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Flexibility and efficiency of a steam turbine extraction vs gas fired generation as the steam source for post combustion CO_2 capture on a coal fired power plant

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Abstract

CO_2 emissions from electrical power generation must be reduced if global climate change mitigation targets are to be met. Expansion of renewable sources of power generation and the application of carbon capture and sequestration are two strategies required to reduce the CO_2 emissions from this sector. As the penetration of renewable resources increases, non-renewable generation will need to become more flexible in order to back-up the intermittent renewable energy sources.

Post combustion CO_2 capture is the only proven full scale option currently available for reducing emissions from existing coal fired power plants. Post combustion capture processes however require significant quantities of thermal energy (or steam) to regenerate the solvent used for CO_2 capture. This requirement for thermal energy can represent almost half of the de-rate associated with CO_2 capture. Numerous studies have evaluated sources of this thermal energy; such as the existing steam turbine, or the integration of new gas fired sources. Most studies that have compared these sources of thermal energy have evaluated only performance at full load but this study focuses on flexibility and efficiency of these two configurations over a broader range of output. The conclusion of the study is that the existing steam turbine of the associated power plant can be re-engineered to become a more efficient and a more flexible source of the thermal energy than the addition of a gas fired generation source.

Keywords: Carbon Capture and Storage; Post Combustion Capture; Steam Source; Flexibility; Efficiency; Combined Heat and Power

1. Introduction

Global warming has necessitated a reduction in greenhouse gas emissions. Generation of electricity is a significant source of such emissions and coal fired power generation accounts for 40% of global electricity generation. Greenhouse gas emissions from the electricity sector can be reduced by the expansion of non-emitting sources such as solar, wind and nuclear and by the implementation of Carbon Capture and Sequestration (CCS) on fossil fuelled sources of electricity. Solar and wind are non-dispatchable and intermittent sources of electricity and traditional fossil fired generation sources may be called on to be flexible to back-up these intermittent generation sources. Fossil fuelled generation however will require CCS if it is to continue to operate and these CCS systems will therefore need to be flexible and efficient if fossil fuel fired generation is to continue to be viable.

Post Combustion Capture (PCC) is the only technology that has been demonstrated at a commercial scale on coal fired power generation, at the Boundary Dam ICCS Project near Estevan, Saskatchewan and the Petra Nova CCS

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Project at the W.A. Parish power plant near Houston, Texas. Any very near-term application of CCS on coal fired power will most likely also use PCC technology.

PPC with amine solvents requires significant quantities of thermal energy to regenerate the solvent and this steam is the cause of almost half of the de-rate resulting from carbon capture. The source of this steam has a significant impact on the cost of this steam and therefore on the economics of CCS.

2. Sources of steam for capture process

The two potential sources of steam for the regeneration of the solvents for post combustion carbon capture are extraction of steam from the turbine of the existing coal fired power plant, or the addition of a new gas fired source to produce the steam.

2.1 Coal plant sources of steam for capture process

A coal fired power plant uses steam as the working fluid to convert the thermal energy from the combustion of the fuel to mechanical energy in the steam turbine which drives the electrical generator. The high heat capacity of steam also makes it an ideal medium to provide the thermal energy for solvent regeneration. As the steam is the driving force for the steam turbine and generator, the most efficient configurations for supplying steam for solvent regeneration extract this steam at as low a pressure as possible while still adequate for the reboiler of the capture system. This allows the steam to first do as much work as possible in the turbine.

The most common source of steam assumed for solvent regeneration is the cross-over which is the large diameter duct or pipe that connects the output of the Intermediate Pressure (IP) turbine to the inlet of the Low Pressure (LP) turbine. This is an accessible location for this large extraction and the pressure is typically suitable for use in the reboiler. Taking a large extraction of steam, which can be up to one third or more of the normal flow in the cross-over, can have a significant impact on the steam turbine. For most steam turbines the volumetric flow through each stage is relatively constant over the operating range of the turbine, with the pressure at any point increasing in proportion to the mass flow. When a large extraction is taken at the cross-over, the mass flow to the LP turbine decreases, also decreasing the pressure at the LP turbine inlet or the cross-over. The mass flow through the IP turbine however remains largely unchanged as does the inlet pressure to the IP turbine. The extraction therefore results in dramatic increase in the pressure ratios across the last stages of the IP turbine, and the bending stresses in the blades can exceed the design strength. The change in pressure ratios also has an impact on the efficiency of the last stages of the IP turbine, as the volumetric flows and velocities in these stages are higher than design. The reduced pressure in the cross-over due to the extraction may become too low for efficient use by the reboiler used to regenerate the solvent.

