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Chapter 9
Cofiring Biomass and Natural Gas – Boosting Power Production from Sugarcane Residues

Arnaldo Walter, Mônica R. Souza[1] and André Faaij

9.1. WHY COFIRING?

The term cofiring has been often applied to designate the combined use of fuels in power plants as well as in industrial steam boilers. A special case is the combined use of biomass and fossil fuels, the most acknowledged idea being the mix of biomass and coal in power plants. In some countries, such as the United States, The Netherlands, Austria and Finland, cofiring biomass and fossil fuel has been commercially practiced for power production since the mid-1990s.

Environmental issues, mainly those concerned with mitigation of airborne emissions (carbon dioxide and other gaseous pollutants, especially sulfur oxides), are the main reasons for pursuing efforts on cofiring. Owing to substantial reduction of technical and economic risks, cofiring has also been considered as the first step in enhancing biomass utilization for power generation in some countries. With cofiring, for instance, it is possible to take advantage of the relatively high efficiency of large coal boilers without incurring a large investment (Sondreal et al., 2001).

Cofiring biomass and natural gas has been considered to a less extent so far, and no significant commercial experience has been identified. Recently, a report on cofiring biomass-derived fuels and natural gas in gas turbines has been released in The Netherlands (De Kant and Bodegom, 2000). The research has focused on the technical feasibility and the potential of cofiring low-heating-content fuels and natural gas over different power configurations. Gas turbine constraints and required adaptations have been inventoried with the gas turbine suppliers. Likewise, a similar study was developed some years ago at the National Renewable Energy Laboratory – NREL in the United States, but only a preliminary analysis of technical options was conducted at that time (Spath, 1995).

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Considering the biomass use, the term cofiring has been applied in a widespread sense. Strictly, cofiring corresponds to burning a mix of fuels in the same thermal device. However, cofiring has also been understood as: (i) biomass or fossil fuel use to complement the main fuel supply; (ii) biomass use to increase plant capacity, burning fuels without mixing; and even (iii) when biomass is used to full substitution of a fossil fuel in an existing power plant.

This chapter describes a research focused on opportunities for developing power production from sugarcane residues (sugarcane bagasse and sugarcane trash, i.e. leaves and tops of the plant) based on cofiring with natural gas. The three technical alternatives presented are based on the wide definition of cofiring mentioned earlier.

9.2. THE RATIONALE

Brazil is the largest producer of sugarcane in the world. The production in the harvest season of 2000–2001 reached 252 million tons, but it was as large as 315 million tons in the harvest season of 1999–2000. In that period, the amount of bagasse available at the sugar mills reached 780 PJ. Bagasse is inefficiently consumed in the cogeneration systems of sugarcane mills, generating steam that is first used to produce power and, subsequently, to fulfil process thermal demand. In addition, a small amount of the bagasse is traded and used as fuel by other industrial branches, but these market opportunities are constrained by transport costs and the low prices of fuel oil. In addition, this market tends to be further reduced, as natural gas is made available.

Tops and leaves of the sugarcane plant – the so-called sugarcane trash – are currently burned in the field before manual harvesting. Since this practice will be gradually reduced in the next 10–12 years for environmental reasons, it is predicted that the availability of sugarcane residues in Brazil will steadily increase. Sugarcane trash shall be recovered from the fields through mechanic harvesting, a technology that has been introduced in Brazil in the last few years. Potentially the availability of sugarcane trash is as large as bagasse, but topographic constraints will determine how much is economically recoverable (see also Braunbeck et al., Chapter 6).

Based on opportunity costs for sugarcane bagasse and on predicted costs for sugarcane trash recovery, it is foreseen that the cost of this biomass would be lower than 2 US$/GJ and, in some cases, even lower than 1 US$/GJ. Despite the focus given to sugarcane residues in this study, a wide range of biomass could obviously be used for the purpose of cofiring, such as wood chips, bark, thinnings, sawdust, various agriculture residues, etc.

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In Brazil, the installed electricity generation capacity is largely based on hydropower. It is estimated that almost 80 per cent of the current capacity (slightly larger than 85 GW) corresponds to hydropower plants. Clearly this enormous dependency on just one energy source is risky and a diversification of power sources is advisable. In fact, in 2001, due to lack of investments in power generation and to a drier summer than usual, power shortages have occurred. Power production from biomass provides both an opportunity for diversification and for expanding the use of renewables in the Brazilian matrix.

