

**PWR2006-88112**

## TURNING NGCC INTO IGCC: CYCLE RETROFITTING ISSUES

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### ABSTRACT

The increase in price of natural gas and the need for a cleaner technology to generate electricity has motivated the power industry to move towards Integrated Gasification Combined Cycle (IGCC) plants. The system uses a low heating value fuel such as coal or biomass that is gasified to produce a mixture of hydrogen and carbon monoxide. The potential for efficiency improvement and the decrease in emissions resulting from this process compared to coal-fired power plants are strong evidence to the argument that IGCC technology will be a key player in the future of power generation.

In addition to new IGCC plants, and as a result of new emissions regulations, industry is looking at possibilities for retrofitting existing natural gas plants. This paper studies the feasibility of retrofitting existing gas turbines of Natural Gas Combined Cycle (NGCC) power plants to burn syngas, with a focus on the water/steam cycle design limitations and necessary changes. It shows how the gasification island processes can be treated independently and then integrated with the power block to make retrofitting possible. This paper provides a starting point to incorporate the gasification technology to current natural gas plants with minor redesigns.

### INTRODUCTION

A world under constant development is completely dependent on the available energy to power the new technologies. Several energy sources such as solar, wind, hydraulic, nuclear and fossil fuels are converted to electricity as it is the most valuable form of energy because it can be easily transmitted and applied in many ways. Different technologies have been developed to take advantage of renewable energies, but fossil fuels still occupy the first place on the list of energy sources to produce electricity. Natural gas has been used for years to power gas turbines in simple and combined cycle applications. Some years ago, natural gas was abundant and the excessive supply kept its price at a reasonable level for independent

power producers. In the last few years the supply has decreased, and the constant demand has elevated the price to levels that decrease the cost competitiveness for natural gas combined cycle plants. This trend, together with the need for cleaner technology, motivates the power generation industry to move into IGCC Plants.

The gasification process uses fuels with low heating value such as coal or biomass. Coal is commonly used due to its low price and abundant reserves in the USA. The exothermic gasification reaction produces a high temperature Synthetic gas (Syngas) that can be burned in a gas turbine. Siemens has significant experience in the gas turbine area with more than 300,000 hours operating with Syngas [1]. The SGT6-5000F has been very successful in the 60 Hz natural gas based combined cycle market and has all the necessary features to be integrated into an IGCC plant.

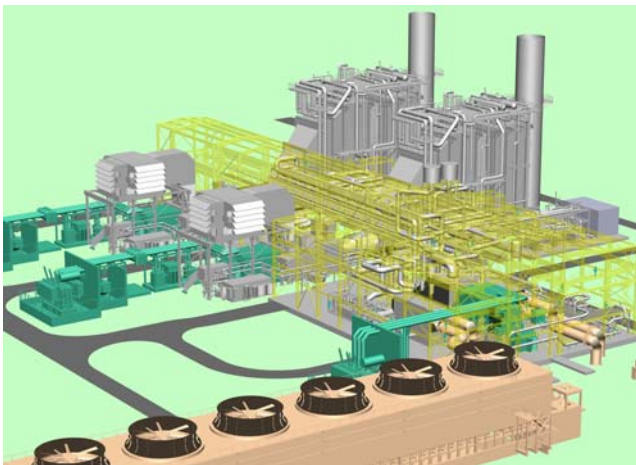
The gasification island is composed of systems such as the Air Separation Unit (ASU), Acid Gas Removal (AGR) and Syngas Cooler that can be integrated with the combined cycle to increase the plant output and efficiency. Full plant integration requires changes in the design of the bottoming cycle (including steam turbine, heat recovery steam generator, air side integration and balance of plant equipment) that will increase the price of retrofitting an existing natural gas combined cycle (NGCC) plant. The level of integration of the gasification island with the power block is directly proportional to the increase in cost of retrofitting the power plant. Electric plants that are burning natural gas will benefit with a design that uses Syngas fuel and minimizes the changes in their current equipment. This paper explains different ways to retrofit an existing NGCC plant to IGCC. It focuses on the simplest solution of having a completely independent gasification island connected to the power block by a fuel line, which presents the option that requires the least capital investment. Several issues related to the bottoming cycle are studied to evaluate the feasibility of retrofitting the plant under different gas turbine conditions, specifically exhaust flow and temperature.

