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COGENERATION FOR CO_2 REDUCTION AND POLYGENERATION FOR CO_2 SEQUESTRATION

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by

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ABSTRACT

At the 1998 Forth International Conference on Greenhouse Gas Control Technology (GHGT-4) SFA Pacific presented a paper entitled *A Portfolio Selection Approach for Power Plant CO_2 Capture, Separation and R&D Options* [1]. That original paper presented an ongoing analysis of the relative costs for CO_2 mitigation by various options in new power plants. Numerous configurations and options were developed for various fuels. Both commercial and advanced technologies for power generation, as well as various CO_2 capture and separation options, were analyzed. Each option was summarized in a single-page spreadsheet that included mass and energy balance plus capital cost and economics. That paper has received widespread review because this approach facilitates transparent and consistent analysis for objective identification of innovative options and R&D opportunities that could significantly reduce the cost of CO_2 capture and separation.

In the three years since the GHGT-4 paper, there have been numerous additional cases and improvements to this ongoing analysis of various power plant CO_2 mitigation options. Presented at this conference in another paper entitled *CO2 Mitigation Economics for Existing Coal-fired Power Plants* is SFA Pacific's analysis of retrofits to existing power plants [2]. Cogeneration and polygeneration are the subjects analyzed in this paper. These two options are becoming increasingly important due to the ongoing worldwide deregulation of electric power generation. Cogeneration increases efficiency thereby reducing CO_2 emissions whereas polygeneration is an interesting option for low cost CO_2 sequestration.

BACKGROUND

Cogeneration refers to the generation of combined heat and power (CHP). It usually involves combined electricity and steam generation, which is more efficient than a central power plant generating only electricity that requires large coolers to condense steam. Cogeneration has been limited, however, due to various reasons, including regulated electric utilities resistance, inadequate cogen "heat hosts," and the use of cogeneration technology that results in a low power-to-cogen heat ratio.

A fundamental change in electric power generation began in the United States in 1978 with the Public Utility Regulatory Policy Act (PURPA). This law was enacted to promote efficiency by requiring regulated electric utilities to purchase cogenerated electricity from non-utility cogenerators at the utility's "avoided cost." The original PURPA had some inequities due to the definition of avoided cost, qualification of projects with only "token" cogeneration, and the requirement to purchase all "qualified facility" (QF) power, without dispatch limits, even if the utility already had large amounts of excess capacity. Nevertheless, the overwhelming success of PURPA led to more broad-based deregulation of power generation in the United States in the early 1990s. In just the last 15 years, non-utility generators have grown from near zero to over 91,000 MW or 12% of the entire U.S. installed power generation capacity. Most electric utilities have set up non-regulated subsidiaries to build independent power plants (IPP) in other regions and nations. Australia, Canada, England, The Netherlands and Scandinavia followed the United States' lead in deregulating power generation. Furthermore, this trend toward deregulating power generation continues worldwide.

Specifically, deregulation has helped Europe become the world leader in cogeneration. Cogeneration now supplies 14% of Europe's power, and cogeneration power is projected to increase to 30% by 2010. The Netherlands projects over 60% of its power from cogeneration by 2010. About half of the proposed industrial cogeneration capacity in The Netherlands is being delayed so existing central power plants can continue to operate to the end of their economic life. During this time, The Netherlands continues to encourage less economical small cogeneration systems (distributed generations) as these have little impact on the total generation capacity.

Cogeneration now supplies about 10% of the electricity in the United States. Additional U.S. cogeneration is being delayed due to slow state-by-state deregulation and the life extension of a significant capacity (about 300,000 MW) of existing baseload utility coal and nuclear power plants. Most of the current requirements for additional power generation capacity in the United States are for peaking and cycling power that is less economically attractive for cogeneration.

Deregulation has also impacted the choice of cogeneration technology. Once cogeneration power can be sold to the grid at a fair market price, there is a major advantage in using gas turbines. This is because compared to a steam turbine system, gas turbine-based cogeneration produces 3-5 times more power in "true" cogeneration (where no steam goes to barometric condensers cooling). Since cogeneration is "heat host" limited the use of gas turbines significantly increases the power potential for cogeneration.

