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**ECONOMIC DRIVERS TO IMPLEMENT CARBON CAPTURE AND STORAGE (CCS) PROJECTS
FOR GREENHOUSE GAS MITIGATION FROM NEW POWER PLANTS**

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Abstract

The paper addresses economic drivers (and lack of drivers). It compares 3 post combustion carbon capture processes: Alstom's CAP, MHI's KM CDR and Fluor Econamine FG. The two pre-carbon capture processes compared are: SELEXOL™ 2-Stage and The New Process.

All technologies are summarized together on a common net efficiency basis, alongside their respective non-carbon capture benchmark. The efficiencies are based on coal utilization, but a side discussion suggests that the results are also applicable to natural gas based fuel, to generate power.

A new energy efficient process for CCS (carbon capture and storage) is offered in a pre-combustion process. The new pre-combustion carbon capture process (patent pending) operates at high pressure. The bulk of the dry, sulfur free CO₂ is first condensed at high pressure and low temperature above the CO₂ freezing point. The residual, uncondensed CO₂ is then removed via either a traditional solvent process or via adsorption by a PSA. Finally, all the captured (liquefied) CO₂ is purified to remove CO and other light-end gases prior to the liquid CO₂ being pumped to above its critical pressure for its ultimate disposal.

The study compares the new carbon capture (CC) process against a benchmark. The benchmark comparison process is a state-of-the-art physical process, followed by CO₂ compression to supercritical pressure.

Significant energy savings (about 50%) are demonstrated with the combination of the selective H₂S removal process, followed by the new process.

The New Process is also applicable in CC, from synthesis gas derived from natural gas and shale "fracking" gas.

Economic Drivers to Implement Carbon Capture and Storage (CCS) Projects

for Greenhouse Gas Mitigation in New Power Plants

Background

There are Acid Gas Removal (AGR) technologies which, for the most part, are used to make a valuable gas stream more valuable. For example natural gas (NG) refinery fuel gas (RFG) and synthesis gas “Syn Gas” are valuable gases which may contain CO₂ to some extent. Examples of non-valuable gasses, containing CO₂ are CO₂ discharge from a vent, or flue gas from a combustion process which contains CO₂. Traditional AGR processes were designed to make a valuable gas more valuable by removing the CO₂, the inert component in the valuable gas.

New Technology is Available

New technology has been developed to capture CO₂ from a non-valuable gas. There are several examples of the new technology. In the case of post combustion carbon capture (CC), the most developed technology examples are:

- Fluor’s Econamine FG
- MHI’s (Mitsubishi Heavy Industries) KM CDR
- Alstom’s CAP

The Fluor process uses MEA (a primary amine) with proprietary additives that help minimize corrosion. MHI’s process uses a proprietary sterically hindered amine. While Alstom’s CAP process uses chilled ammonia as the CC solvent.

In the case of pre-combustion CC, the best known processes are:

- UOP’s SELEXOL™ 2- Stage Process (Generic solvent is DEPG)
- Lurgi and Linde’s RECTISOL® (Generic solvent is methanol)

The third category is classified as oxy-fuel combustion, in which oxygen or oxygen enriched air is used instead to combust the fuel. The perceived advantage is the elimination (partially or fully) of nitrogen from the products of combustion. The combustion products therefore contain mostly CO₂ and water vapor, in which the CO₂ is most easily isolated by cooling the products of combustion, condensing the vast majority of the water.

Traditional vs New CC Technology

The traditional technology was designed to meet an economic need. The impact of removing the CO₂ was (and still is) to improve the value of the gas and therefore add value to the enterprise. The economic improvement justifies the cost of implementing the capture of CO₂.

The new technology that has been developed to date does not add value (by removing the CO₂) from the non-valuable gas stream, and does not (under current regulations) add value to the enterprise.

Without an economic incentive, new CCS projects will not be implemented.

The Economic Barriers to Implement CCS

There are three main barriers to implement a CCS project:

- The CO₂ captured has low or no value.

- The enterprise needs to invest in a facility designed for CCS in which there is both high CAPEX and high OPEX
- There is a high lawsuit risk for the enterprise responsible for storing the CO₂

In the absence of these barriers, CCS projects used to produce CO₂ for enhanced oil recovery (EOR) may prove to be economically viable in certain geographically favored locations. However, these locations are generally hard to find.

Removing these economic barriers will require government intervention.

Without government intervention there is no economic incentive and new CCS projects will not be implemented.

Government Regulations/Incentives

Possible government interventions to make CCS economically feasible (or desirable) can take several forms. Four forms are identified as likely, while other less likely forms have been postulated. The possible government interventions include:

1. Artificial price support for the CO₂ captured. This can be enacted by either offering CO₂ tax credits on the CO₂ captured and stored or on CO₂ tax penalties on the emitted CO₂.
2. Government subsidy can be provided to the project developer on an agreed floor price of the captured and stored (or sequestered) CO₂ stream.
3. A subsidy (or grant) can be provided to the developer to offset the high CAPEX and or OPEX of the CCS project on a case-by-case basis.
4. Government regulations can be enacted to set limits of liability for the sequestration of CO₂ into geological formations.