Natural gas power plants shall be built in Brazil in the next 5 to 10 years, fostered by governmental policies. Brazilian natural gas reserves are small but the supply is enlarged through imports from Bolivia and, possibly, from Argentina in the near future. As the natural gas market is not yet well developed, thermal power plants have been considered necessary to assure the feasibility of pipeline projects. This would allow the consumption of a large amount of natural gas during the early years of a ''take-or-pay'' contract.

Additionally, it is important to bear the perspective of private developers in mind, the main investors after privatization and deregulation of the electricity sector. Natural gas thermal power plants appear to be the main option of investment due to the short construction time of the plants, relatively low capital costs ($/kW installed), high efficiency, and large availability. On the other hand, investors identify a risky picture due to the necessity of bulk imports of natural gas and the instability of the Brazilian economy. Medium- to long-term fluctuations of natural gas prices are obviously a matter of concern for investors. The combined use of natural gas with biomass can reduce these risks and increase the fuel flexibility of new power generation capacity. This point is especially relevant in a natural gas market that is still under development.

Two additional points should be observed concerning the natural gas supply. First, the brand new Bolivia–Brazil pipeline crosses – or is relatively close to – the region where approximately 60 to 65 per cent of the Brazilian sugarcane production takes place. Second, as the natural gas market is further developed, and better opportunities for natural gas consumption arise – for instance, on premium markets such as the residential and industrial sectors – biomass could replace natural gas on thermoelectric power plants that shall be built during the early years of the pipeline operation. The period required for the development of a new natural gas market is around ten years.

Competitiveness of electricity production from biomass will strongly depend on the development of new conversion technologies and on the scale of power plants. Future power production from biomass could be based on gasification, for example. Gas turbines are power devices that have some important attributes: reasonable

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thermal efficiency and initial capital costs that are not as affected by scale effects. It is expected that, with the not-yet-commercially-available BIG-CC cycles (Biomass Gasification Integrated to Combined Cycles), the efficiency of electricity production could reach about 35 to 45 per cent (Walter et al., 2000).

Performance penalties associated with gas turbine adaptation to gasified biomass are meaningful. Biomass-derived gas from air-blown gasifiers has only about 8 to 10 per cent of the energy content of natural gas, resulting in larger mass flow through gas turbines. As a consequence, technical problems can occur, such as compressor surge, increased thermal and mechanical loads on compressor airfoils, the need of an adapted combustion/injection system and problems with flame stability (Rodrigues et al., 2003a). Regarding the BIG-CC technology, cofiring with natural gas is here mainly proposed as a short-term approach to cope with penalties on both efficiency and power resulting from gas turbine derating. The expansion of power plant capacities due to cofiring is also an important contribution for the competitiveness of electricity production from biomass (Rodrigues et al., 2003b).

However, the BIG-CC is not the only technical option for cofired biomass and natural gas plants. Commercial and proven technologies could be used as well. For instance, biomass could be fired independently from natural gas, producing steam in conventional boilers. In addition, steam production would be complemented from HRSGs – heat recovery steam generators – and both streams could be mixed to feed steam turbines of combined cycles. Furthermore, from strategic and economic points of view, electricity production from cofiring natural gas and biomass could be effectively developed as an alternative for the reduction of GHG emissions.

9.3. CASES AND HYPOTHESES FOR SIMULATION

Three cofiring alternatives are analyzed in this study. Case A corresponds to the full displacement of natural gas for biomass in combined cycle power plants. Case B concerns a partial use of biomass, complementing natural gas in combined cycle power plants. Finally, Case C regards the use of biomass only to increase steam production, which is then used in the bottoming cycle (Rankine cycle) of a combined cycle.

All results presented here are based on computational simulations. For the purpose of simulation, some characteristics of the GE PG6101(FA) (a machine developed to operate continuously with low-heating-value fuel) were considered. Only one complementary result regarding Case B is based on GE Frame 7 class gas turbines, for which some characteristics of the GE PG9171(E) were taken.

The BIG-CC system considered in Cases A and B is based on an atmospheric air-blown gasifier. The gasification technology taken into account here – as well as the

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subsequent low-pressure gas cleaning system – is similar to that proposed by the Swedish company TPS (Termiska Processer AB). Some of the biomass projects that are aimed at the provision of electricity and are under development at present are based on atmospheric gasification technology. BIG-CC systems based on pressurized gasification are also an alternative and possibly would be more feasible for the range of capacities considered here. Atmospheric systems will probably present a lower biomass to electricity conversion efficiency but, on the other hand, in the short term, fewer problems can be expected with syngas production and its cleanup.