One solution is to install a valve in the cross-over, to maintain the pressure at the outlet of the IP turbine to mitigate pressure ratio increases and blade stresses and this valve may also be used to maintain the pressure in the cross-over high enough for the reboiler. This arrangement is illustrated in Figure 1 and is typically referred to as a controlled extraction. The problem with this arrangement is that the valve can introduce significant throttling losses which reduce the amount of work that can be extracted from the steam.

Another solution to problems with blade stresses is to modify the steam path including the rotating blades and stationary nozzles to accept the new flow conditions imposed by the steam extraction. This includes more robust blades in the last stages of the IP turbine with the appropriate geometry for the flow conditions expected when a large quantity of steam is extracted. Depending on the pressure required in the cross-over, changes may also be required to the initial stages of the LP turbine to provide the correct pressure without a throttling valve. This would be called an uncontrolled extraction and is illustrated in Figure 2. The new steam turbine installed on Boundary Dam Unit 3 (BD3) for the Boundary Dam ICCS Project, which was the first commercial scale application of CCS on a coal fired power plant, has an uncontrolled extraction with these features. The two issues with the steam turbine configuration for BD3 were the cost of modifications to feedwater heating plant that interfaces with the steam turbine and the fact that BD3 was optimized for full load operation. When the load on BD3 drops below about 80%, the pressure in the cross-over drops off to the point that the capability to regenerate the solvent and the capture rate are curtailed dramatically. An uncontrolled extraction as large as required for post combustion capture was also thought to be very difficult to retrofit to an existing steam turbine.