Considerations for Developing New Power Producing Facilities

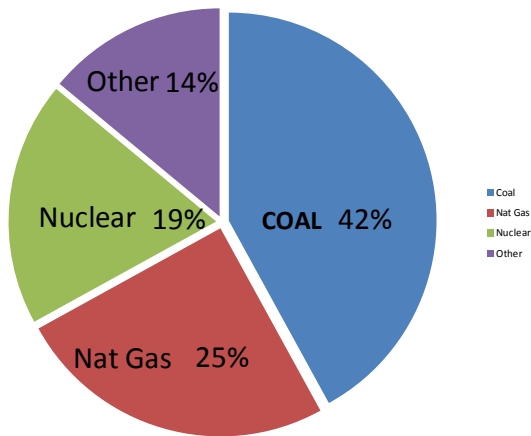
In the absence of current regulations, new power projects need not invest in CCS. However, it may be prudent to pre-invest in a plan to retrofit power plants in the event of government enactment of one or more of the 4 above regulations, providing a “capture ready” design.

Considerations for Capture Ready Designs for New Power Plants, Prior to Future CCS Regulations

A new power production facility needs to consider several factors. For example, fuel choices include:

1. Coal/ and or Coke
2. Natural Gas
3. Liquid Petroleum Products

Currently the US Power producers are using the fuel in the following proportions:



Another consideration for a new power producing facility is the amount of CO₂ emission from the different fuel choices. For a given amount of gross power produced, the amount of emitted CO₂ is greatest when burning coal.

	<u>Fuel</u>	<u>LBS of CO₂ Emitted /kWh</u>
1)	Coal	2.0 to 2.1
2)	Nat Gas	1.12
3)	Oil Based Fuel	1.6

New Disruptive Technology

New “disruptive technology” has changed the economics, prior to the implementation of this new technology. Shale gas, horizontal drilling and “Fracturing” techniques (“Frac Gas”) have resulted in a steady increase in natural gas supply. This newfound natural gas has been produced in ever-increasing volumes over the last 5 years, resulting in progressively lower natural gas prices and a decoupling from the oil price. (Previously oil and natural gas commodity prices would typically rise and fall together, however, since the new gas supplies have become available, there is no longer as strong a correlation between oil and natural gas prices).

As more Frac Gas (natural gas) comes on-line and continues to make inroads, the fuel of choice will likely switch towards more Nat Gas, rather than coal. The power industry is in a “wait-and-see” mode to see if the Frac Gas is a sustainable (and reliable) source of supply.

We may have seen the lowest natural gas selling price in April 2012 and there is speculation that the price will rise as more power producers switch to natural gas and the cost of producing the natural gas exceeds the current selling price. Eventually, the market will find a new price to balance the supply and the demand.

Summarizing the Options Available for Developing a New Power Producing Facility

Realistically the major economically driven considerations are:

- Nat Gas versus other fuels

- Suitability of a retrofit process for future CCS implementation in a carbon-capture ready plant

Nat Gas versus Other Fuels for New Power Producing Facilities

As we have discussed, natural gas has become a relatively low cost fuel, due to new “fracking” technology. The CAPEX of a natural gas fueled power plant (using combined cycle) is considerably lower than any alternative fuel option now, and for the foreseeable future. The mass of CO₂ emissions per kWh is half that of coal. The alternative options of nuclear, hydro-electric and renewable energy will provide an even lower mass of CO₂ emission per kWh (zero), but the CAPEX for these options are significantly higher compared to natural gas. At this present time, it is difficult to justify any new power plant built around a fuel other than natural gas.

Suitability of Different Retrofit Processes for Future CCS Implementation

Initially it was established that Oxy-Fuel combustion plants do not lend themselves to a retrofit application. The difficulties of retrofitting an oxy-burn fuel on a modern designed coal or gas fired power plant are too costly. However, most recently there was a report of new CFB (Circulating Fluidized Bed) technology that can either operate using coal with traditional air combustion, or can use oxygen mixed with recycled flue gas if and when the new government regulations kick-in. CFB technology is not suitable for natural gas fuel power production.

Both post-combustion CCS processes and pre-combustion CCS processes are candidates for power plant retrofits and both remain in contention at this time.

Lowest Life-Cycle Costs for Retrofit CCS Power Producing Projects

The cost of CCS amounts to more than just the cost of the CO₂ capture itself. Major additional costs are associated with delivering the captured CO₂ in a relatively pure state and at a very high pressure. This is because of the requirement to transport the CO₂ (typically by pipeline) safely and economically. The CO₂ enters the transmission pipeline at high pressure (typically around 2200 psi) in order that the CO₂ will flow with minimum recompression to its destination delivery site. The delivery site could be one of several possibilities where the CO₂ is:

- Sold for enhanced oil recovery (EOR)
- Stored into a depleted oil or gas field
- Stored in a saline aquifer
- Stored in some other geological formation where the CO₂ will be forever sequestered (entombed) and not allowed to escape into the atmosphere.