BIG-GT technology (generally speaking, gas turbine cycles integrated to biomass gasification) is still under development. The main technological issues in the demonstration of BIG-GT are concerned with (i) scaling-up the gasifier and gas-cleaning technologies and (ii) gas turbine adaptation to low-heating-content fuel. However, the main problems with the current demonstration projects seem to be the initial costs of first generation plants and the difficulties of arranging a reliable fuel supply for the lifetime of the project at a reasonable cost (Walter et al., 2000).

The simulation of BIG-CC systems is based on the schemes and hypothesis presented by Consonni and Larson (1996). Design conditions considered for the bagasse drying result in a moisture content of 15 per cent by weight at the gasifier entrance, the gas being used for drying is the HRSG flue gas. Gasification takes place with air injection, and the syngas leaves the gasifier at about 870°C.

Raw syngas composition was evaluated based on previous results of gasifier simulation performed by ASPEN® – Advanced System for Process Engineering (Walter et al., 1998b). As proxy, it was considered that sugarcane trash has the same ultimate analysis as of bagasse. Bagasse and syngas compositions (raw and clean) considered in this study are presented in Table 9.1.

A code was used to evaluate gas turbine off-design performance, i.e. the gas turbine operation with syngas. Details of the procedure can be seen in Walter et al. (1998a). To avoid very high compressor pressure ratio that could dangerously reduce compressor surge margin, gas turbine derating was considered. The rise of pressure ratio under certain limits can be eventually accepted for the compressor of some industrial gas turbines (Corman and Todd, 1993) but, in general, high-pressure ratio imposes unacceptable problems concerned with the increase of shaft torque and thermal loads on airfoils, making this option very aggressive to the equipment (Johnson, 1990). For syngas burning, it was assumed that the maximum GT compressor pressure ratio is 16.4, while its nominal pressure ratio at ISO basis is 14.9.

A common way to derate gas turbines, i.e. to reduce their output power, is through the reduction of the maximum temperature, which is accomplished with the reduction of fuel flow. The term derating is used here to indicate a strategy for gas turbine control to avoid machine operation with a high pressure ratio. In fact,

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Table 9.1. Biomass and syngas composition

Biomass composition		Syngas composition	
Bagasse (and trash) ultimate analysis	% Weight – dry basis	Component	Clean % Molecular weight
Carbon	46.3	H_2	16.69
Oxygen	43.3	CO	19.98
Hydrogen	6.4	CO_2	10.49
Nitrogen		CH_4	2.63
Sulfur	<0.1	C_6H_6	0.33
Ash	4.0	H_2O	3.24
LHV[1] [MJ/kg]	17.5	N_2	46.64
(Dry basis)		NH_3	Negligible[2]
LHV [MJ/kg]	7.84	Tar	Negligible
(50% moisture)		LHV [MJ/kg]	5.16

[1] LHV = Lower heating value.
[2] Ammonia and tar should be completely eliminate on the clean-up process.

gas turbine derating is one of the possible strategies that would allow machine conversion from natural gas to syngas. Other strategies are (i) reducing compressor air flow through control of inlet guide vanes – IGVs, (ii) enlarging the expander cross-sectional area in a permanent change, and (iii) promoting blast-air extraction after the compressor. From the viewpoint of the whole system performance, and consequently from the viewpoint of electricity generating costs, derating is the worst solution (Rodrigues et al., 2003a). However, owing to its simplicity, for the first generation of BIG-CC systems, this is most probably the way gas turbines would be converted to syngas firing.

To simplify the modeling procedure, it was considered that steam is produced in an unfired HRSG at just one pressure level, without reheating. This is a reasonable hypothesis for stand-alone BIG-CC cycles due to the requirement of a minimum temperature for HRSG exhaust gases (Consoni and Larson, 1996), but it is not the case for combined cycles burning natural gas. Indeed, it is well known that high efficiency combined cycles require two or three steam pressure levels besides reheating (Bathie, 1996). For instance, for the combined cycle based on PG6101(FA), when natural gas is burned, three steam pressure levels and reheating at the intermediate pressure level is recommended. It is considered that the steam pressure at the turbine entrance is 100 bar. Steam temperature is a function of the GT exhaust gases temperature, while the maximum steam temperature was assumed to be 538°C. Steam is extracted from the steam turbine at 0.48 MPa to feed the deaerator, while the remaining flow is condensed at 9.6 kPa. The temperature of the HRSG feed water is assumed to be constant in all the simulated cases (120°C).

