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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

Background

- **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 require significant quantities of thermal energy (or steam) to regenerate the solvent used for CO_2 capture.
- **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 in a combined heat and power arrangement.**

Method to evaluate steam sources

There have been numerous studies [1] comparing the performance between the existing steam turbine as the source of steam for the capture process and a new gas fired source. The most common metric found in previous works [1] 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 combined heat and power (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.

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 (Independent Case), to a case where the NGCC through a CHP configuration supplies the steam for the capture process (CHP Case). 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.**

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. 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. 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.

Table 1. 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

Existing steam turbine as source of steam for capture process

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 Boundary Dam Unit 3 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.

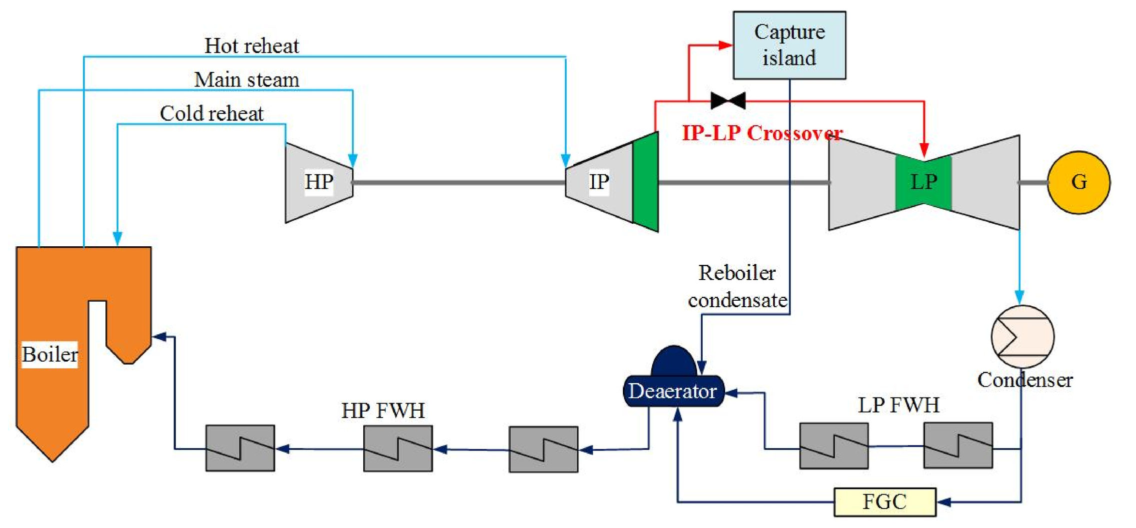

Figure 1. Extraction from cross-over with IP and LP turbines optimized to provide correct pressure

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. The more common option would be to apply a natural gas fired steam turbine in a combined heat and power (CHP) arrangement. 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.

Table 2 compares the size and efficiency of a range of gas fired sources that were part of this study.

Table 2. 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%

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.

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.

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

		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

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 in Figures 2 and 3. 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 2 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. 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 3.

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 for 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.