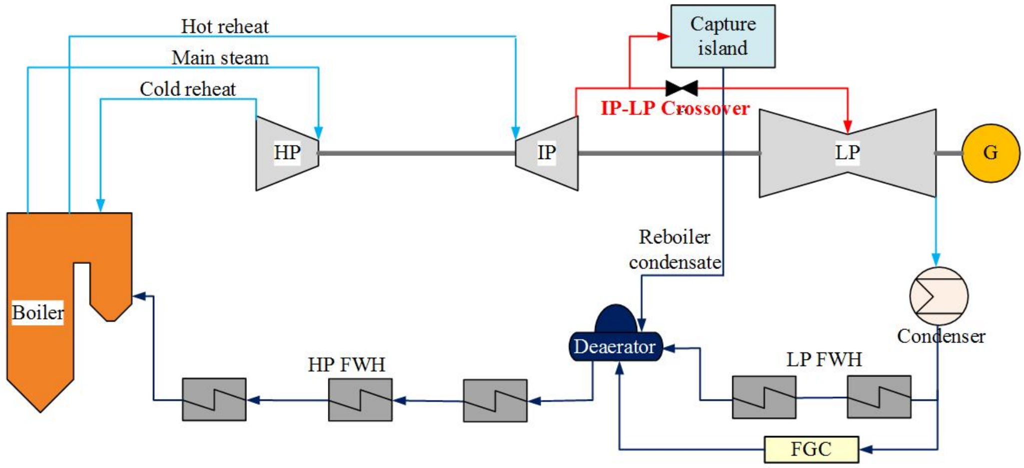

Figure 1. Controlled steam extraction from cross-over

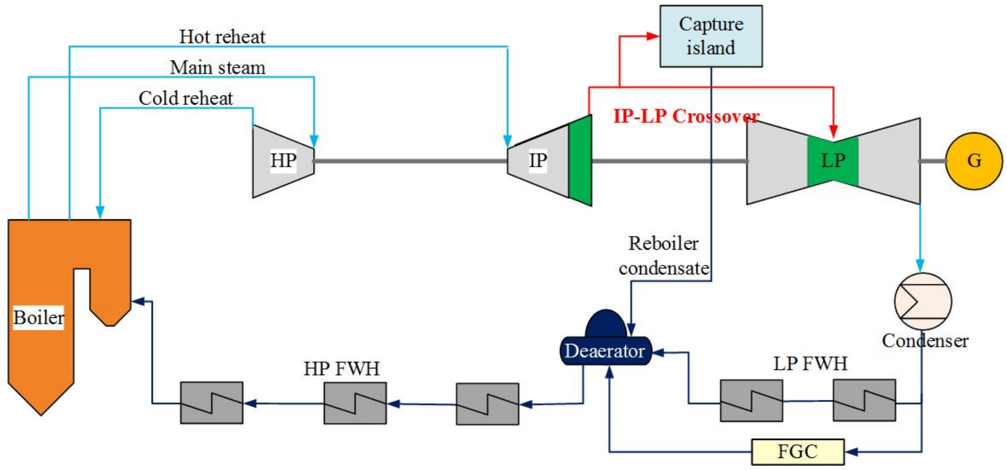

Figure 2. Uncontrolled steam extraction from cross-over with IP and LP turbines optimized to provide correct pressure

A feasibility study on the SaskPower Shand Power Station focused significant efforts on combining the best features of both a controlled and uncontrolled extraction in a method that was also easy to retrofit to an existing steam turbine. The solution was to install a new rotor and inner casing with more robust IP exit stage blades in High and Intermediate Pressure (HIP) turbine casing, and to replace the first stages in the LP turbine to produce the correct cross-over pressure for the large process extraction. The HIP rotor and inner casing can be replaced without any modifications to the turbine outer casing or connections to the steam turbine. The first stages of the LP turbine can be replaced on the existing rotor. This scope of modification is quite similar to a midlife retrofit or upgrade to a power plant and can be achieved in roughly a 65 day outage. As most of the changes are “bolt in” there is minimal onsite labour. This retrofit also allows the recovery of efficiency degradation in a steam turbine that is approaching midlife, and allows for new blade technology and a dense pack arrangement which increases the number of stages and the turbine cycle efficiency. To mitigate the limitation experienced on BD3 with reduced capture rate at part loads, the design includes a butterfly valve installed in the cross-over to maintain pressure to that required by the capture process. The valve would be partially closed when capturing at reduced loads and the pressure losses across the open valve at full load are minimal. The study included validation and pricing of these concepts by the Original Equipment Manufacturer (OEM) of the steam turbine, and the OEM completed numerous heat and mass balances for the upgraded turbine which are the basis of the steam turbine extraction configuration assumed in this paper.

2.2 Gas fired sources of steam for capture process

There are numerous configurations available to supply the steam for solvent regeneration from new natural gas fired generation. The first option for a gas fired source would be natural gas fired boiler. While simple it would not be a very high valued use of a fuel such as natural gas. The more common option would be to apply a natural gas fired steam turbine in a Combined Heat and Power (CHP) arrangement. The gas is combusted in the gas turbine and the heat in the exhaust gases are used in a Heat Recovery Steam Generator (HRSG) to produce steam. The steam produced can be first used in a steam turbine to generate additional power and a portion or all of this steam can be used for the capture process. Using the high quality thermal energy in the gas turbine first provides better value from the use of this fuel, and including a steam turbine further improves the use of this energy, with only the lowest quality heat then being used by the capture process.

One of the challenges with using an efficient gas fired source is that to be efficient, the proportion of low grade heat is reduced and the gas fired source may actually be generating much more power than the coal fired power plant for which CCS is being supported. This may be acceptable if there is consistent demand for all the power that will be produced and if the power produced by this gas turbine is competitive with other sources available to the market, but this is not always the case.

Table 1 compares the size and efficiency of a range of gas fired sources that were part of this study.