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Table 9.2. Case A – Simulation results for natural gas and syngas

Parameter	NG	Syngas
Gas turbine		
GT power [MW]	67	77.5
Pressure ratio	14.9	16.4
Firing temperature [°C]	1288	1178.8
Fuel consumption [kg/s]	4.3	38
Thermal efficiency [%]	32.8	34.7
Steam cycle		
Steam cycle power [MW]	28	31.7
Steam pressure [bar]	100	100
Steam temperature [°C]	538	510.5
CC net power [MW]	94	87
CC net efficiency [%]	46	39[1]

[1] Value corresponds to the overall biomass-to-electricity efficiency.

9.4. SIMULATION AND FEASIBILITY RESULTS

9.4.1. Case A

Simulation results considering combined cycle operation using only natural gas or biomass-derived gas are presented in Table 9.2. A detailed information about this alternative can be found in Walter et al. (1998b). These simulation results correspond to combined cycle operations under the ISO basis. As can be seen, despite derating, the thermal efficiency of a gas turbine operating with syngas is higher than with natural gas, owing to the increase on gas mass flow and to the higher GT compressor pressure ratio. With syngas firing, more power is also produced by the steam bottoming cycle due to the increase of GT exhaust gas flow, but steam is produced at a lower temperature (lower exhaust gas temperature). Albeit more power production both at the gas turbine and at the steam cycle, the system net power is lower when syngas is burned due to high power consumption of plant auxiliaries (mainly the syngas compressor). As mentioned before, the simulation results for natural gas combined cycle are not optimized as it is considered that steam is generated at just one pressure level at the HRSG. A single combined cycle unit (one gas turbine, one HRSG and one steam turbine) of the same capacity can operate with efficiency as high as 53 per cent (Gas Turbine World, 2000).

For current commercial natural gas combined cycles (NG-CC), data of unit capital costs were taken from the literature (Gas Turbine World, 2000). The turnkey unit capital cost of a combined cycle based on PG6101(FA) is estimated at 680 US$/kW. The levelized electricity generating cost was calculated considering the following assumptions: 30-year life, 12 per cent real pretax discount rate, capacity factor 0.85,

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O&M (operation and maintenance) costs at 0.4 cents/kWh, and natural gas cost equivalent to 2.5 $/MMBTU. All costs in this study are presented in 1999 US$.

For BIG-CC systems based on atmospheric air-blown gasifiers, the installed investment cost was estimated using Eq. (1). This equation is primarily based on estimates available in the literature for the first commercial plant and incorporates ''learning effects'' (progress ratio 0.80 and the 5th similar commercial unit). Estimates given by this equation are very close to the estimates presented by other authors for BIG-CC systems of the same net capacity.

$$k_{A\ IGCC} = 5612\ (MW)^{-0.2953}\ [\$/kW] \quad (1)$$

For BIG-CC systems, the nonfuel operation and maintenance cost was estimated at 8.2 US$/MWh. The average cost of biomass (bagasse and trash) was estimated at 8 US$/t. To assure a proper comparison with NG-CC results, some assumptions are common in both cases as, for instance, plant-year life, real discount rate and plant capacity factor.

Estimated levelized electricity generating costs are presented in Table 9.3. The feasibility analysis is based on the evaluation of the internal discount rate (IDR) of the investment. Besides the aforementioned assumptions, it was also considered that (i) the plant construction time is two years in all cases, and 80 per cent of the investment is made during the first year, (ii) taxes are evaluated over the net revenue (as a simplification, a 15 per cent duty was considered), and (iii) the depreciation was calculated along 10 years, using a linear model. Revenues were calculated considering that all electricity can be sold at 45 US$/MWh. Actually, this assumption does not correspond to the reality of the electricity market post deregulation since, in a competitive environment, investors need to define their prices either based on their actual generating costs or on their own profit expectation.

