<u>Support Information:</u>
Technical, Economic and Greenhouse Gas Reduction Potential of Combined Ethanol Fermentation and Biofuel Gasification-Synthesis at Sulphite Pulping Mills

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****This support Information file formed part of the appendix for the PhD Thesis of the first author****

1 ECONOMIC INPUTS

In this section, the details and data on which the financial risk assessments are based are given. Firstly, the global parameters that describe the context in which the evaluations were completed are given. Thereafter, the procedure for calculating the total capital investment costs are given, which is based on values given in Table 1 for the ethanol production from SSL flow-sheets and Table 2 for synthetic fuel flow sheets. Thereafter, the procedures for simulating stochastic data using Monte Carlo methods is given, which is based on the data given in Table 3. Finally, the financial modelling relating to the income statement, cash flow statement and balance sheet, and the calculation of Key Economic Indicators is given as equation format. Non-stochastic parameters and costs of chemicals are given Table 4 and Table 5, respectively.

1.1 ECONOMIC ASSUMPTIONS

The parameters under which the economic evaluations of the scenarios were carried out are as follows:

- To simplify the economic analysis, an equity pool is assumed.
- The life of the plant is 25 years and the period of analysis is 20 years.
- The plant will have a salvage value of 20%, and the depreciation will be determined linearly from the initial value of the plant to the salvage value.
- Average operational time for 8000 hours.
- The South African Company Tax rate of 28% applies.
- The working capital is 5%

1.2 CAPITAL COST ESTIMATION

1. The capital cost of major equipment was estimated from literature using Equation 1. The values of the parameters in Equation 1 is in Table 1 for the ethanol production from SSL flow-sheets and Table 2 for synthetic fuel flow sheets

$$C_{ME} = RC*(SP_S/SP_R)^{SF}*IF*(CEPCI_{FY}/CEPCI_{RY})$$

Where C_{ME} – Capital Estimation of Major Equipment

RC – Reference quoted price

SP – Scaling Parameter, simulated (S) and reference value (R).

SF – Scaling Factor

IF- Installation Factor

CEPCI – Chemical Engineering Plant Cost Index, of the first year of analysis (FY), and reference year (RY).

2. Aspen Icarus[1] was used to estimate the costs of generic equipment (C_{GE}) such as pumps, turbines, compressors, flash tanks and process heaters and coolers.

3. The Total Equipment Costs (TEC)

   $TEC = \sum C_{ME} + \sum C_{GE}$

4. The Balance of Plant (BOP) [2], which estimates the costs of piping, instrumentation and wiring, is then calculated as:

   BOP (%) = 0.8867 / (Biomass Higher Heating Calorific Input (MW))$^{0.2096}$

5. The Total Installed Costs (TIC) are calculated as:

   TIC = TEC+BOP+SD+W

   Where: SD – Site Development, 13.5% of TEC [3]

   W – Warehouses, 1.5% of TEC [3]

6. Total Fixed Costs (TFC) is calculated as

   TFC = PC + FE +OC + C + O + TIC

   Where: PC – Prorateable Costs, 10% of TFC [3]

FE – Field Expenses, 10% of TFC [3]

OC – Office and Construction, 20% of TFC [3]

C – Contingency 10% of TFC [3]

O – Other Costs 10% of TFC [3]

7. Finally, the Total Investment Capital (TC) is calculated as

   $$TC = TFC + WC$$

   Where, WC – Working Capital, 5% of TFC. [3]