Gas turbine cogeneration is predominately based on natural gas. However, deregulation has also helped gas turbine cogeneration that is based on gasification. A recent worldwide survey of commercial gasification projects has shown a large increase in oil refinery-based gasification projects for "polygeneration" [3]. A number of these new refinery gasification projects have no subsidies and are developed on their own economic merit. These projects usually involve conversion of low value refinery "opportunity fuels" or wastes, such as pitch or petroleum coke, into clean synthesis gas (H_2 & CO) via gasification. This "syngas" is then utilized for various high-value refinery applications such as hydrogen for hydrotreating and syngas-based chemicals as well as firing gas turbines for cogen power and steam. Power sales to the grid is essential since it allows a large economy of scale which is generally required to make gasification economically competitive with natural gas. Other drivers include the declining markets for low quality refinery residues, stringent emission mandates and rising natural gas prices. The capital intensive gasification system is operated at high annual capacity and steady state conditions with production of the various products (syngas/hydrogen, cogen power, and cogen steam) as warranted by prices and demand. As a result, polygeneration offers efficiency, flexibility, annual load factor, and revenue advantages over central power plants. Polygeneration also matches the convergence of gas, electric, and oil industries into the deregulated energy companies of the future.

ECONOMIC BASIS FOR COGENERATION CO_2 EMISSION AVOIDANCE COST

Calculating the cost of CO_2 emissions avoidance by cogeneration first requires baseline CO_2 emissions and a baseline cost for the alternative of both a power plant and a steam boiler. **Table 1** includes heat and material balances plus capital and product costs for a "state-of-the-art" "H-class" natural gas combined cycle (NGCC) central power plant and a natural gas-fired industrial boiler. The NGCC is 400 MWe which is consistent with the previous analysis of new power plants with CO_2 sequestration presented at GHGT-4 [1]. The industrial boiler steam generation was set at 342 MWt to match the heat recovery steam generator (HRSG) in the NGCC case. This HRSG energy is equivalent to 650 metric tons of medium pressure steam in the cogeneration case. The power to steam ratio is 0.964 MWe/MWt (LHV) or 615 kWe per metric tons per hour cogen steam. This size and type cogen fits a large industrial chemical complex or oil refinery.

Highlighted by shading in **Table 1** are essential outputs used in the cogeneration analysis, including:

- Total overall thermal efficiency of the both the NGCC power and industrial natural gas fired boiler steam generation combined to 63% on a high heating value (HHV) basic. Use of low heating values (LHV) would shows a higher efficiency of 70%, however, HHV is a better reference because natural gas is normally purchased on a HHV basic.
- Capital cost estimates of the NGCC at $176 million or unit cost of $440/kW and industrial NG boiler capital of $27 million or a unit cost of $19/pound per hour steam. Therefore, the total capital of both systems is $203 million.
- Estimated cost of the electricity at $94 million per year or unit price of $35.7/MWh and steam at $39 million per year or a unit price of $4.16 per 1,000 pounds. Therefore, the total annual revenues of both systems are $133 million. This includes a capital charge rate of

20% of capital per year and a natural gas price of $3 per million Btu HHV. Higher natural gas prices improve the economic advantages of cogeneration due to its higher efficiency.

- Annual CO_2 emissions of 0.867 million metric tons for power and 0.510 million metric tons for steam generation. Therefore, the total of both of the systems is 1.377 million metric tons of CO_2 per year.

Space limitations did not permit showing the additional spreadsheets that were also developed for a smaller natural gas-based cogeneration plant and a larger coal-based polygeneration plant.

The small natural gas cogeneration plant is based on a reciprocation engine generating 1.0 MWe and 1.0 MWt (LHV) of hot or cold water for space heating/cooling. The baseline uses a natural gas fired hot water heater with bromine absorption refrigeration for cooling. This size and type of cogen fits commercial applications such as shopping centers, offices, hotels and large apartment complexes. The reciprocating engine is used because of its high power to heat ratio and its good part-load performance. Low annual load factors are a fundamental problem for small cogeneration systems. However, power sales to the grid at a fair market price helps reduces this problem.