The cofiring case presented in Table 9.3 corresponds to the substitution of fuel, from natural gas to biomass. It was considered that the investment leading to this

Table 9.3. Case A – main results of feasibility analysis

Combined cycles	NG-CC		BIG-CC
Thermal efficiency [%]	46	53	39
Cost of electricity – COE [$/MWh]	36.8	34.1	45.0
IDR (%)	21.4	24.2	12.8
Cofiring	NG to syngas		
Thermal efficiency with NG-CC [%]	46		53
IDR (%)	15.4		16.6
IDR with carbon credit (10 $/t CO_2)	17.3		18.5
IDR with carbon credit (20 $/t CO_2)	19.0		20.2

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substitution starts after four years of operation with natural gas. After the sixth year of operation, just syngas is burned at the gas turbine. The investment required for the substitution was estimated as the difference of the installed unit capital cost for both the options.

The feasibility analysis also includes the evaluation of the impact of credits based on avoided emissions of carbon dioxide. These credits could be paid, for instance, by international funds on the context of the Clean Development Mechanism to boost projects aimed at reducing carbon dioxide emissions. It was considered that these credits are free of tax duties. Simplifying the analysis, it was also considered that sugarcane has a nil carbon balance. As can be seen in Table 9.3, each dollar earned per ton of carbon dioxide not released could imply an increment on the IDR of about 0.2 per cent. The results considered two options for the natural gas combined cycle – 46 per cent, that is the simulation result, and 53 per cent, that is the expected thermal efficiency of a single combined cycle unit based on a Frame 6(FA) gas turbine (steam produced at three pressure levels, with reheating).

9.4.2. Case B – preliminary results

The simulation results of a preliminary analysis of Case B are presented in Figure 9.1 for different rates of natural gas replacement. More details of the simulation procedure adopted are presented in Walter et al., 1999. The far left points correspond to gas turbine operation with natural gas only, while the far right points correspond to gas turbine operation just with biomass-derived gas. Gas turbine derating influences combined cycle performance. The gradual switch from natural gas to syngas, as far as GT derating is not necessary, increases power production due to (i) a larger gas

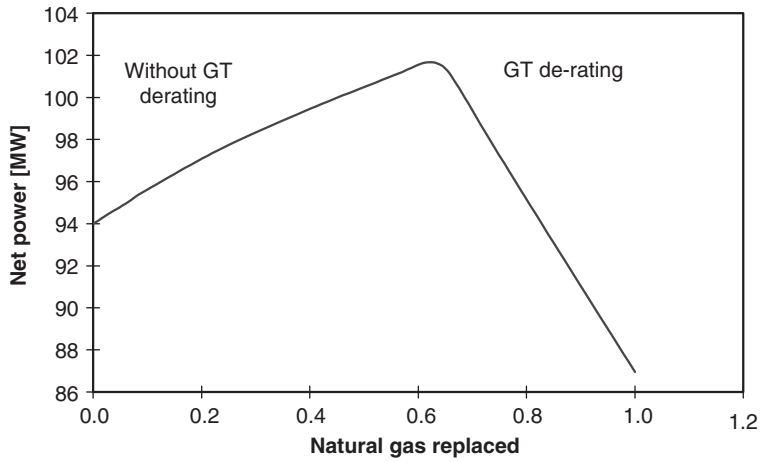

Figure 9.1. Combined cycle power production as a function of natural gas replacement (mass basis).

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mass flow and (ii) an increase in compressor pressure ratio. When a larger amount of syngas is used and GT derating is imposed, net power production drops due to derating itself and due to the increasing power consumption of auxiliaries (mainly syngas compressor and air compressor).

Based on the same economic assumptions previously presented for Case A, a feasibility analysis of partial switch from natural gas to syngas was developed. For all intermediary cases between the two limits (GT operation on natural gas and on syngas only), the installed capital cost was estimated as the cost of a conventional natural gas combined cycle plus the capital cost of a biomass gasifier and gas-cleaning unit. The additional investment on syngas production was calculated according to the amount of biomass required (as received, with 50 per cent moisture), assuming a reference value (Faaij et al., 1997) and a scaling factor of 0.70. Finally, a 1.6 factor was applied over the estimated capital cost to take into account the overall set of extra costs regarding GT adaptation and equipment installation.