8. A location factor of 0.90 relative to a USA value of 1 is assumed on the Total Investment Capital [4].

Table 1: Parameters for Equipment Capital Estimate for Bioethanol Production

Unit	Scale Parameter	Base Value USD	Base Year	Base Price	Base CEPCI	Scale Factor	Installation
Detoxification Reactor[5]	kg/hr Hydrolysate	268762	2000	100144	392	0.71	1.40
Neutralisation Reactor[5]	kg/hr Hydrolysate	268762	2000	100144	392	0.71	1.40
Filter Press[5]	t/h solids	21	2000	1 285 736	392	0.60	2.40
Seed Fermenters' Coil[5]	Heat Duty	245	1997	4658	387	0.83	1.20
Seed Fermenters[6]	Volume m3	727	2000	149345	392	0.51	1.20
Seed Holding Tank[6]	Volume m3	872	2000	175626	392	0.51	1.20
Fermentation Cooler[5]	Heat Duty	2800	1997	3054	387	0.78	2.10
Fermentation Tank[6]	Volume m3	3596	2000	539848	392	0.51	1.20
Water scrubber[6]	kg/h total feed	25325	2000	127848	392	0.78	2.75
Distillation columns[3]	t/h ethanol	29	2010	3327914	560	0.60	2.40
Molecular sieve[3]	t/h ethanol	22	2010	2920000	560	0.60	1.80
Boiler	t/h steam	100	2010	31250000	560	0.73	1.00
Heat Exchangers[7]	Area m2	167	2010	44200	560	0.68	2.86
Digester[8]	m3	1	2010	714	560	0.91	1.00
Chiller[9]	Heat Duty kW	1	2002	299	396	0.80	1.00
Bag-house[5]	Kmol Flue gas	12935	2000	1784255	392	0.58	1.50
BIGCC Plant[10]	tons/day dry biomass	452	2007	39 458 000	525	0.6	1

Table 2: Parameters for Equipment Capital Estimate for Synthetic Fuel Production

Item	Parameter		Base Capacity	Cost (2012)	Factor	Installation
Biomass Dryer[11]	kg/hr Water Removed	kg/hr	1	334	1.00	1.00
Shredder[5]	ton/hr biomass	ton/hr	42	19 100 119	.70	1
Dual Fluidised Bed Gasification[12]	ton/hr biomass	ton/hr	42	19 100 119	0.70	1.00
Pressurised Gasification[12]	ton/hr biomass	ton/hr	42	17 835 175	0.70	1.00
Air Separation Unit[13]	O2 Flow kg/s	kg/s	64800	36 711 538	0.50	1.00
Rectisol Unit[2]	m3/h syngas	Nm3/hr	200000	31 392 767	0.63	1.32
Compressor[2]	KW	kW	70000	6 878 068	0.67	1.32
Heat Recovery Steam Generator[2]	Heat Load	MW	355	56 681 386	1.00	1.27
Distillation[15]	Methanol Product	ton/hr	87	18 684 256	0.67	1.00
Surface Condenser[16]	Heat Duty	MW	498	47 461 940	0.68	1.00
Vacuum Pump[17]	Flow	m3/s	13	283 954	0.79	2.80
Cooling Tower[5]	Heat Duty	kW	618903	2 439 305	0.78	1.20
Bag Filter[18]	Flow	m3/s	12	2 323 916	0.65	1.86
Gas Turbine[2]	Gross Generation	MW	150	66 166 311	0.75	1.27
Methanol Synthesis - Advanced[14]	Methanol Product	ton/hr	88	5 083 566	0.72	2.10
FT Reactor - Advanced[2]	FT Input Volume	MM SCF/hr	3	14 824 362	0.75	1.32

Table 3: Data for Stochastic Variables in Economic Models

	USA ethanol [19, 20]	Brazilian ethanol [21]	Electricity[22]	Methanol[23]	Crude oil [24]	PPI [25]	Interest Rates [26]
			kWhr	$ per litre	$ per litre		
2003	0.337	0.252	0.032	0.202	0.181	124.8	15.16
2004	0.422	0.254	0.039	0.208	0.240	127.7	11.31
2005	0.463	0.375	0.044	0.234	0.342	132.4	10.64
2006	0.674	0.508	0.048	0.296	0.410	142.6	11.14
2007	0.524	0.467	0.040	0.346	0.456	158.2	13.08
2008	0.587	0.520	0.040	0.435	0.610	180.8	15.12
2009	0.449	0.450	0.045	0.198	0.387	180.7	11.80
2010	0.483	0.612	0.054	0.274	0.500	191.6	9.91
2011	0.683	0.867	0.087	0.346	0.700	207.6	9.00
2012	0.611	0.666	0.106	0.351	0.702	220.5	8.78

1.3 PREPARATION OF STOCHASTIC SIMULATION

The method described here is a summary of the method found in Richardson et al[27], and Amigun et al[28].

1. The raw data for stochastic variables (i) in Table 3 is used to derived time dependant linear equations, or an average valued indices, where from future values can be projected from

$$TDTV_{i\ (t=2003\ldots2012))}=m_i\cdot t+c_i$$

or

$$EV_{i\ (t=2003,2012)}=Average_i\ (t=2003\text{-}2012)$$

Where: TDTV - time dependant trend value

m&c - trend line gradient and intercept.