The large coal-based polygeneration system is based on coal gasification to generate: 400 MWe power, 400 MWt (LHV) or 800 metric tons per hour steam, and a 400 MWt (LHV) or 1,732 metric tons per day methanol plant. Methanol was selected because of the successful development of the liquid slurry phase methanol reactor operated with syngas for coal gasification. This is now in commercial operation at the Tennessee Eastman chemical complex in Kingsport, Tennessee. It was developed by Air Products and Chemicals with demonstration cost sharing support from Tennessee Eastman and the U.S. DOE Clean Coal Technology (CCT) program (see www.fe.doe.gov for details). The original Texaco based coal gasification plant was built with no subsidies in the 1980s. The liquid slurry phase reactor is significant for gasification polygeneration because it allows feeding un-shifted CO-rich syngas to a once-through syngas reactor while the unconverted tail gas can be directly fed to the gas turbine. Liquid slurry phase reactors making DME or F-T can also do insitu CO shifting to H_2 with the F-T reaction byproduct H_2O formation to significantly improve once-through yields of feeding CO-rich syngas.

RESULTS

Table 2 is the single-page spreadsheet for the NGCC cogeneration. This type of spreadsheet is developed for each CO_2 reduction or recovery option. Cogeneration impacts the HRSG and the steam turbine relative to the NGCC baseline power plant in **Table 1**. High-pressure steam is superheated in the HRSG and then extracted from the steam turbine/generator as 10 bar medium pressure steam. Avoiding steam reheat slightly reduces the unit capital cost of the HRSG and steam turbine, but increases the mass of steam generated. The steam turbine/generator is over-designed for flexibility to condense all the steam. This about doubled the capital cost of the steam turbine/generator. A slightly larger capacity was assumed for the gas turbine in the cogeneration case to maintain the identical net energy productions as in **Table 1**. This was done to keep the comparison and economic analysis as simple as possible.

Highlighted by shading in **Table 2** are essential outputs use in the cogeneration analysis that directly compare to those in **Table 1**. The total investment, annual costs, and CO_2 emissions are all less for the cogeneration compared to the equivalent central power plant and steam boiler. This means there is no net cost for CO_2 reduction or avoidance relative to the baseline as costs and annual CO_2 emissions are both reduced by cogeneration. The net cost of electricity has also declined from $35.7 to $31.1 per MWh when a credit is taken for the cogen steam at only 75% of the steam cost determined in **Table 1.**

The smaller natural gas-based reciprocating engine cogeneration and the larger coal-based gasification polygeneration systems both show the same results—reduced costs and reduced CO_2 emissions. However, the baseline assumptions for these two options are more debatable. It can be argued that the baseline for the small natural gas energy systems could be power from a large new NGCC and the heating/cooling from a lower capital cost electric heat pump. It can also be argued that the baseline for the large coal energy system could be all three energy products (power, steam, and methanol) from lower capital cost and CO_2 emissions natural gas based processes. However, the “all” natural gas idea is unrealistic due to the fact over 50 % of the annual electric power generation in the United States is currently from coal. The energy content of that coal is over 19 quadrillion Btu/yr. There is neither enough natural gas available nor the delivery infrastructure in place to replace all this coal. Natural gas energy price is also 3-5 times that of coal.

CONCLUSIONS AND DISCUSSION

Cogeneration and polygeneration have unique advantages for reducing CO_2 emissions in electric power generation. These technologies increase electricity supplies while reducing both costs and CO_2 emissions. The essential issue is deregulation of electric power generation so large amounts of cogeneration-based electricity can be sold to the grid at fair market prices. Secondary issues are locating large cogeneration “heat hosts” and using technologies with high power to heat ratio.