The cost of electricity as a function of the share of natural gas replaced is presented in Figure 9.2. The same figure includes results that correspond to the impact of credits due to carbon dioxide abatement. As can be seen, carbon credits equivalent to 10 US$/t of CO_2 avoided could make the cofiring option feasible vis-à-vis electricity generation from natural gas in a large range of mixtures between natural gas and biomass-derived gas. At a credit price equivalent to 20 US$/t CO_2 avoided, electricity generation from cofiring natural gas and biomass is even cheaper than some conventional alternatives.

Finally, Figure 9.3 shows the evolution of investment IDR as a function of the share of natural gas replaced and carbon credits as well. The decline of IDR as far as gas turbine operation is switched from natural gas to syngas is due to the higher

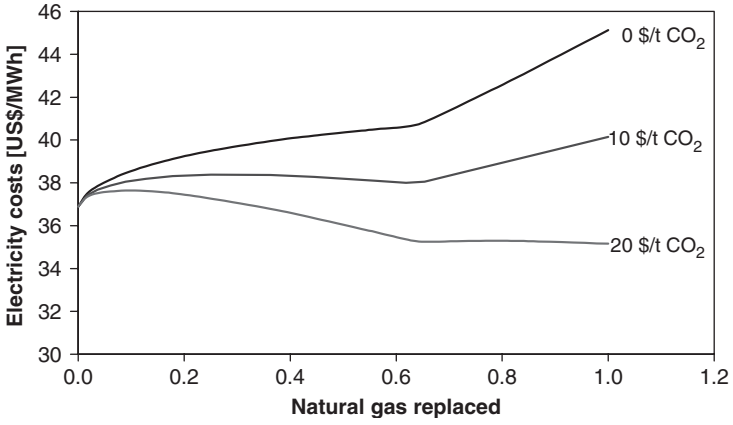

Figure 9.2. Estimated electricity costs as a function of natural gas replacement and carbon credits derived from CO_2 abatement.

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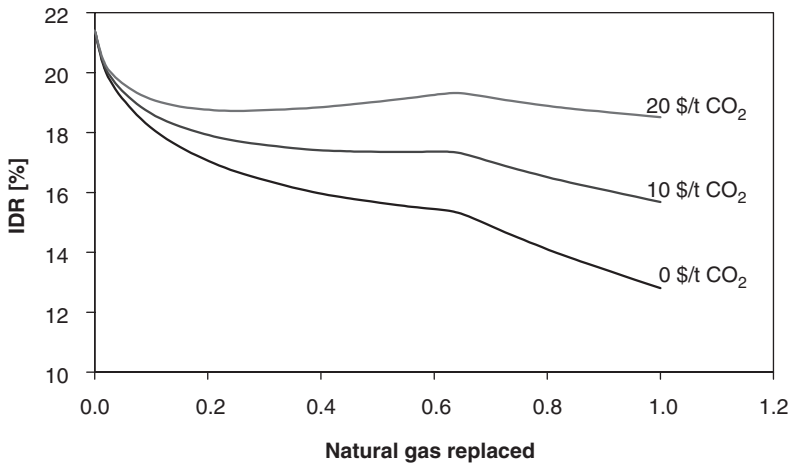

Figure 9.3. IDR as a function of the share of natural gas replaced and use of carbon credits.

cost of electricity (0 $/t CO_2). Carbons credits make IDR reduction smoother or can counterbalance this tendency at higher carbon credit prices.

9.4.3. Case C

Case C was defined considering a natural gas combined cycle plant based on two PG6101(FA) units, one unfired HRSG for each gas turbine and just one steam turbine. The total capacity of the NG-CC is 187.2 MW, with an additional contribution of 53.2 MW from biomass. Thus, the total plant capacity is 240.4 MW. The steam cycle parameters and the overall cycle performance are the same as presented in Table 9.2. The biomass contribution to the cofiring plant occurs in a conventional steam power cycle in which steam is generated at the same live-steam parameters as in the HRSGs, producing 53.2 MW as well. Main simulation results are presented in Table 9.4.

The feasibility assessment was accomplished based on the assumptions described earlier for a NG-CC power plant. The initial capital cost for a 185 MW class was estimated as 480 US$/kW. For the steam cycle plant based on biomass, the unit capital cost is estimated at 1110 US$/kW. This evaluation is based on cost functions for the main plant components and results were checked with published data. Annual operation and maintenance costs (excluding fuel) were considered as equivalent to 5 per cent of the initial capital cost.