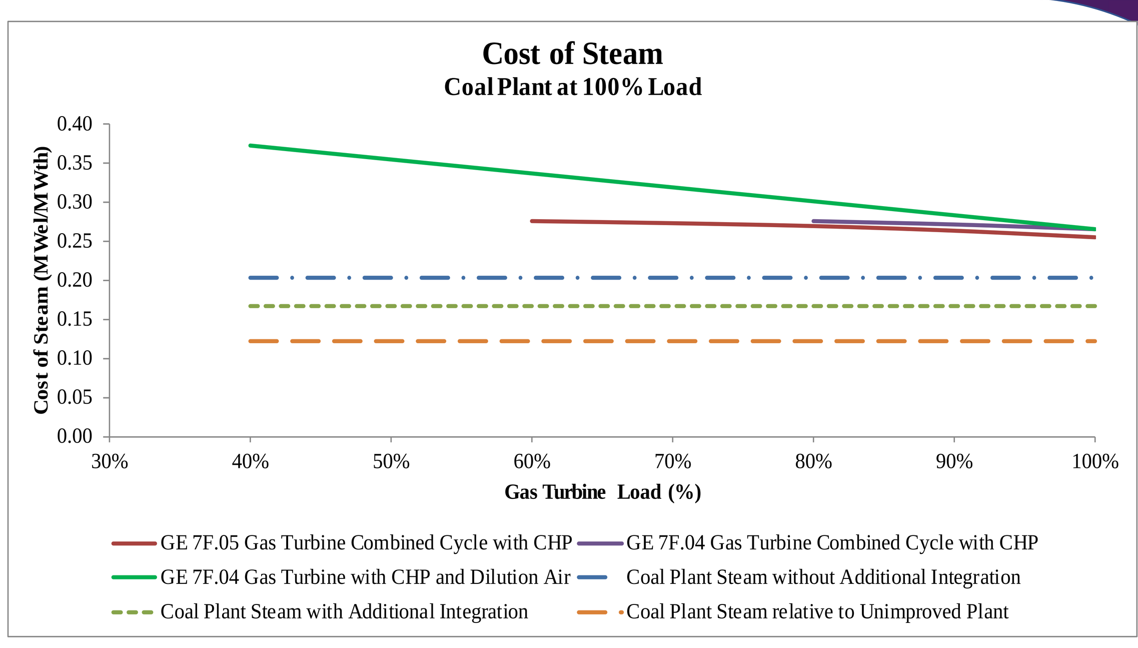

Figure 2. Cost of steam from various sources with coal plant at full load

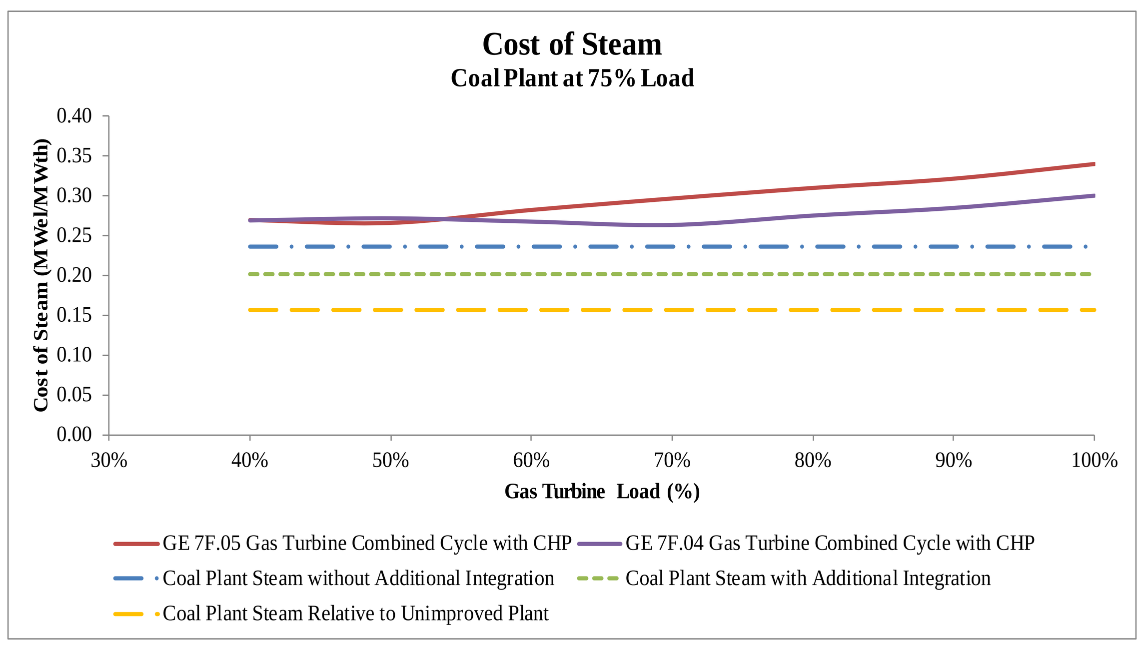

Figure 3. Cost of steam from various sources with coal plant at 75% load

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.

References

[1] Hoffmann JW, Hackett GA, Lewis EG, Chou VH. Derate Mitigation Options for Pulverized Coal Power Plant Carbon Capture Retrofits. Energy Procedia 114 (2017) 6465 – 6477