A 1991 study by The Japan Gas Association addressed the market potential for cogeneration in Japan. This study considered only existing industrial boilers in Japan. The study assumed repowering with gas turbines sized so the associated HRSGs matched the replaced steam boiler capacity. The power generation potential was estimated at 17,500 MWe. Relative to existing Japanese power generation they estimated 16% energy saving with an annual CO_2 reduction of 50 million metric tons per year.

New technologies and innovative cogeneration applications also increase the market potential for cogeneration and polygeneration. For example, the development of intercooled and recuperated gas turbines could double the power to cogen heat ratio relative to existing gas turbines. Another example is innovative process industry cogeneration. The largest single heat requirement for an oil refinery is the crude oil furnace, consuming about 1% of the energy equivalent of the refinery crude oil feed. If all the oil refineries in the world used gas turbines for power generation and modified HRSG-type systems to heat the crude oil, we estimate the power generation potential to be 135,000 MWe. Several variations of this concept are already being commercially utilized in European oil refineries.

Finally and perhaps most importantly, gasification polygeneration projects have the unique potential for low cost CO_2 sequestration [4]. For example, the commercial gasification polygeneration project currently operating in the Shell Oil refinery in Pernis, The Netherlands, vents about 1 million metric tons per year of relatively pure and dry CO_2. Therefore, the incremental cost of recovering this pure CO_2 stream is relatively low, requiring only CO_2 compressors, pipeline, storage and utilization. Shell Oil will soon recover and utilize a portion of the Pernis CO_2 stream for use in greenhouses. This will reduce the current practice of burning natural gas to supply the higher CO_2 levels in greenhouses. The economics of this project still require government support. Nevertheless, polygeneration could emerge as the key technology for both CO_2 reduction and CO_2 sequestration. This is important because cogeneration and other efficiency improvements generally only reduce the growth rate of CO_2 emissions. Polygeneration has the unique potential to significantly reduce the cost of CO_2 sequestration. Larger potential exists for additional CO_2 utilization in enhanced oil recovery (EOR) and enhanced coal bed methane (CBM) recovery. However, market incentives for CO_2 sequestration ultimately become essential for any significant reductions in CO_2.

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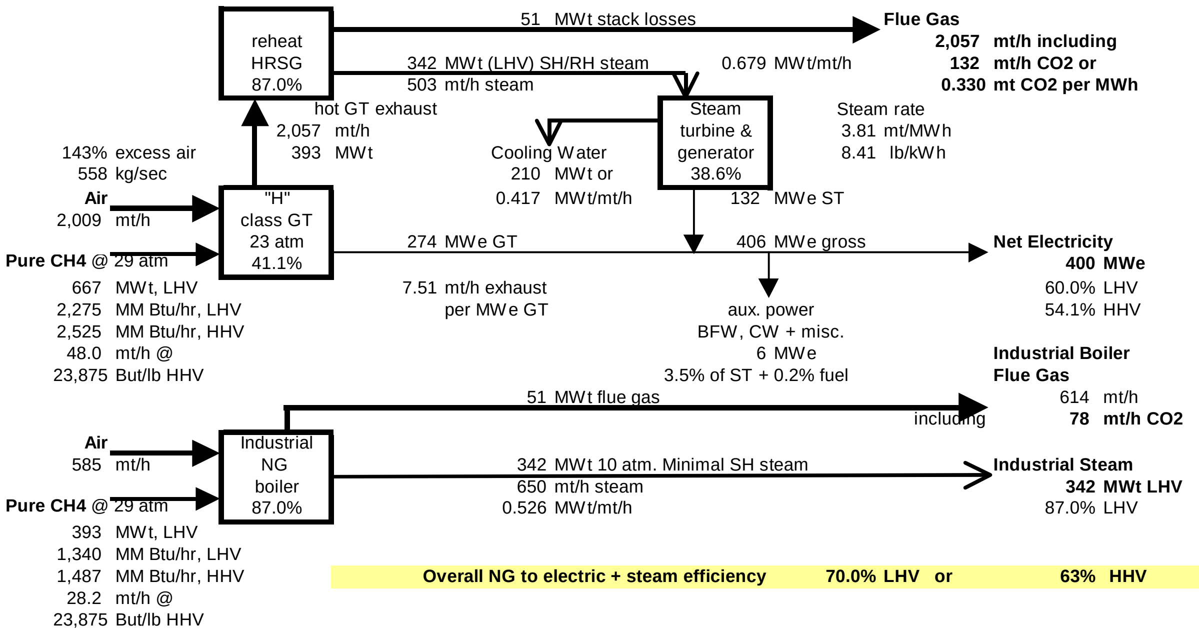
Table 1
Baseline NGCC Power Plant plus Industrial Boilers