When the captured CO₂ is used for EOR, the CO₂ will need to be processed to promote miscibility with the oil in the formation. A typical specification limit for the impurity of the co-absorbed hydrocarbons is less than 5%; the CO₂ needs to be at least 95% pure. For disposition of CO₂ in any of the above options, pipeline corrosion is a serious issue if the CO₂ is wet, and contains O₂. Also, in disposition of the CO₂ to any of the above options, the safety of transporting CO₂ will limit the amount of H₂S and CO permitted to remain in the CO₂ product stream. The risk is if there is a pipe failure and the CO₂ is released, the H₂S or CO could cause injury or fatality.

The contaminating product that is typically found in a post combustion process is water vapor and O₂. The CO₂ is typically dried by a recirculating tri-ethylene glycol dehydration package, inserted between one of the multiple compression stages. Typically there are no for hydrocarbons, H₂S or CO in the post-combustion derived CO₂. For the pre-combustion process, which typically uses a physical absorbent operating at high pressure, the product can also contain

the contaminants of hydrocarbons, as well as H₂S and CO. Usually there is no O₂, and the gas can be bone dry or will need to be dried depending on the process chosen. The cost of removing any of the contaminants from the CO₂ to meet the required CO₂ specification limits is part of the CCS project.

Finally, the cost of compressing the CO₂ from approximately atmospheric pressure to pipeline inlet pressure at about 2200 psi is borne by the CCS project. Typical CO₂ compression requires 5 or more stages with inter-stage cooling between stages.

In summary, the cost of CCS includes the total cost of the CO₂ capture, its purification and its compression to supercritical pressure, typically about 2200 psi. This pressure level is an industry standard used as a means for comparing the various potential candidate process at a common battery limit condition.

Candidate CCS Processes Compared on an Overall Efficiency Basis

A few representative processes are selected to compare the trend of efficiency of a project following the retrofit of a CCS process. This is helpful in the decision making process for selecting the type of new power producing technology and its fuel in anticipation for a future retrofit add-on project.

One criterion is to look at the conversion efficiency of fuel to useful (saleable) power. Saleable power excludes the parasitic power consumption need to capture the CO₂ since that power is no longer available to contribute to the revenue of the enterprise. The fuel conversion efficiency criterion is a useful measure of overall economic comparison, since these utility projects are based on a real life of typically over 30 years. The lifetime used for depreciation is not the preferred metric used for comparing the IRR or NPV of the CCS project. The actual life (longer than the depreciation life) of the CCS project is most important for the enterprise.

A quick analysis will show that a modest improvement of fuel conversion efficiency (as defined above) will result in a significant impact on the lifetime IRR or NPV, while some fairly large differentials in CAPEX, while important, have a comparatively lower impact on IRR and NPV. The Key Performance Indicator (KPI) is the conversion efficiency of fuel to saleable power since this correlates to IRR, and NPV and will at the least give the ranking of technologies to provide Levelized Cost of Energy (LCE)

When looking at the efficiency comparisons, the most efficient processes will be the process without the need for CCS. This is the current situation. After government regulations kick-in, there will inevitably be a drop in plant overall conversion efficiency to power the CCS retrofit project. This drop in efficiency results in the lost opportunity to sell the power required to meet the power needs of the retrofit project. So the goal of the comparison is to see which CC process has the smallest parasitic power consumption.

Prior to making the final decision on the power producing (plus retrofit) technology, it will be required to compare the life cycle analyses, including the respective CAPEX and OPEX costs of the competing retrofit processes. This is required to confirm the initial assumptions of the KPI.

A total of five competing candidate retrofit processes are presented as representative of viable processes available in the marketplace today, with acceptable “bankable” risks. Three are based on post-combustion carbon capture, and two are based on pre-combustion carbon capture. The technologies of each process are summarized and available in several previous publications. For full details of these competing technologies, please review the information found at website: www.ArnoldKeller.com.

The previous studies for comparison of the processes were made using coal as the fuel. However, if natural gas is the fuel of choice, the process rankings will be maintained, but the degree of fuel conversion efficiency differences will likely

be larger, compared to the differences shown for the coal comparison cases. A new study would be required to compare the same selected processes using a natural gas feed fuel source.

The three post-combustion Processes compared are:

- Fluor's Econamine FG
- MHI's KM CDR
- Alstom's CAP

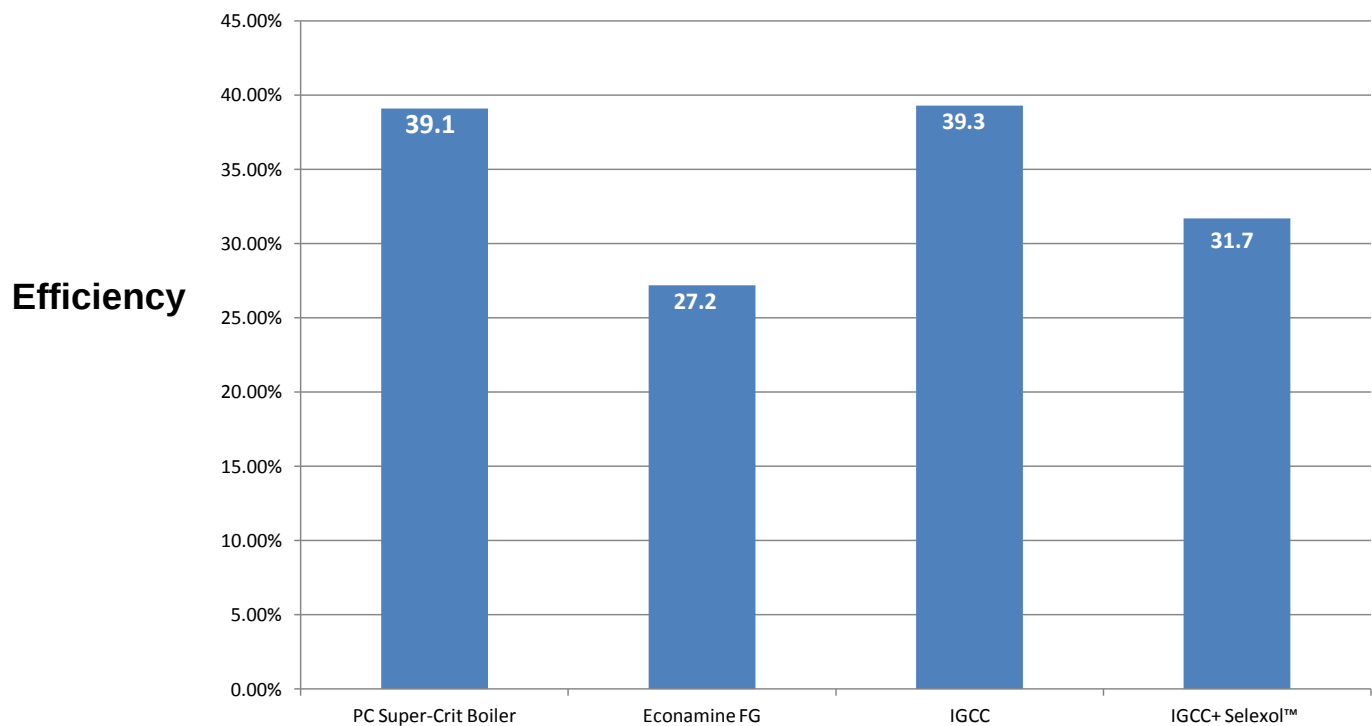
The two pre-combustion Processes compared

- SELEXOL™ 2-Stage Process (Generic solvent is DEPG)
- New Process (Patent Pending) details available at www.ArnoldKeller.com

The initial basis of this study leveraged its results from the benchmark DOE/NETL Cost and Performance Baseline for Fossil Energy Plants. PC Super critical refers to "Pulverized Coal" fired boilers operating at the supercritical pressure of steam. IGCC is Integrated Gasification Combined Cycle.

Results

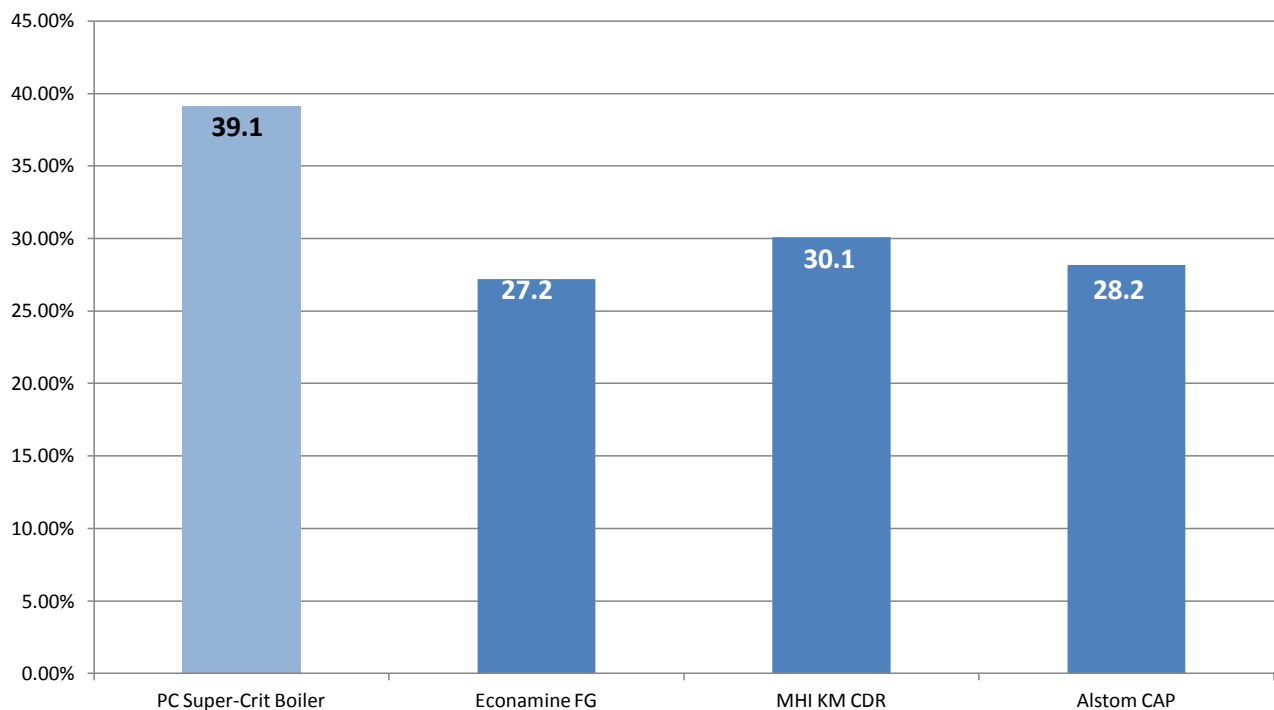
DOE/NETL Comparative Technology Study 2007



Four of the 12 DOE/NETL studies are compared based on efficiency.