## EXISTING NGCC PLANT BASIS

The power plant used as a baseline for this study is the SCC6-5000F 2x1 Reference Power Plant. It is a multi-shaft combined cycle plant consisting of the following major equipment:

- Two Siemens SGT6-5000F gas turbines (GTs) equipped with dry-low NOx combustion system and upstream inlet air evaporative coolers.
- Triple pressure reheat, heat recovery steam generator with an HP once through evaporator system, IP and LP drum type evaporators, an SCR, and IP and LP kettle boilers.
- One SST6-5000 type steam turbine with a two-case, reheat, opposed flow HP-IP, double-flow LP steam turbine design.
- Three (3) SGen6-1000A Generators for each of the Gas Turbines and Steam Turbine.
- A steam surface condenser with mechanical vacuum pumps for air removal and a mechanical draft cooling tower for heat removal.

Figure 1 presents a 3D model of the reference plant.



**FIGURE 1. SCC6-5000F REFERENCE NATURAL GAS COMBINED CYCLE PLANT.**

While operating on natural gas, this plant has an ISO rating of approximately 582 MW at an efficiency of 56.6%, with NOx emissions below 4 ppmvd @15%-Vol O<sub>2</sub> (with SCR).

It is designed to operate across wide ambient temperature (-5°F to 105°F) and barometric pressure (sea level to 3300 ft.) ranges. Necessary systems for 100% steam turbine bypass operation and fast start-up capabilities are also present.

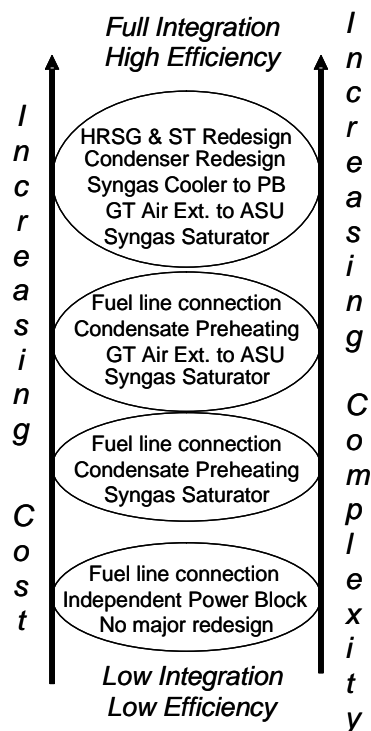
The Heat Recovery Steam Generator (HRSG) and balance of plant equipment are designed to operate at optimal conditions according to the gas turbine exhaust flow and temperature ranges seen when firing natural

gas. Operating the current gas turbine with Syngas fuel will present some changes in the exhaust conditions that will impact the performance of the bottoming cycle. Furthermore the different interfaces between the gasification island and the power block can increase the complexity of the retrofitting, increasing the cost coming from the necessary redesigns. The standard plant described above is used in this study to present how to retrofit a current operating NGCC with IGCC technology applying minimum changes in the design of its components.

## PLANT INTEGRATION

A power block designed to operate on Syngas will typically have several integration points with the gasifier and ASU islands. The following are the components that are interconnected:

- Fuel supply: the fuel coming from the Syngas must be diluted to the target heating value.
- Air Extraction to ASU: Part of the air used by the ASU to generate the oxygen can be extracted from the compressor of the gas turbine, reducing the auxiliary load consumed by the ASU's main air compressor.
- Air Extraction Cooling Systems: Any air extracted from the GT compressor can be used to produce IP and LP saturated steam in kettle boilers to improve the performance of the bottoming cycle. The air is cooled in a sequential way in order to minimize the temperature difference between the air and the water/steam increasing the heat transfer efficiency.
- Condensate preheating: The cleaning process that the Syngas undergoes requires heat rejection that is typically serviced by the cold water that comes from the condensate system. After leaving the coolers of the gasification island, the warm condensate is returned to the water/steam cycle.
- Syngas Cooler: After leaving the gasifier, the gas is cooled down to approximately 700°F by high pressure water. The saturated steam produced is sent to the bottoming cycle.
- Syngas Saturator: Part of the dilution of the fuel is done by moisture added in the Syngas saturator in an endothermic evaporation.