(Reference for NGCC cogen CO2 avoidance)
June 2000 draft version

Basis: ISO conditions of 15°C, low heating value (**LHV**) with once-through cooling water
400 MWe net via "state of the art" (1,425°C & 23 atm.) "H" class GT based CC



Overall NG to electric + steam efficiency — 70.0% LHV or 63% HHV

Capital Costs - Power Plant	**key unit costs**		**$ MM**	**$/kW** net	**Notes**
GT/gen	280	$/kWe GT gross	77	192	
HRSG boiler	85	$/kWt SH/RH steam	29	73	26 $/lb/hr SH/RH steam
ST/gen, BFW & CW	225	$/kWe ST gross	30	74	reheat condensing
	Process units subtotal		135	339	
General facilities	20%	of process units	27	68	
Eng. & contingencies	10%	of process units	14	34	
		NGCC capital cost	**176**	**440**	net electric

Incremental costs of GT to CC	**$ MM**	**$/kW**	**MWe** net
just GT topping cycle	100	**365**	273
added HRSG & ST steam cycle	76	**602**	127
Total	176	440	400

Capital Costs - Ind. Boiler	**key unit costs**		**$ MM**	**$/Kg/h**	$/lb/h	
NG package boiler	60	$/kWt low SH steam	20	32	14	medium press. Steam
General facilities	20%	of process units	4	6	3	
Eng. & contingencies	10%	of process units	2	3	1	
		Ind. Steam capital	**27**	**41**	**19**	

Total power and steam capital costs — 203

Electricity Cost	**Inputs for summary**				
	75% ann. capacity factor		**$ MM/yr**	**$/MWh**	
Capital charges		20% of capital per yr	35	13.4	
All non-fuel O&M		5% of capital per yr	9	3.4	**NGCC Power Plant**
CO2 emission tax	$	- per mt CO2	-	-	**CO2 emissions**
Natural gas	$	3.33 per MM Btu LHV	50	19.0	**to atmosphere**
		Electricity cost	**94**	**35.7**	**0.867 MM mt/yr**

Industrial Steam Cost	**Inputs for summary**					
	75% ann. capacity factor		**$ MM/yr**	**$/mt**	**$/M lb**	
Capital charges		20% of capital per yr	5	1.2	0.57	
All non-fuel O&M		5% of capital per yr	1	0.3	0.14	**Industrial Boiler**
CO2 emission tax	$	- per mt CO2	-	-	-	**CO2 emissions**
Natural gas	$	3.33 per MM Btu LHV	33	7.6	3.46	**to atmosphere**
		Steam Cost used in Table 2 for cogen steam credits	**39**	**9.2**	**4.16**	**0.510** MM mt/yr