Table 1. Cost of steam vs gas turbine size

Gas Turbine Model		GE 7F.03	GE 7F.04	GE 7F.05	GE 7HA.01
Net Output without CHP (from GTPro)	MW	242.4	270.7	314.2	377.3
Heat Rate without CHP (from GTPro)	kJ HHV/kWh	7,237	7,060	7,011	6,788
Steam Turbine in CHP Arrangement	Type	None	Back Pressure	Back Pressure	Condensing
Cost of Process Steam with CHP at Full Load	MW_{el}/MW_{th}	41.5%	26.6%	25.5%	24.7%

The Petra Nova CCS Project at the W.A. Parish Power Plant, which is currently the world's largest CCS project on coal fired power, uses a GE 7EA gas turbine plus a duct burner upstream of the HRSG to generate the steam required by the capture process [1]. The Petra Nova project does not make use of a steam turbine and this may have been a choice to minimize the size of this unit which must run to support the capture process.

The capacity of gas turbines is very dependent on ambient conditions, and gas turbines are only available in a limited number of sizes making it difficult to match a gas turbine to a process steam demand. Duct burners are therefore commonly applied to boost steam production though duct burning is not as an efficient use of gas. For the case study presented in this paper, the initial assumption was a GE 7F.04 gas turbine with a HRSG and a back-pressure steam turbine. Subsequent sensitivity analysis showed marginally lower costs of steam with the larger gas turbine options, though these configurations would also produce more power than the coal plant used in this case study.

3. How to evaluate options

There have been numerous studies [2] comparing the performance between the existing steam turbine as the source of steam for the capture process and a new gas fired source.

3.1 Previous works

The most common metric found in previous works [2] for comparing the existing steam turbine with a gas fired source is the overall efficiency or heat rate and the capital cost. One problem with this comparison is that a Natural Gas Combined Cycle (NGCC) is inherently much more efficient and lower in cost on a per MW basis than a coal plant with CCS, and if a NGCC is applied in a CHP arrangement, and the overall heat rate and emissions are compared, the CHP does look much better. These studies have not looked at the impact the regeneration steam duty has on the performance and flexibility of the NGCC plant.

3.2 New evaluation methods

To provide a better comparison of the two steam sources this study has two unique features. The first is that it compares the combined output and performance of a coal plant with CCS and a new independent NGCC where the coal plant supplies its own steam for the capture process, to a case where the NGCC through a CHP configuration supplies the steam for the capture process. The second feature of this study is that it evaluates performance over range of loads to illustrate the impact of the CHP arrangement on the flexibility and efficiency of the gas source.

3.2.1 Tools

The study made use of the modelling software GateCycle for the analysis of the performance of the power plant steam turbine and the software packages GTPro and GTMaster by Thermoflow for the performance of gas turbine configurations. Both software packages are used extensively in the electrical power generation industry for thermodynamic performance analysis.

The GateCycle models were based on the updated heat balances by Mitsubishi Hitachi Power Systems for the proposed upgrades to optimize this steam turbine for carbon capture. GateCycle was also used to optimize the heat integration including heat recovered from flue gas cooling.

The gas turbine performance models used data built into Version 27 of GTPro and GTMaster for specific gas turbines and while this data is based on turbine performance information from the Original Equipment Manufacturer (OEM), it may not reflect the latest performance data or may differ slightly from OEM performance at off design conditions. This quality of information was however thought to be sufficient for this study.

3.2.2 Cost of steam

For the purposes of this study we have defined the cost of steam as the ratio between the reduction in net electrical output resulting from the steam extraction and the thermal duty of the reboilers in the capture system.

When the steam is sourced from coal plant's steam turbine the boiler fuel input is held constant for each load case. The coal plant cases were run with and without low pressure condensate preheating to distinguish the impacts of the process steam extraction from the effects of the waste heat integration.

The gas turbine options included additional fuel for duct firing at times to meet the steam demands of the capture system, when the heat in the exhaust gases from the gas turbine were not sufficient. This additional fuel input complicates the cost of steam calculation, but the additional gas that was required was translated into MW_e at the heat rate of a stand-alone combined cycle plant of the same size without process extraction at the same gas turbine load. This was felt to be a reasonable assumption.