**FIGURE 2. INTEGRATION OPTIONS AND COMPLEXITY**

In deciding which, if any, streams to integrate when retrofitting the plant, several factors bear consideration. As a rule of thumb, integrating these streams between the blocks will result in higher plant output and efficiency, but at the cost of complexity. Complexity increases the demands for proper plant controls, and amplifies the risk of plant operability issues. Figure 2 shows a schematic of how the cost, complexity and efficiency are related to the level of plant integration. As shown in the figure, the biggest complexity appears with the integration of the Syngas Cooler to the bottoming cycle. This component presents a particular challenge. In order to increase plant efficiency, modern NGCC are normally designed with HP system pressures in excess of 2000 psia. Syngas coolers, which receive HP economizer outlet feedwater and return saturated steam to the HP system, are typically designed with a Maximum Allowable Working Pressures (MAWPs) around 1800 psia. A reduction of HP system pressure, a redesign of the syngas cooler, or both may settle this issue. The duty of the Syngas Cooler is around 100 MW per gas turbine, producing a significant amount of high pressure saturated steam going to the bottoming cycle. For retrofitting cases, the design of the HRSG and possibly the steam turbine may not be able to admit this new mass flow, and will definitely result in non-optimal operating conditions, such as colder main and reheat steam temperatures. Design changes in the HRSG would be required to optimize the bottoming cycle with the added syngas cooler steam flow.

The next level of integration does not include the Syngas Cooler, but still has the Air Extraction cooling system. Extracting the air from the gas turbine does not impose a major change of this component because it can be taken from the existing man-way access openings. These kettle boilers do not present a limitation on the pressure side and the amount of steam generated may be supported by the current design of the HRSG and steam turbine. The increase in steam flow will raise the pressure at the inlet of the turbine increasing the power output and bottoming cycle efficiency. Condensate preheating and Syngas saturator heat addition are considered components of less complex integration that will enhance the performance of the overall plant.

Another factor that enters into the equation of integration is off-design behavior. In contrast to a greenfield unit where interactions between the gasifier, ASU, and power block have been pre-planned, a power block designed to run on natural gas will not necessarily be able to service the gasifier requirements or receive the gasifier/ASU return streams at off-design conditions present at ambient extremes, start-up and shutdown, part load and steam turbine bypass modes among others. For these reasons, the authors contend that minimal integration between the power block, gasifier and ASU islands is the most reasonable approach in the case of retrofitting.

The option that represents the lowest cost to an existing power block and hence the lowest performance benefit would be to have a completely independent gasification island that will only be connected to the power block by a fuel line. The fuel supply will already be diluted to the required heating value, and no major redesigns will be done to the bottoming cycle. The primary modification will be on the combustor and fuel nozzles of the gas turbine to make it run in Syngas. This option has been previously analyzed by Jacobs Consultancy and was found to be a potential commercially viable concept [4]. Minimizing the interaction between the gasification island, ASU and power block enables current natural gas combined cycle plants to operate on Syngas with minor redesigns in the bottoming cycle, because the impact will be limited to the increase in exhaust flow and temperature going into the HRSG. Petrochemical industries involved in the gasification process will be able to sell independent gasification islands that can supply Syngas to several power plants around the area. The reduction in design changes makes this concept more feasible and economically attractive for the introduction of IGCC technology to current natural gas operating plants. Layout and space considerations are also essential in determining the feasibility of retrofitting. The coal handling and storage, fuel preparation, gasification, slag handling, acid gas removal, air separation, ambient heat rejection, and related systems will require approximately 30-40 acres of space in addition to the NGCC plant footprint.