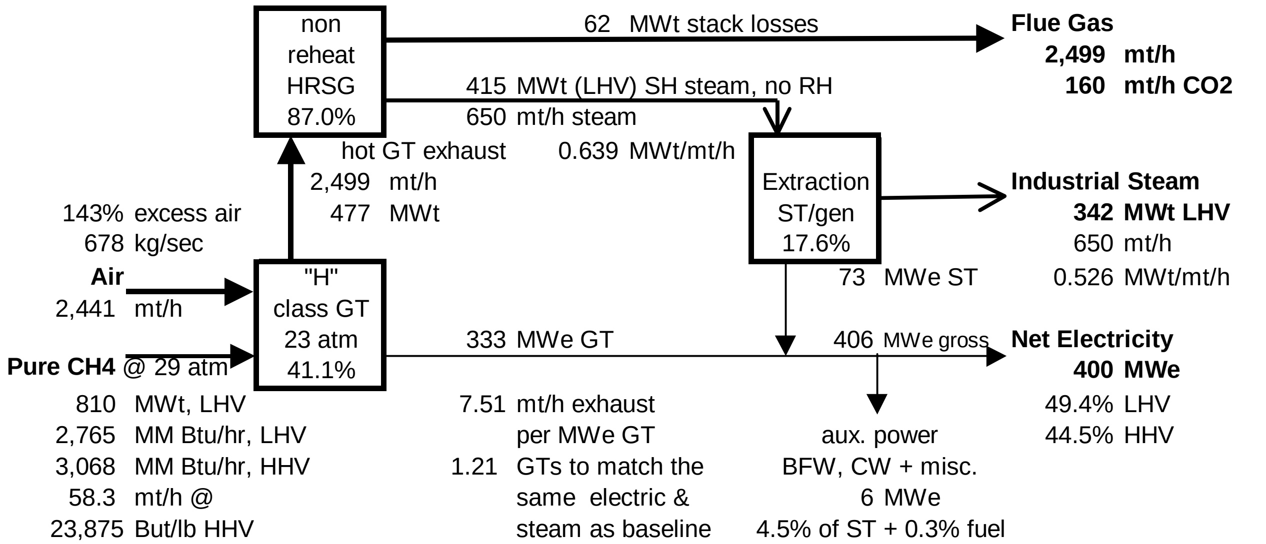
Baseline NGCC Power & Ind. Steam totals	**133 $MM/yr** **Total revenues required**	**1.377 MM mt/yr CO2**

Source: SFA Pacific, Inc.

Table 2
NGCC Cogen Power plus Industrial Steam

(Reference for NGCC cogen CO2 avoidance)
June 2000 draft version

Basis: ISO conditions of 15°C, low heating value (**LHV**)
400 MWe net via "state of the art" (1,425°C & 23 atm.) "H" class GT based CC
Assumed increased capacity of the same GT to maintain 400 MWe in cogen for comparison only



	Overall NG to electric + steam efficiency			**91.6% LHV or**	**82.6% HHV**

Capital Costs Cogen	**key unit costs**		**$ MM**	only power **$/kW**	**Notes**
GT/gen	280	$/kWe GT gross	93	233	
HRSG boiler	80	$/kWt SH steam	33	83	23 $/lb/hr non RH steam
ST/gen, BFW & CW	200	$/kWe ST @ 146 MWe	29	73	sized for condensing/non-reheat
	Process units subtotal		156	389	& MP steam expraction for cogen
General facilities	20%	of process units	31	78	
Eng. & contingencies	10%	of process units	16	39	
		Total capital cost	**202**	**506**	net electricity only

Electricity Cost with steam credits	**Inputs for summary**		**$ MM/yr**	only power **$/MWh**		
	75%	ann. capacity factor				
Capital charges	20%	of capital per yr	40	15.4		
All non-fuel O&M	5%	of capital per yr	10	3.8		
CO2 emission tax	$ -	per mt CO2	-	-		
Natural gas	$ 3.33	per MM Btu LHV	61	23.0		
Cogen steam credits	**(6.9)**	$/mt MP steam @ only			$ MM/y	**Cogen CO2 emissions**
for net power cost	**75%**	of Table 1 steam cost		**(11.2)**	**(29)**	**to atmosphere**
		NG Cogen power & steam	**111**	**31.1**		**1.053 MM mt/yr**
Baseline Separate NGCC power & Steam reference			**133**			**1.377**
		net change	**-22**	**$ MM/yr**		**-0.324 MM mt/yr**
NG Cogen power & steam		**relative to baseline**	**84%**			**76%**
		of separate NGCC & NG steam				**-68 $/mt CO2 avoided**
						-18 $/mt Carbon

Source: SFA Pacific, Inc.