It is noted that there are similar efficiency results of super-critical PC technology, compared to almost identical results of IGCC without carbon capture (CC). However, after requiring CC at 90% of the CO₂ discharged, the result shows a smaller power penalty for the IGCC case, plus retrofit plant, compared to the super-critical PC technology, plus retrofit plant.

Overall Efficiency Impact on CC on PC Fired Power Production with different Technologies



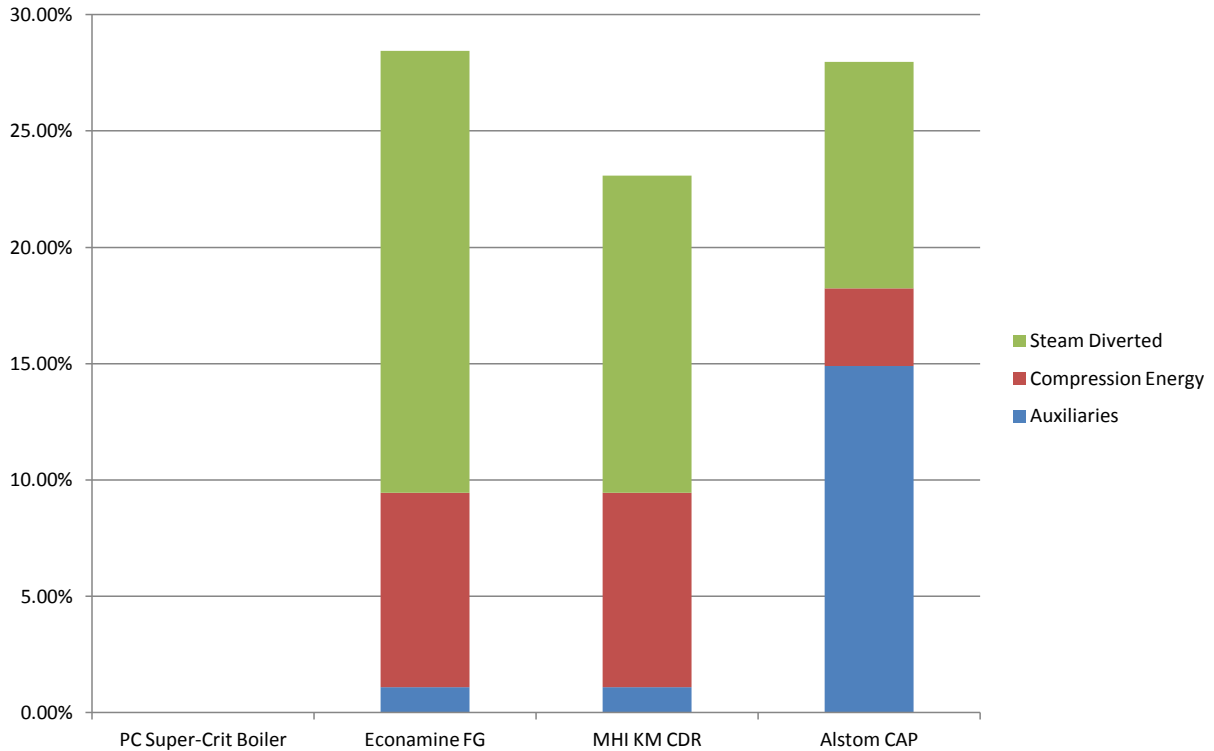
This shows the net effect of post combustion CC on a PC supercritical technology, using the different solvents. Solvents with the least requirement of regeneration heat are most advantageous.

The least amount of heat needed to regenerate the CO₂ is from the Alstom CAP process. It is lower than both Econamine FG, and the KM CDR process, so the first inclination is to assume the Alstom's CAP process would prove to be the best.

Furthermore, Alstom's CAP process is designed to discharge its CO₂ at a pressure of roughly 300 psig (saving roughly 2 stages of compression).

Something else must be going on in the CAP process for it to be less effective than the KM CDR process. Further analysis is required to understand the counter intuitive result.