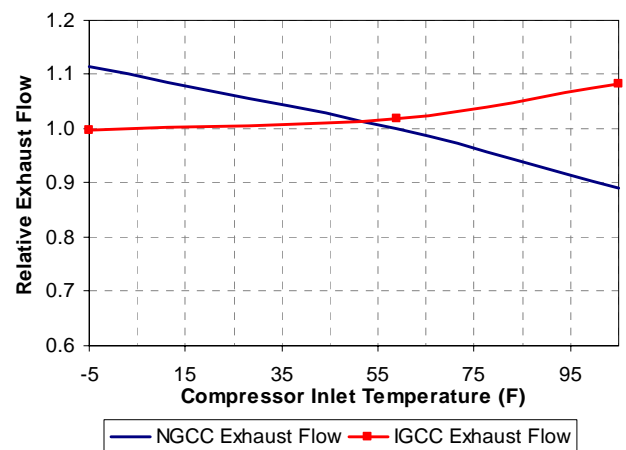
## IMPACT ON GAS TURBINE

As the heart of the power block, the gas turbine is essential to any study of retrofitting. As Gadde et al [1] illustrate, the changes that must be done to the gas turbine to operate in Syngas are minor. The only components that require adjustments are the combustor and the fuel nozzles, decreasing the complexity of retrofitting the gas turbine. One of the differences between the Syngas fuel and the natural gas is its energy content. The heating value of the Synthetic gas is low compared to that of natural gas, requiring a larger fuel flow supply in order to achieve flame temperature and maintain constant energy input to the gas turbine. Another variation that the Syngas flow has is its composition and higher level of sulfur. The consequence of increased sulfur content when combined with the ammonia slip coming from the selective catalytic reactor (SCR) is the production and deposit of ammonium bisulfate salt on the cold surfaces of the HRSG. These salt deposits can lead to corrosion and potentially to forced outages for water wash cleaning of the HRSG. It is estimated that continuous operation of the gas turbine with 40 ppm SO<sub>x</sub> and 5 ppm ammonia slip from the SCR would require 13 outages per year [2]. The sulfur content of Syngas leaving a typical acid gas removal system (where sulfur content is not a concern) is approximately 40 ppm (compared to 4.2 ppm for typical natural gas) [3]. Techniques such as Selexol (physical absorbent) and MDEA (chemical absorbent) are being used for the cleaning process. Further research must be done to develop strategies that produce Syngas with lower sulfur content (better acid gas removal) or to prevent salt formation in the cold surfaces of the HRSG. One approach that has been followed to attack the sulfur content issue is to increase the recirculation in the condensate pre-heater to raise the stack temperature to levels where no deposition can occur. This approach solves the problem of corrosion but decreases the performance of the bottoming cycle because the energy contained in the exhaust gas is not being completely used; however, it is the most economic solution because no changes in the current design must be done. Advanced technologies such as catalytic combustors, premix nozzle and trapped vortex for emissions controls are currently being researched under DOE funding to reduce the NO<sub>x</sub> under 3 ppm without diluents and without SCR [3].

In order to control the NO<sub>x</sub> emissions by controlling the peak flame temperature, it is necessary to dilute the fuel before injecting it into the gas turbine. The dilution can be done with nitrogen from the air separation unit or steam from the Gasifier island or bottoming cycle. The increased fuel flow added to the inert stream used for dilution produces yet a larger mass flow through the gas turbine that yields increased generator output and exhaust flow. On cold days, the amount of air inducted by the compressor is larger due to constant volumetric flow through this component and the increase in air density. The mass flow can be controlled by the Inlet Guide Vanes (IGV) in order to level the flow across