The formula applied follows.

$$\text{Cost of Steam} = \frac{\left[(MW_{e_{NGCC}} - MW_{e_{CHP}}) + \frac{(MW_{th_{CHP}} - MW_{th_{NGCC}})}{Heat\ Rate_{NGCC}}\right]}{MW_{th_{Process}}} \tag{3.1}$$

Where: $MW_{e_{NGCC}}$ = Net electrical output of NGCC plant

$MW_{e_{CHP}}$ = Net electrical output from gas fired CHP

$MW_{th_{CHP}}$ = Fuel energy to gas fired CHP plant

$MW_{th_{NGCC}}$ = Fuel energy to NGCC plant

$Heat\ Rate_{NGCC}$ = Heat Rate of NGCC in kJ/kWh

$MW_{th_{Process}}$ = Capture process steam thermal duty

CHP represents the gas fired plant where this plant is providing the steam to the capture plant. NGCC represents a stand-alone natural gas combined cycle plant. All values in formula must be for the same gas turbine load case.

3.2.3 Flexibility

Flexibility is important for power generating facilities and is expected to become more important as the penetration of intermitent non-dispatchable sources of generation progresses. In the context of this study the focus is on the efficiency or cost of steam and the range of output or the ability to dispatch the coal and gas units independently.

4. Case study

We have designed a case study to more fully evaluate two potential sources of steam for solvent regeneration for a post combustion CO2 capture process installed on an existing coal fired power plant. The reference plant, capture technology and upgrades are as described below.

4.1 Reference plant for case study

The coal plant used in this case study is SaskPower Shand Power Station which is located about 12 km east of the Boundary Dam ICCS Project, the first commercial scale and only fully integrated CO_2 capture system installed on a coal fired power plant. Shand is a single unit 305 MW coal fired power plant burning a lignite fuel. It was commissioned in 1992 and has a main steam pressure 12,500 kPa and main steam and reheat temperatures of 538 C. The OEM for steam turbine was Hitachi and the turbine is a tandem compound double flow configuration. The plant normally operates between 75% and 100% of rated capacity with more time spent towards the upper end of this range.

4.2 Capture technology for case study

The study assumes an advanced amine capture technology, capturing 90% of the CO2 emitted from the plant over the operating range of 75% to 100% load. The study assumed that process steam to the reboilers will have a minimum pressure of 4.5 bara and the condensate returning from the reboilers is saturated at 3.5 bara.

4.3 Coal plant modification for case study

The coal plant is assumed to receive a steam path upgrade, replacing the HIP rotor and inner casing, and increasing the number of stages in the HP and IP turbine sections. The steam path upgrade is assumed to recover approximately 3% in output from turbine degradation. The LP turbine has been modified to provide at suitable pressure to a capture process without the need for throttling of the steam to the LP turbine for the full load case with capture, but a butterfly valve has been included to maintain the pressure in the cross-over for reduced load cases.

A Flue Gas Cooler (FGC) was included for heat recovery to low pressure condensate preheating to improve plant output. The FGC had a duty of 47 MW_{th}. Thermal integration for low pressure feedwater heating was only possible for the case with the coal plant supplying the capture process steam as the existing condenser and cooling tower do not have the capacity to support heat integration with the existing plant operating conditions.

4.4 Gas plant configuration assumptions for case study

The gas plant is assumed to be a General Electric 7F.04 gas turbine with a HRSG and steam turbine, with a gross output of 278 MW's at 15C and 565 m elevation. The steam temperature and pressure to the steam turbine is 566 C and 110 bara. The steam turbine is assumed to be a back-pressure turbine if it is to provide steam to the post combustion capture process through a CHP arrangement. For the comparison cases without CHP in the new gas plants, these NGCC configurations are assumed to have a condensing steam turbine. This size of plant was thought to be close to optimum for supplying steam to this capture process with minimal need for duct firing for the full load case, and minimal dumping of excess steam when the capture plant is at less than full load. Additional sensitivity cases were completed with the 7F.03 and 7F.05 gas turbines. A further sensitivity case was completed with a 7HA.01 which was large enough to support a condensing steam turbine concurrently with the full duty of process steam for capture.