The main results of the feasibility analysis are presented in Table 9.5. The addition of a biomass module represents an increase in the plant capacity of about 28 per cent vis-à-vis the natural gas combined cycle plant. As the cost of producing electricity through the biomass plant running all over the year (capacity factor 0.85, as well

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Table 9.4. Case C – Main simulation results

Gas turbine power [MW]	2×67
Conventional steam CC bottoming cycle [MW]	53.2
Steam cycle based on biomass [MW]	53.2
Total capacity [MW]	240.4
Natural gas consumption [kg/s]	8.6
Biomass consumption [kg/s]	25.93
NG-CC cycle efficiency [%]	46.0
Biomass plant efficiency [%]	26.2
Overall plant efficiency [%]	41.6

Table 9.5. Case C – Results of the feasibility analysis

Investment on biomass part [$/kW]	NG-CC	Co-firing 1100	Co-firing 500
Cost of electricity [$/MWh]	33.5	35.3	31.9
IDR (%)	28.7	23.3	30.9
IDR with carbon credit (10 $/t CO_2)	–	24.6	32.6
IDR with carbon credit (20 $/t CO_2)	–	25.9	34.3

as for the NG-CC) is higher than the cost estimated for electricity produced in the NG-CC plant (40.0×33.5 US$/MWh), there is a rise in the cost of electricity produced by the cofired plant.

For full-year operation of the biomass-based power plant, the IDR is significantly reduced vis-à-vis the NG-CC case. The investment would be more feasible if carbon credits were available but these should be as high as 40 $/t CO_2 to make the cost of electricity of the cofired plant equivalent to the NG-CC.

However, if the biomass-based power plant operates for a shorter period during the year (e.g. just during the 6–7 months of the sugarcane harvest season), the final cost of electricity rises. For instance, for 4080 h of operation per year (200 days of harvesting and a capacity factor of 0.85 during this period), the cost of electricity produced by the biomass power plant rises to 61.4 US$/MWh and the cost of electricity of the cofired unit increases to 37.7 US$/MWh. Simplifying the analysis, it was considered that the average biomass cost is 8 US$/t in both cases. The IDR is estimated as 19.9, 20.6 and 21.4 per cent for the three cases considered (depending on the value of the carbon credits).

The Case C was also evaluated considering a capital cost for the steam cycle plant based on biomass at 500 US$/kW. This is a reasonable estimate for equipment built in Brazil as the cost in US dollars has dropped significantly due to the devaluation of Brazilian currency since early 1999. As can be seen in Table 9.5, in this case, the cost of electricity generated in the cofired unit could be lower than in the natural gas combined cycle unit, even without carbon credits.

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9.5. COMPARISON OF ALTERNATIVES

A combined cycle plant based on a PG6101(FA) gas turbine, such as the one considered in this study, and following the hypothesis assumed, consumes about 500 thousand Nm^3/day of natural gas operating at full load basis (about 430 Nm^3/day for an average capacity factor of 0.85). Thus to guarantee full operation of a 100 MW plant, some 540 thousand Nm^3/day would be needed. Table 9.6 summarizes the amount of natural gas that can be displaced per set of 100 MW power capacity for each cofiring alternative analyzed in this study. Results for Case B correspond to the best case from the point of view of capacity, i.e. 101.7 MW of net capacity, for 61.9 per cent substitution of natural gas on mass basis.

To give a perspective of this contribution, we look into the present situation in Brazil. The Brazilian government has recently decided to support the installation of almost 17 GW of thermal power capacity, totalling 49 plants, most of them designed to fire natural gas. Of this total capacity, 6.5 GW are planned in industrialized sites of the State of São Paulo, not far from the regions where there is a large concentration of sugarcane mills. The natural gas demand to allow the operation of 6500 MW new capacity in the State of São Paulo is estimated at 25 to 26 million Nm^3/day, taking into account the predicted average annual capacity factor and actual natural gas to electricity efficiencies (in round numbers, larger than the performance figures used in this article). This natural gas volume is quite substantial as a share of the capacity of the brand new Brazil–Bolivia natural gas pipeline, the main source of natural gas supply for the years to come.

The adoption of a Case C strategy would allow a maximum displacement of natural gas of about $(124.6/577.0) \times 25$–26 million $Nm^3/day = 5.4$–5.6 million Nm^3/day. With the strategy that corresponds to Case B, the maximum volume of natural gas that could be displaced would be $(345.6/577.0) \times 25$–26 million $Nm^3/day = 15.0$–15.6 million Nm^3/day. On the other hand, theoretically, a Case A strategy would allow 100 per cent natural gas displacement. It is clear from the numbers presented that cofiring biomass and natural gas could make the natural gas market more flexible, without drawbacks to electricity generation.

