in Mississippi in 2014. This will hopefully be followed by some of the other IGCC projects under development.

Additional projects recovering CO₂ from natural gas processing (e.g. Gorgon) and possibly from natural gas reforming will also enter operation in the next few years.

⁴ Scale up and Integration of Ion Transfer Membrane Oxygen Production Technology. EPRI # 1018956



There is a very active program underway on most of the RD&D elements identified in Table 3-1 with funding from the DOE and the technology suppliers. EPRI⁵ and DOE have identified a roadmap of IGCC technology developments that can potentially improve the IGCC efficiency to a level that matches or exceeds that of the current IGCC technology without capture. This is illustrated in Figure 3-3. The addition of capture with current technology reduces the efficiency by about 8 percentage points. The higher firing temperature G class gas turbines increase it by about 2.5 per cent. The use of ITM for the ASU can add another 1% to efficiency. The use of feeding the coal to the gasifier as a coal in liquid CO₂ slurry is projected to improve efficiency by about 2%. Incorporation of the RTI and Eltron advanced capture processes, together with the other advances is projected to recover the 8% efficiency loss with the current capture technologies.

With IGCC there are multiple pathways of improvements using different gasification technologies which may find particular application more favourably in certain climate conditions, locations and coal types. Figure 3-3 indicates an improvement from the use of a coal in liquid CO₂ slurry that would improve the efficiency of slurry fed gasifiers particularly for low rank coals. For dry coal fed gasifiers the development of a coal pump could produce similar efficiency gains.

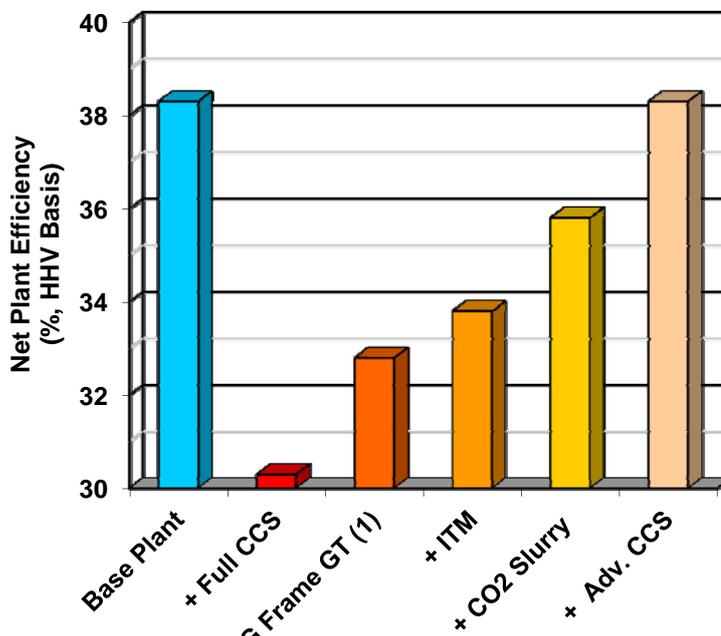


Figure 3-3 IGCC Developments to recover Energy Losses from CO₂ Capture

⁵ The Future of IGCC Technology – CCPC-EPRI IGCC Roadmap Results. R. Schoff (EPRI). IEA CCT 2011. Zaragoza, Spain May 10, 2011



ACRONYMS AND SYMBOLS

AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid gas removal
AQCS	Air Quality Control System
ASU	Air Separation Unit
B&W	Babcock & Wilcox
Bara	Bars absolute
Barg	Bars gauge
BFW	Boiler feedwater
BP	British Petroleum
Btu	British thermal unit
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCPI	Clean Coal Power Initiative
CCS	CO ₂ capture and Storage (or Sequestration)
CCT	Clean Coal Technology
CF	Capacity Factor
CFB	Circulating fluidized bed
CHP	Combined Heat and Power
CO ₂	Carbon dioxide
COE	Cost of electricity
COP	ConocoPhillips
CT	Combustion Turbine
DOE	U. S. Department of Energy
DOE NETL	Department of Energy National Energy Technology Laboratory
ECUST	East China University of Science and Technology
EEPR	European Energy Programme for Recovery
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
FBC	Fluidized-bed combustion/combustor
FEED	Front End Engineering Design
FGD	Flue gas desulphurization
FOAK	First of a kind
F-T	Fischer Tropsch
ft ³	Cubic feet
FW	Foster Wheeler
FWI	Foster Wheeler Italiana
GHG	Greenhouse Gas
GI	Gasification Island
GJ	Gigajoule
gpm	Gallons per minute (US)
GT	Gas Turbine
H ₂ S	Hydrogen sulfide
HgA	Mercury absolute
HHV	Higher heating value
HRSG	Heat recovery steam generator
HP	High pressure
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate pressure
IPP	Independent power producer
kJ	Kilojoules
KBR	Kellogg, Brown & Root
LCA	Life Cycle Analysis
LCOE	Levelised Cost of Electricity



LHV	Lower heating value
LP	Low pressure
LSTK	Lump Sum Turnkey
mt	Metric ton
MDEA	MethylDiethanolamine
MMBtu	Million Btu
MPa	Mega Pascal
MTG	Methanol to Gasoline
MTO	Methanol to Olefins
NCCC	National Carbon Capture Center
NDRC	National Development and Reform Commission (China)
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NH ₃	Ammonia
Nm ³	Normal cubic meters
NO _x	Nitrogen oxides
NSPS	New Source Performance Standards
OCGT	Open Cycle Gas turbine
O&M	Operation and maintenance
PC	Pulverized Coal
PCC	Post Combustion Capture
ppmv	parts per million by volume
PRB	Powder River Basin (Coal)
PSDF	Power System Development Facility
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
R&D	Research & Development
RD&D	Research, Development and Demonstration
RQ	Radiant Quench (GE)
RTI	Research Triangle Institute
RWE	Rheinische Westphalien Electricidadeswerke
SCFD	Standard Cubic Feet per day
SNG	Substitute Natural Gas
SCPC	Supercritical Pulverized Coal
SCR	Selective catalytic reduction
SO ₂	Sulphur dioxide
SRU	Sulphur Recovery Unit
st	Short ton (2000 pounds)
stpd	Short tons per day
TCR	Total Capital Requirement
TFC	Total Field Cost
TPC	Total Plant Cost
USC	Ultra Supercritical
US EPA	US Environmental Protection Agency
WGCU	Warm gas clean up