Post-Combustion CC Parasitic Loss Breakdown

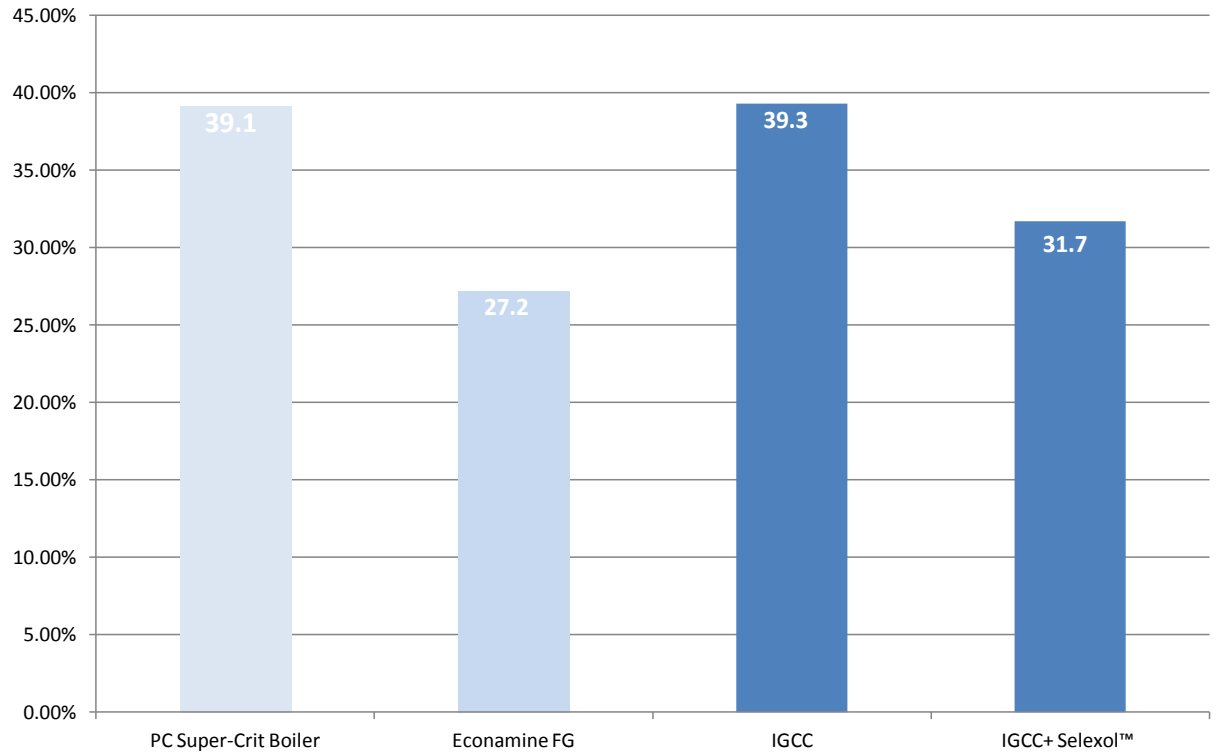


This chart compares the breakdown of the parasitic power loss from each of the post combustion CC processes. In each graph, the green section represents steam energy consumed in regenerating the solvent and is shown on top. The red section is the compression energy (shown in the middle of the bar). While the blue section on the bottom of the bar is the sum of auxiliary power loads, such as: pumps, blowers, refrigeration units, etc.

Comparing the Alston CAP process with the other two processes shows that the regeneration steam and the compression energy is indeed the lowest. However, the larger auxiliary loads negate the other benefits of this process. The auxiliary load is site specific due to climate temperature variations. A particularly cold climate will benefit the overall efficiency of the CAP process with lower auxiliary loads, and the warmer climates will prove to be more of a disadvantage to the CAP (compared to the alternatives, as shown above).