4.5 Case design summary

Table 2. Case design summary

	CHP	Independent
CO_2 capture	90% from coal plant only	90% from coal plant only
Source of steam for capture process	HRSG and steam turbine of new gas fired plant	Re-engineered steam turbine in coal fired plant
Gas turbine cycle configuration	Gas turbine with HRSG and back pressure steam turbine	Gas turbine with HRSG and condensing steam turbine
Gas turbine model	GE 7F.04 for base case/GE 7F.05 for alternate case	GE 7F.04 for base case/GE 7F.05 for alternate case
Duct firing	As required to supply sufficient steam for capture process	No duct firing

4.6 Operating ranges considered

This study considered operation of the coal and capture plants at 75% and full load and operation of the new gas fired generation at loads between 40% and full load. Some of the CHP cases included supplemental duct firing.

5. Performance comparison

5.1 Full load performance

Table 3 compares the output of the CHP case to the independent case with the coal and capture systems and the gas turbine all at 100% of rated output. This table illustrates that the net output is similar for both cases but the fuel input to the duct burner increases the total fuel input to the gas cycle by 7.8%. This is a significant additional operating cost.

Table 3. Comparison of CHP and Independent cases with Shand coal plant and GE 7F.04 gas turbine – base case

		CHP		Independent		Difference	
		Coal	Gas	Coal	Gas	Coal	Gas
% Load		100%	100%	100%	100%		
Fuel Input	MW_{th}	3,230	575 *	3,230	531	0.0%	**-7.8%**
Gross Electrical Output	MW_e	317	246	283	278	-10.8%	13.2%
Net Electrical Output	MW_e	251	239	217	271	-13.6%	13.1%
CO_2 Produced	Mg/day	7,267	2,455	7,267	2,265	0.0%	-7.8%
CO_2 Captured	Mg/day	6,540	0	6,540	0	0.0%	
CO_2 Emitted	Mg/day	727	2,455	727	2,265	0.0%	-7.8%
CO_2 Emission Intensity	Mg/MWh	0.121	0.427	0.140	0.349	15.7%	-18.4%
		Sum of Coal + Gas		Sum of Coal + Gas		Difference	
Fuel Input	MW_{th}	3,805		3,761		-1.2%	
Gross Electrical Output	MW_e	563		561		-0.3%	
Net Electrical Output	MW_e	491		488		**-0.6%**	
CO_2 Produced	Mg/day	9,722		9,531		-2.0%	
CO_2 Captured	Mg/day	6,540		6,540		0.0%	
CO_2 Emitted	Mg/day	3,182		2,991		-6.0%	
CO_2 Emission Intensity	Mg/MWh	0.270		0.256		**-5.5%**	

* Increased fuel input relative to Independent case is the result of duct firing

Table 4. Comparison of CHP and Independent cases with Shand coal plant and GE 7F.05 gas turbine – alt case

		CHP		Independent		Difference	
		Coal	Gas	Coal	Gas	Coal	Gas
% Load		100%	100%	100%	100%		
Fuel Input	MW_{th}	3,230	615 *	3,230	612	0.0%	**-0.6%**
Gross Electrical Output	MW_e	317	287	283	337	-10.8%	17.4%
Net Electrical Output	MW_e	251	264	217	314	-13.6%	18.9%
CO_2 Produced	Mg/day	7,267	2,626	7,267	2,609	0.0%	-0.6%
CO_2 Captured	Mg/day	6,540	0	6,540	0	0.0%	
CO_2 Emitted	Mg/day	727	2,626	727	2,609	0.0%	-0.6%
CO_2 Emission Intensity	Mg/MWh	0.121	0.414	0.140	0.346	15.7%	-16.4%
		Sum of Coal + Gas		Sum of Coal + Gas		Difference	
Fuel Input	MW_{th}	3,845		3,842		-0.1%	
Gross Electrical Output	MW_e	604		619		2.6%	
Net Electrical Output	MW_e	515		531		**3.1%**	
CO_2 Produced	Mg/day	9,892		9,876		-0.2%	
CO_2 Captured	Mg/day	6,540		6,540		0.0%	
CO_2 Emitted	Mg/day	3,352		3,336		-0.5%	
CO_2 Emission Intensity	Mg/MWh	0.271		0.262		**-3.4%**	

* Increased fuel input relative to Independent case is the result of duct firing

A second sensitivity case was completed with a slightly larger GE 7F.05 gas turbine which required only about 1% of the total gas input as duct firing. The results of this case are presented in Table 4. The cost of steam was very similar to the GE 7F.04 with the key differences being a higher net output for the Independent case.