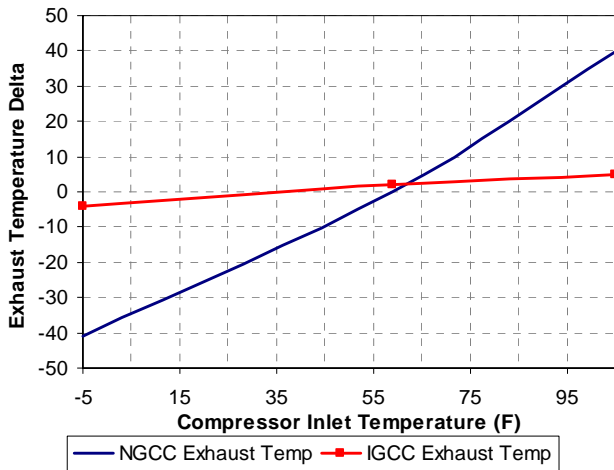
varying ambient conditions. Fuel dilution is required to reach the necessary low heating value that varies according to the water content in the flow. The level of moisture in the fuel has an impact on the bottoming cycle because the increase of water content in the exhaust gas enhances the heat transfer in the HRSG increasing the steam production and therefore the power output of the steam turbine. As Gadde mention in his paper, the gas turbine design is not significantly affected by the Syngas operation and can be retrofitted for this new technology. The interconnections between the gas turbine and the bottoming cycle will impact the operating conditions of the water/steam cycle due to changes in the following variables: increase in exhaust flow, exhaust temperature and gas turbine cooling. In order to understand the major differences between NGCC and IGCC a model of an SCC6-5000F reference plant was used. The model simulates the steady-state operation of IGCC and NGCC at different compressor inlet temperatures using the same HRSG and steam turbine design. No evaporative cooler is used and no air extraction is done for the IGCC cases. The values are shown relative to the 59°F NGCC case.

Figure 3 shows a graph of the relative change in exhaust flow rate as a function of the compressor inlet temperature.



**FIGURE 3. RELATIVE EXHAUST FLOW VARIATION VS. COMPRESSOR INLET TEMPERATURE.**

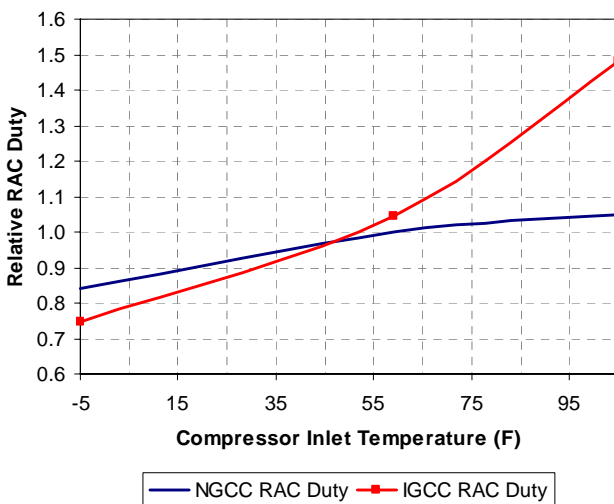
As shown in the plot, the exhaust mass flow of the natural gas case decreases with an increase in ambient temperature. This behavior is a consequence of the constant volumetric flow through the compressor and the reduction in mass flow going into it, due to the drop in air density. For the IGCC case, as explained above, the mass flow remains relatively constant by controlling the Inlet Guide Vanes (IGV's). The figure shows that the maximum flow with the IGCC case is similar to the maximum flow obtained in the NGCC case (-5°F). This means that it is highly probable that the HRSG design would be able to handle the hot day increase in exhaust flow with little or no modifications. Figure 4 shows the exhaust temperature behavior as a function of compressor inlet temperature.



**FIGURE 4. EXHAUST TEMPERATURE DELTA AS A FUNCTION OF COMPRESSOR INLET TEMPERATURE.**

The Y-axis represents the temperature difference relative to the NGCC 59°F case. As can be seen in the NGCC case, exhaust temperature increases proportional to the ambient temperature, but for the IGCC case is relatively constant at an average temperature. The highest temperature obtained in the NGCC case is higher than the one for the IGCC case, increasing the feasibility of retrofitability.

Figure 5 presents the relative increase of the necessary external heat extraction from the turbines (Rotor Air Cooler duty) for each of the cases as a function of compressor inlet temperature.