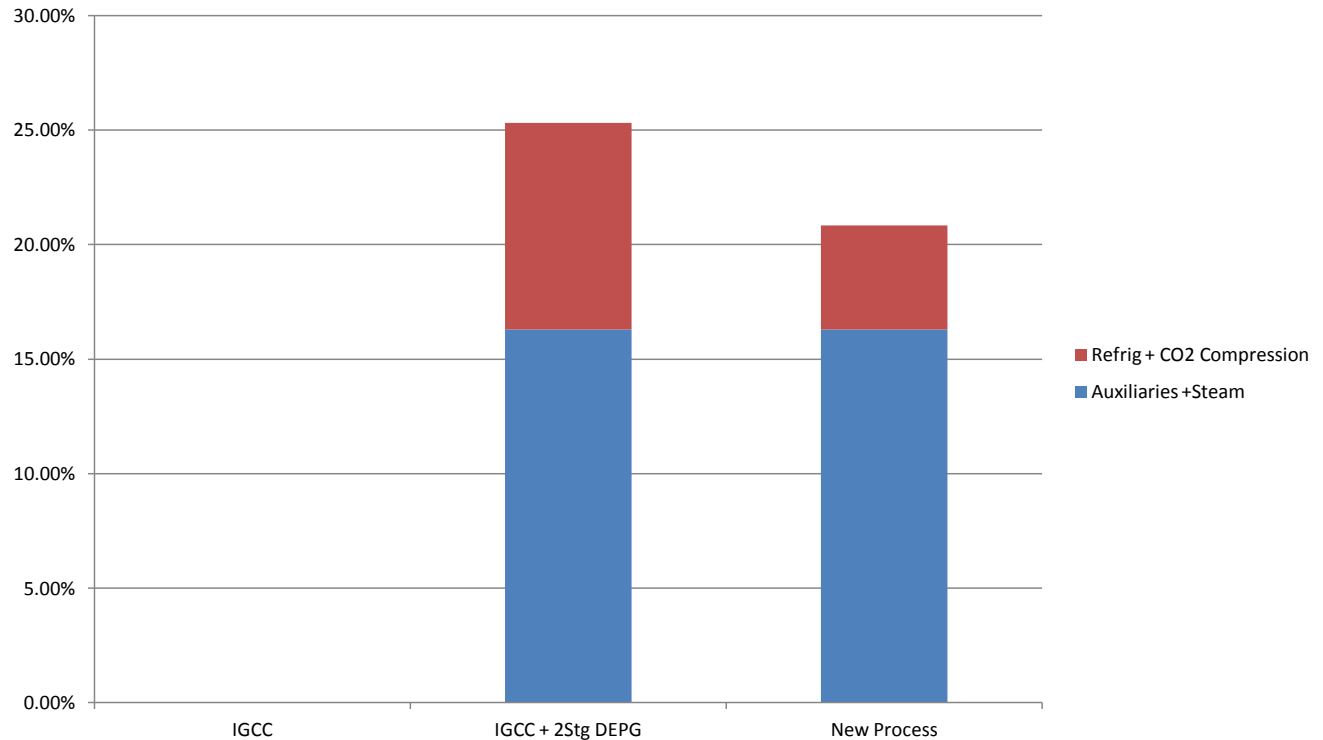
DOE/NETL

Comparative Efficiency Study 2007



Review a previous graph in order to compare the pre-combustion technology with the New Pre-combustion CC processes.

Pre-Combustion CC Parasitic Loss Breakdown

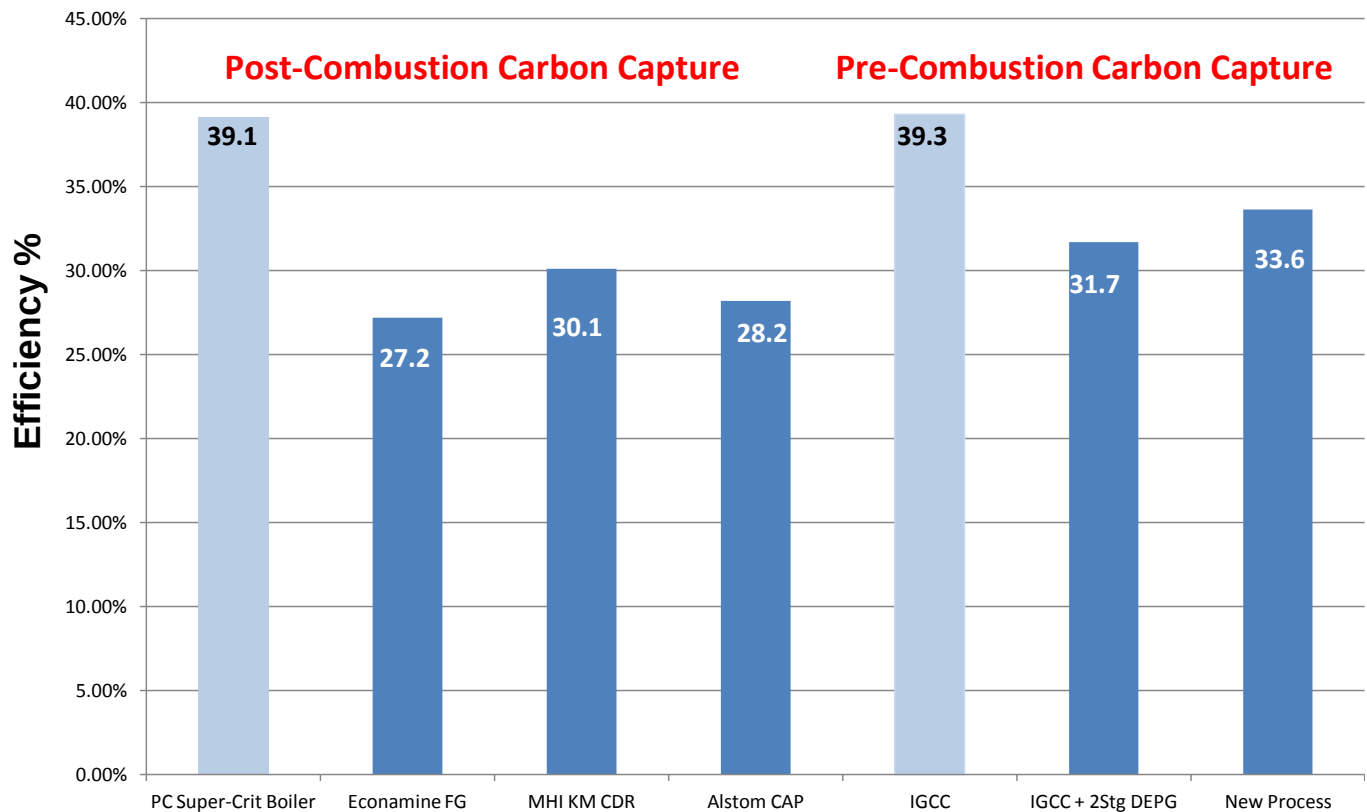


This shows the comparison of the New Pre-Combustion Process (following IGCC) against the conventional state-of-the-art process benchmarked in the DOE/NETL 2007 study (IGCC + 2 Stage DEPG).