Table 9.6. Comparison of Case A, Case B and Case C

Parameter	NG-CC	Case A	Case B	Case C
NG demand [Nm^3/MWh]	222.4	–	78.4	170.5
NG displaced [1000 Nm^3/day/ 100 MW]	–	577.0	345.6	124.6
Biomass demand [t/MWh]	–	1.16	0.7	0.39
[t/day/100 MW]	–	2788.8	1682.4	926.6

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Sugarcane production in the State of São Paulo is estimated at 180 million tons per year. With this level of production, some 23.2 million tons of sugarcane trash could be recovered (50 per cent of the amount available, owing to topographic constraints; sugarcane trash availability is equivalent to approximately 25 per cent of sugarcane mass). The full availability of bagasse is estimated at 46.8 million tons/year (13 per cent fiber content and 50 per cent moisture), the ordinary surplus being about 10–15 per cent of the total availability. Achieving 6500 MW capacity, full implementation of the Case C strategy would demand 18.7 million tons of biomass per year, while the Case B strategy would require 33.9 million tons/year. Nowadays, trash is essentially burned at the field before sugarcane harvesting. For bagasse, there is not a market able to consume all the existing surplus. Hence, from the point of view of biomass availability, there is no particular constraint regarding the implementation of the cofiring alternatives analyzed here.

From the economic point of view, the preliminary results indicate that Case B can be considered as a reasonable alternative as the cost of electricity produced is kept at an acceptable level, and the investment IDR is not reduced to any large extent when biomass contribution is considered. If the biomass plant can be built mainly with equipment manufactured in Brazil (thus at lower capital cost), Case C is the best option, as it allows a reduction on the cost of electricity produced while enhancing the investment IDR. According to the results, to substitute biomass for natural gas in BIG-CC power plants (Case A) is not a good alternative as some amount of natural gas allows improvements in the system economics. Obviously, the opportunity to generate carbon credits from cofired plants would make a substantial difference on the economics of such alternatives.

The feasibility of Case B and Case C could be further improved with larger power units, taking advantage of economies of scale and, consequently, reducing the capital costs per unit energy generated. Strictly speaking, the location of the power plant would be a matter of concern regarding biomass transportation costs. The same is true regarding plant size – as the scale of the plant increases, costs related to logistics also increase.

9.6. FINAL REMARKS

Electricity production with the use of a renewable energy source on a sustainable basis is clearly the most important contribution of the cofiring alternatives discussed here. Additionally, natural gas could be used in a more rational manner, allowing gradual changes within the energy matrix and reduction of environmental impacts. In fact, a transition into biomass for power generation can be interesting for natural gas distribution companies. These companies could maximize their take-off

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in the beginning of the cash flow project and further extend their supply of natural gas at a very low cost (or even no cost) as the consumer market is further developed. This transition into biomass could also be considered for countries where the market of natural gas is already well developed. Another interesting point to be considered concerns the required investment to find new reserves at high marginal costs.

One of the main conclusions of a detailed study of the cofired option presented in Case B was that cofiring could be instrumental for the market development of the BIG-CC technology in its early stages. In fact, besides the possibility of overcoming technical constraints for the very first BIG-CC units, the enlargement of the fuel heating value due to the natural gas contribution boosts the plant efficiency and, consequently, contributes to the reduction of the cost of electricity generated from biomass. The cost reduction is, to a large extent, due to economies of scale. Small biomass-fueled gasification plants can benefit from the high efficiency and low capital costs of large combined cycles without scaling up the biomass parts. However, in the medium- to long-term, as the BIG-CC is further developed and gas turbines for biomass-derived gas are redesigned, co-fired combined cycles would probably be less justifiable (Souza, 2001). In the case of Brazil, successful experiences with cofiring natural gas and biomass could not only help foster BIG-CC market expansion, but also could allow a more efficient use of sugarcane residues for electricity generation.

Measures

$kPa = 10^3\ N/m^2$
LHV = Lower heating value
MMBTU = Million of British Thermal Units
Mol = Molecular weight
$MPa = 10^6\ N/m^2$

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