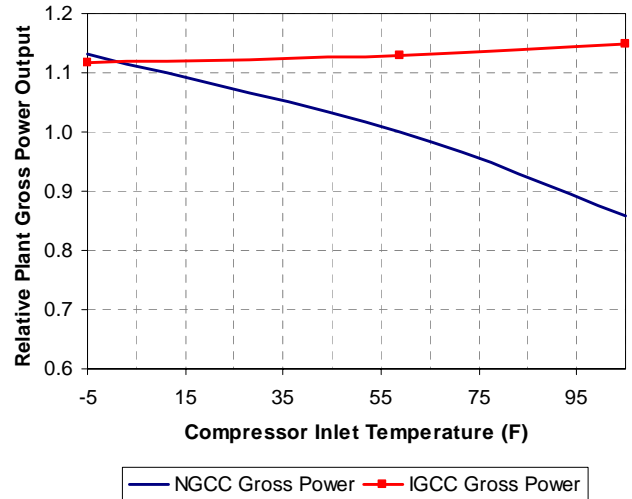


**FIGURE 5. RELATIVE CHANGE OF ROTOR AIR COOLER VS. COMPRESSOR INLET TEMPERATURE.**

As shown in Figure 5 the required duty of the Rotor Air Cooler (RAC) increases significantly when retrofitting the plant. At increased compressor inlet temperatures, the duty is approximately 50% higher with IGCC than NGCC. It may be possible that these higher duty requirements could be handled by the existing system; however, the addition of heat exchange/rejection equipment may be necessary.

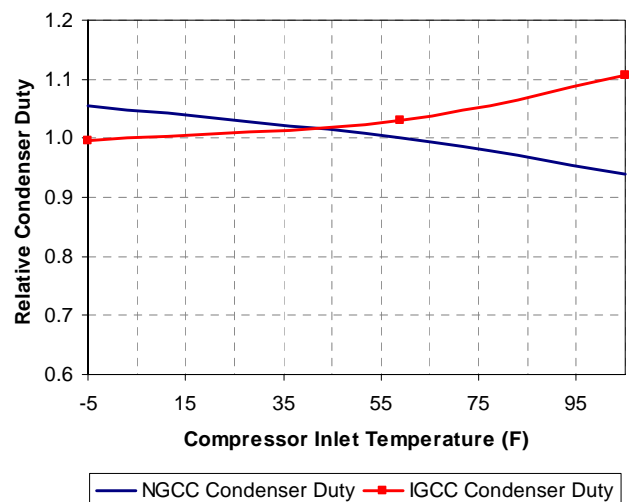
## IMPACT ON PLANT PERFORMANCE

It was shown above that the thermal equipment may be able to handle the IGCC engine operating conditions; however two components of the plant need to be studied in further detail to determine if they are capable of handling the retrofitted gas turbine. These components are the generators and the condenser. Figure 6 shows the relative increase in the gross power output of the total plant.



**FIGURE 6. RELATIVE GROSS POWER OUTPUT AS A FUNCTION OF COMPRESSOR INLET TEMPERATURE.**

As shown in Figure 6, the total power of the IGCC plant is approximately constant because the gas turbine is operating at a limit that should not be exceeded. The maximum gross power output for the NGCC case is similar to the IGCC case.



**FIGURE 7. RELATIVE CHANGE OF CONDENSER DUTY AS A FUNCTION OF COMPRESSOR INLET TEMPERATURE.**



During a hot day, the plant can be operated at part load to maintain the generator limits, or an evaluation of the design margin of the generator must be made to determine the feasibility of using the same component for the retrofitted plant.

Figure 7 shows the behavior of the condenser duty for the two cases. The maximum condenser duty for the IGCC case is around 10% higher than the ISO NGCC case. Once again, a detailed study of the specific site and components (ST, generator, HRSG, etc.) must be done to study the feasibility of retrofitting

## SUMMARY

The feasibility of retrofitting an existing Natural Gas Combined Cycle plant has been studied. Siemens has determined that its SGT6-5000F gas turbines can be used with Syngas fuel if the combustor, fuel nozzles and control system are changed, which can be accomplished without a cover lift. Several options for integration have been discussed and they relate to the level of complexity and cost incurred. The minimal integration case was chosen as the most feasible alternative for retrofitting because it gives the possibility of using the current bottoming cycle equipment by having a completely independent gasification island.

This independency gives the flexibility to Syngas producers of having a self-sustaining Gasifier/ASU plant that can supply fuel to several retrofitted power plants. Based on these evaluations, Siemens Power

Generation sees IGCC refueling of existing SCC6-5000F as an attractive and viable option to increase the operation of under-utilized power generation assets.

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