The main reason that the net output is higher for the Independent cases is better heat recovery in the HRSG relative to the CHP cases. The CHP configuration lacks an LP turbine and condenser so the only condensate going to the HRSG as feedwater is at the reboiler condensate return temperature of 137 C. This is much higher than the temperature of approximately 33 C assumed for the stand-alone cases from the condenser and results in much higher flue gas temperatures exiting the HRSG.

A third case was completed with a larger GE 7HA.01 gas turbine and this included an LP turbine, but while the condensate from the condenser was cooler, the flow rate was not high enough to produce a significant improvement in flue gas exist temperatures. The GE 7HA.01 has a combined cycle output of 377 MW's and a gas turbine much larger than this would be required to get more reasonable heat recovery in the HRSG.

5.2 Partial load performance

Partial load gas turbine performance considered loads of 75% and 100% for the coal plant and capture system and the full range of 40 to 100% gas turbine. The cost of steam for these cases is presented below in Figures 3 and 4.

The cost of steam from the coal plant is much lower than the cost from the gas plant at full load, and this is mainly due to poor heat recovery in the HRSG for the CHP cases. As the load on the gas turbine is reduced, substantial amounts of duct firing are required to support the required steam production. Duct firing however increases the temperature of flue gas to the HRSG, but the maximum practical temperatures was not determined within the scope of this study. In Figure 3 we have terminated the cost of steam curves for the GE 7F.04 and 7F.05 configurations when the gas temperature from the duct burner exceeded 800 C. This assumption would indicate that the 7F.04 could not maintain sufficient steam flow below 80% GT load. Another alternative investigated was the use of dilution air in the duct burner. The application of dilution air however substantially increased the cost of steam as the GT load decreased, due to increased levels of excess air and flue gas exhaust losses from the HRSG. This is also illustrated in Figure 3.