Power consumption in the New Process is about 50% lower than the conventional state-of-the-art process.

Other methods can be used to minimize the additional steam needed for the CO-Shift reaction.

Comparative Summary



This shows the comparison of all the processes in a single chart.

For post combustion CC the most efficient process is KM CDR at 30.1 %, the pre-combustion conventional 2-stage DEPG process is 31.7 %, while the new pre-combustion process is 33.6%, the most efficient process in this comparison.

Financial Implication

The financial benefit is quite impressive, of a retrofit carbon capture process in which there is a modest benefit of 1.9% fuel conversion efficiency over its closest rival.

Assume a coal fuel consumption of 1400 MWh fuel equivalent is used in a standardized 550 MW plant.

Prior to a retrofit plant, power is produced at 39.3% efficiency. This will generate 550.2 MWh of power for sales.

An IGCC with a 2-stage DEPG pre-combustion process produces net power with a 31.7% efficiency generates 443.8 MWh. Comparing this to an IGCC with The New Process in pre-combustion with a 33.6% efficiency, generating 470.4 MWh

1st year incremental revenue between alternative retrofit process = $(470.4 - 443.8) \times 8000 \text{ hrs/yr} \times 90 \text{ \$/MWh} = \$19.7$ million/yr

The New Process

This New Process significantly reduces the life cycle cost (compared to the other current state-of-the-art processes) for H₂S removal and Carbon Capture and Sequestration (CCS) from a synthesis gas following coal/coke gasification.

One of the features of the New Process is that it only requires equipment which is available from multiple vendors in the marketplace today, and does not require any new R&D effort to develop new technology, such as new solvents, catalysts, or techniques.

The new technology is specifically designed to be “bank fundable” since the New Process uses elements of existing technology where each element is independently proven in commercial applications. The patent claims are based on the unique sequence of the conventional technology which allows for extensive heat integration, which in turn results in the much lower power consumption, compared to state of the art technologies.

This summary is made within the context of extracting acid gas from synthetic gas generated by the gasifier in an IGCC project, which includes full CO-Shift reaction and pre-combustion CCS. The objective is to capture the CO₂ cost effectively and to purify it, so that it can be transported safely by pipeline in a super-critical state.

The two most commonly employed processes used by industry to extract H₂S and capture CO₂ for sequestration from a syngas stream are Selexol™ and Rectisol®.

The Selexol™ process is based on a physical solvent, a blend of dimethyl ethers of polyethylene glycol (DEPG). This process operates at relatively warm temperatures and selectively extracts H₂S, but less optimally captures the CO₂.

The Rectisol® process is also based on a physical solvent. The Rectisol® solvent is methanol which operates at relatively colder temperatures than DEPG. The methanol solvent can more economically capture the high concentration of CO₂ in the synthesis gas compared to DEPG, but unfortunately, methanol is not as economical as DEPG at selectively absorbing H₂S in a stream containing both H₂S and CO₂, when both occur simultaneously.

Rather than applying only one of these technologies, either DEPG or methanol to simultaneously remove the H₂S and capture the CO₂, the New Process utilizes the best attributes of each of these commercially available “open art” solvents sequentially as part of a 5 stage process, as follows:

1. H₂S is removed selectively from the synthetic gas, leaving the gasification technical battery limits by a DEPG process prior to the CO-Shift reaction. The H₂S removed is sent to a Claus unit for further processing
2. The synthesis gas is CO shifted and the resultant synthesis gas, comprised of mostly H₂ and CO₂, is cooled and dewatered.

3. The high pressure, sulfur free, fully dried synthesis gas is subjected to bulk CO₂ removal by way of condensation of the CO₂ by chilling the synthesis gas. The chilling is capable of economically removing between 30% to 70% or more of the CO₂ (depending on the partial pressure of CO₂ in the synthesis gas stream). The chilling is accomplished by application of progressively colder refrigeration, while being careful to avoid freezing the liquefied CO₂ at temperatures colder than -69 deg F in the final chiller.
4. Residual CO₂ in the synthetic gas (not removed by the bulk CO₂ removal stage 3) is subsequently removed. This is achieved by absorption into a refrigerated methanol stream which is then heated at pressure and then flashed within the range of 200 to 300 psia. The CO₂ flashed stream is compressed and cooled until it condenses. This CO₂ condensate is then added to the CO₂ stream extracted from the bulk removal stage 3.
5. The combined CO₂ liquid product stream is then purified by distillation.

This 5th stage is needed because there are limitations in the granting of permits with 1,000 ppm CO specifications for new CO₂ discharge permits. Regulatory authorities increasingly have needed to tighten rules for permitting discharge streams of CO₂ to limit the CO specification at 200 ppm. This can occur when a municipality has already attained the maximum level of CO that can be discharged in their jurisdiction, due to granting prior permits. This results in the late comer having to meet the more stringent CO specification.

The final 5th stage in the New Process will reduce the CO content in the CO₂ to less than 200 ppm, and will recover small amounts of hydrogen, nitrogen and methane by distillation purification.

It is then possible to pump the purified CO₂ bottoms product to about 2,200 psi for custody transfer in the high pressure pipeline.

. Technical information on the New Process can be found at www.ArnoldKeller.com