EV - expected value

2. The residuals associated with each historical data point for each variable (Res_i) will be calculated as the difference between the measured variable and its associated trend/expected value

Thus: $Res_{i,\ (t=2003\ldots2012)}=MHV_{i(t)} - TDTV_{i(t)}$

OR

$Res_{i,\ (t=2003\ldots2012)}=MHV_{i(t)} - EV_{i(t)}$

Where: MHV - measured historic value

3. The relative variances (V) associated with each residual and the trended value will be calculated as:

$$V_{i\ (t=2003....2012)}=Res_{i(t)}/TDTV_{i(t)}$$

OR

$$V_{i\ (t=2003....2012)}=Res_{i(t)}/EV_{i(t)}$$

4. The multivariate empirical distribution (MVEMP) characterising the measured variances will be used to simulate a vector of simulated variances (SV).

Thus: $\{SV_i\}_{\ t=2012...2031}=MVEMP(V_{i,\ t=2003...2012})$

5. Future yearly values will be simulated either as future time dependant trend value (FTDTV) or future expected values (FEV) using the formulas determined for the trend lines in Step (1)

$$FTDTV_{i\ ,t=2012...2031}=TDTV_{,i\ ,t=2012...2031}$$

OR

$$FEV_{i,\ t=2012...2031}=EV_{i,\ t=2003...2012}$$

6. The simulated future variance will then be combined with the future yearly value to calculated the stochastic Forecasted Economic Input (SFI).

$$SFI_{i,\ ,t=2012...2031} = FTDTV_{i,\ t=2012...2031} + FTDTV_{i,\ t=2012...2031} * SV_{i,\ t=2012...2031}$$

OR

$$SFI_{i,\ ,t=2012...2031} = FEV_{i,\ t=2012...2031} + FEV_{i\ ,t=2012...2031} * SV_{i,\ t=2012...2031}$$

7. Simulation of the Operating time (T) would be accomplished with the GRKS distribution with a 10 day variation around the average operating time of 8000 hours.

Thus $T = GRKS(7760, 8000, 8240)$

1.4 Summary of Financial model for Calculating the Key Economic Variables

1. Simulating the Operating Expenses (OE) or Operating Incomes (OI)

   If stochastic (i): $OI_{i,\ t}$ or $OE_{i,\ t}$ = Flow $rate_i * T * SFI_{i,\ t}$

   If not stochastic (j) : $OE_{j,\ t}$ = Base $value_j * SFI_{PPI,\ t} / PPI_{t=2012}$

2. Interest Calculations

   Accrued $Interest_t$ = (Negative cash $balance)_{t-1} * SFI_{interest}$

   Interest $Earned_t$ = (Positive cash $balance)_{t-1}$ *Interest on Positive Bank Balance

3. Net Profit/loss$_t$ = $\sum OI_{i,t}$ + Interest Earned$_t$ - $\sum OE_{i,t}$ – Accrued Interest$_t$

4. Net Cash Income/Deficit = Net Profit/loss$_t$ – Depreciation$_t$.

5. Dividends$_t$ = Net Cash Income$_t$ * 25%

6. Tax$_t$=Net Income$_t$*28%

7. Cash Flow$_t$ = Net Cash Income$_t$ - Tax$_t$ - Dividends$_t$ OR = Net Cash Deficit

8. Cash Balance$_t$ = Cash Balance$_{t-1}$ + Cash Flow$_t$

9. Assets$_t$ = Plant Value$_{t-1}$-Depreciation$_t$+Land Value + Cash Balance$_t$ (IF >0)

10. Liabilities = IF Cash Balance$_t$ <0, Cash Balance$_t$, else = 0

11. Owners Equity$_t$ = Assets$_t$ – Liabilities$_t$

12. Delta Net Worth$_t$ = Owners Equity$_t$ - Owners Equity$_{t-1}$

13. Present Value$_t$ = (Delta Net Worth$_t$ + Dividends$_t$)/(1+Discount Rate$_{(=12.64\%)}$)^t

14. Net Present Value = -Total Capital Investment (TIC)+$\sum$Present Values

15. For IRR – Solve for the discount Rate to yield a zero Net Present Value

Table 4: Static Inputs for Economic Models

Sugarcane Trash[29]	US$/ton	20.44
Natural Gas[24]	US$/ton	893.00
O&M Costs: Ethanol Production	US$/litre	0.032
Added Maintenance Costs of Recovery Boiler[a]	US$/litre	0.003
CHPSC Operating Costs[10]	US$/kW	0.007
BIGCC Operating Costs[10]	US$/kW	0.013
O&M Costs: Methanol Synthesis[30]	US$/ton biomass	23.17
O&M Costs: FT Synthesis[31]	US$/ton biomass	25.63

*Estimated as the running costs of maintaining the bag-house filter that captures ash[3].