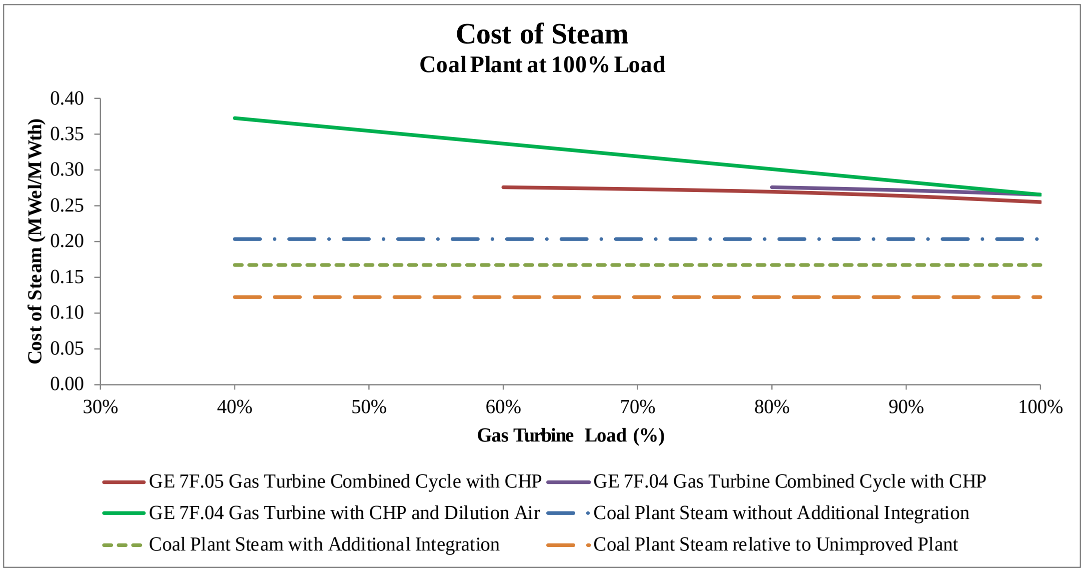

Figure 3. Cost of steam from various sources with coal plant at full load

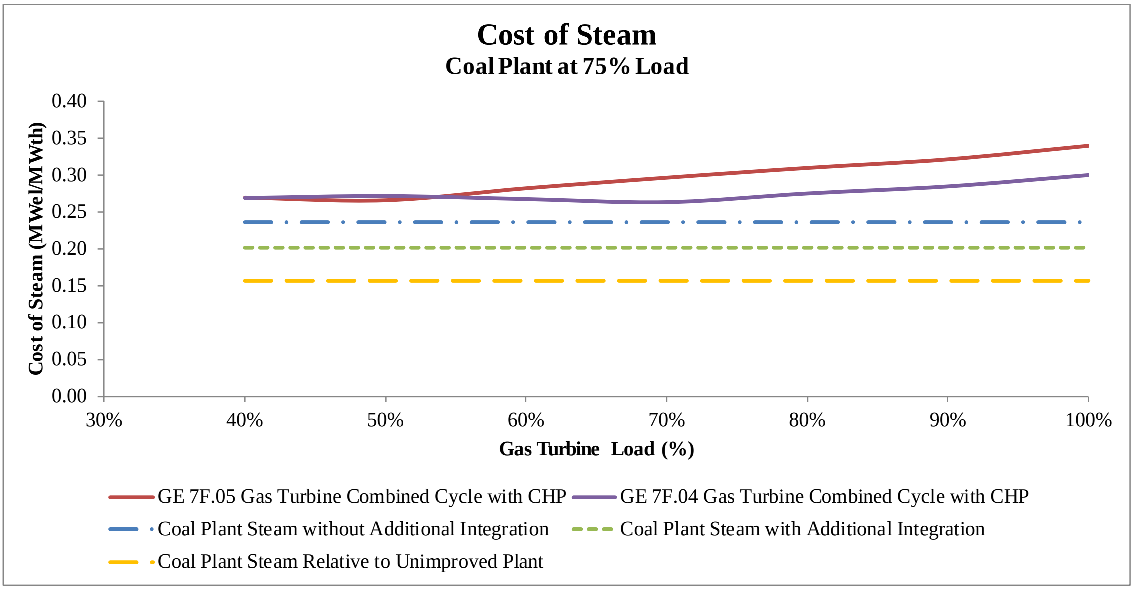

Figure 4. Cost of steam from various sources with coal plant at 75% load

When the load on the coal and capture plants was decreased to 75 % and the gas turbine was fired at higher loads, excess process steam was produced by the CHP arrangements and this excess was assumed to be directed to a dump condenser. This waste of heat increased the calculated cost of steam as illustrated in Figure 4. The magnitude and operating range where steam was dumped was greater with the 7F.05 gas turbine than it was for the 7F.04. A CHP arrangement that included a low pressure condensing steam turbine would mitigate this problem but this would be a much larger CHP plant.

The cost of steam from the coal plant increased significantly for the 75% case relative to the full load case. This was due to the need to throttle the steam flow at the cross-over to maintain steam pressure, and this throttling results in lost electricity production. This loss would increase further for capture at loads below 75% but the increase in cost or the lower load limits for effective were not determined as part of this study. At the 75% load case, the cost of steam was still less than for the gas fired cases.

6. Conclusions

This case study demonstrates that the steam cycle of a coal plant can be re-engineered to provide steam for solvent regeneration at a significantly lower cost in terms of lost electrical output than can be achieved by a gas fired plant. The gas fired CHP arrangement performs best when it was dispatched to loads similar to the coal and capture plants and the CHP arrangement would significantly impair the efficiency and flexibility of dispatch of the gas turbine.

The cost of steam for the coal plant as a source of steam does increase as the load on the coal plant is reduced below 75% and there are expected to be limits on how much the steam to the LP turbine can be throttled at reduced coal plant loads. Turndown limitations for a solvent based capture system are typically 50% and this may be the limiting factor on minimum load with capture.

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