Table 5: Quotes for chemical costs used in bioethanol production

Chemical	Price	Unit	Year	Source	PPI	USD/kg	USD/kg
					reported year		2012
Sulphur	180	USD/m3	2006	1	142.6	0.087	0.134
Nitric Acid	215	USD/ton	2006	1	142.6	0.215	0.332
Ammonium Hydroxide	460	USD/ton	2007	1	154.85	0.460	0.655
Hydrochloric Acid	93.7	USD/ton	2010	1	191.6	0.094	0.145
Sulphuric Acid	200	USD/ton	2010	2	191.6	0.200	0.285
Molasses	184	USD/ton	2012	3	220.5	0.184	0.184
Sodium Hydroxide	850	USD/ton	2006	1	142.6	0.937	1.449
Corn Steep Liquor	177	USD/ton	2010	2	191.6	0.100	0.115
Ammonium Sulphate	335	USD/ton	2006	1	142.6	0.189	0.293
Di-ammonium Phosphate	230	USD/ton	2006	1	142.6	0.130	0.201
Ammonia	521	USD/ton	2006	1	142.6	0.295	0.455
Potassium Dihydro-Phosphate	41.25	USD/100lb	2006	1	142.6	0.909	1.406
Unrefined sugar	0.131	cent/pound	2010	3	191.6	0.289	0.332
Magnesium Sulphate	21	USD/lb	2006	1	142.6	0.463	0.716

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2 GREENHOUSE GAS INVENTORY

In this section, the data of the inventory for the Greenhouse Gas calculations. Tables 6 to 8 shows the data and the references or derivation of the numbers given are described in footnotes.

Table 6: Emissions per ton of Coal Used

Mining Emission			Reference/ Note
Methane Emissions per ton of Coal	0.77	m3/ton	(1)
Density of methane	0.68	kg/m3	Average density between 0 and 25°C
Thus	0.52	kg/ton	
CO2 Eq	13.27	kg/ton	a
Coal Transport			
GHG Transport of coal	0.20	kg/km	(2)
Distance	600.00	km	b
Tons per Trip	45.00	tons	b
Coal Combustion (per ton)	2.97	ton CO2 eqt	c

a. Calculated using the methane GWP equivalent of 25(3).
b. Information provided by Sappi Saiccor personnel.
c. Extracted from SimaPro(4) database, as generated by the CML2000 method.

Table 7: Greenhouse Gas associated with Chemicals

	kg CO2 eqt	Reference/ Note
Hydrochloric Acid	0.85	a, b
Sodium Hydroxide	1.41	a
Glucose	0.01	a
Corn Steep Liquor	1.90	c
Ammonia	2.40	A
Magnesium Sulphate	0.30	A
Di-ammonium Phosphate	2.81	A
Ammonium Sulphate	2.70	A

a. Extracted from SimaPro(4) database, as generated by the CML2000 method.
b. Hydrochloric acid or sulphuric acid used as possible acidifying agents.
c. Estimated from the energy balance of the Steeping Process(5), using the emissions for coal given in Table 6.

Table 8: Avoidance of fossil transport fuel GHG with Biofuels

Biofuel	kg CO2 eqt/l	Reference/ Note
Ethanol	1.57	a
Methanol	1.56	b
FT Syncrude	2.21	c

a. Based on the displacement of tail pipe greenhouse gas emission of fossil gasoline (based on the emission values extracted from the GREET 1.8 (2) model) by the use of bioethanol, on an thermal energy basis.
b. Based on the reduction of tail pipe greenhouse gas emission of Biodiesel 20 (based on the emission values extracted from the GREET 1.8 (2) model), if the fossil based methanol used in the biodiesel process is replaced by biomethanol. The contribution of methanol to the greenhouse gas emission of the production life-cycle of biodiesel was calculated at 9.6%, based on data given by Kumar et al(6) .
c. Based on the Based on the displacement of tail pipe greenhouse gas emission of fossil gasoline in a passenger car and diesel in a truck(based on the emission values extracted from the GREET 1.8 (2) model), assuming these fuels are alternatively originated from bio-syncrude.

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