TULLY SUGAR LTD

Cogeneration Project Investigation

July 2009

Background

Tully Sugar Limited (TSL) has previously investigated Cogeneration project opportunities, including a proposal in 2003 to purchase and install an existing 21MW condensing steam turbine generator (STG). Reports were prepared by Alstom ("Steam Turbine Technical Performance Study") and Sugar Research Institute ("Energy audit to achieve 45% process steam on cane") to assess the viability of operating the STG on higher pressure steam available from the 106t/h #3 ABB Boiler. The project did not proceed further, and the Renewable Energy Certificate (REC) market created by the 2%MRET nose-dived in 2005/6.

The announcement of the proposed 20%RET scheme by the new Labour Government in 2008 saw a revival of the REC market, and coupled with rising NEMMCO pool prices, offered promising returns for sugar mill Cogeneration projects. This has been tempered by the extraordinary increase in project construction costs over the past four years, requiring a detailed assessment of projects to minimize work scope without reducing project value.

Mackay Sugar Ltd (MSL) has been investigating a large cogeneration project at Racecourse Mill and has developed sugar factory heat balance and financial models incorporating Cogeneration plant, and has gained experience with plant design and specifications. MSL personnel have conducted this broad investigation for TSL, to assess a number of possible Cogeneration projects, identify the most promising, and indicate likely project returns.

A site visit to TSL in March 2009 was undertaken to update factory data and discuss staff preferences for the arrangement and operation of various Cogeneration options. The preference was to install a new HP boiler feeding steam to a new STG, however options to utilize the higher pressure capability of #3 Boiler would be investigated. Data from the earlier reports was reviewed and MSL heat balance models were modified to mimic the various project options within TSL's plant and operating constraints.

Scope of investigation and Methodology

This investigation is not a detailed feasibility study, but rather a study to determine the likely viability of installing a new HP boiler and STG, or alternatively to upgrade #3 Boiler and install a smaller STG dedicated to that boiler. The following options were modelled:

- **A.** Upgrade #3 Boiler to 45 barg; New 22MW condensing/extraction STG; 49.5% SOC
- **B.** Upgrade #3 Boiler to 45 barg; New 22MW condensing/extraction STG; 45% SOC
- **C.** New 140t/h 45 barg boiler; shut #1 Boiler; New 33MW condensing/extraction STG; 49.5% SOC

D. New 140t/h 45 barg boiler; shut #1 Boiler; New 33MW condensing/extraction STG; 45% SOC
E. New 140t/h 80 barg boiler; shut #1 Boiler; New 36MW condensing/extraction STG; 49.5% SOC
F. New 140t/h 80 barg boiler; shut #1 Boiler; New 36MW condensing/extraction STG; 45% SOC

The following procedure was used to determine the economic viability of each option:

- Modify the MSL heat balance models to TSL plant conditions for crushing and non-crushing operations;
- Using 2008 data, complete a matching run to test known operating outputs, specifically total generation, export, eligible generation (RECs), total surplus bagasse, LP venting, boiler loads, HP/LP steam balance, etc.;
- Include the new Cogen plant items, and adjust the existing powerhouse STG loads to maintain a steam balance (i.e no IP/LP make-up and no LP steam venting);
- For new boiler options, adjust the boiler steam flow so that all bagasse is consumed during the crushing season, allowing for start-up bagasse for the following season;
- For #3 Boiler upgrade options, adjust the boiler steam load to maintain the same bagasse consumption rate as the existing boiler at MCR;
- Adjust the pass-out flow from the new STG such that existing boiler loads are maintained at or near MCR;
- Adjust site electrical loads to reflect the impact of new Cogen plant and LP steam efficiency modifications;
- Determine the extra export, REC and Avoided TUoS revenue, above existing revenue;
- Estimate capital costs of new plant;
- Estimate increases in operating and maintenance costs of new plant;
- Predict forward black and REC pricing; and
- Prepare a simple discounted cash flow (DCF) analysis, assuming a 30 year project life.

The technical accuracy of the heat balance modeling should be reasonably good, however the capital estimates are only of first-order accuracy and are based on recent cost estimates prepared for the Racecourse project. Forward electricity and REC prices used in the modeling are based on recent indicative pricing received by MSL, but actual forward contract prices could vary significantly due to the current uncertainty of the 20%RET legislation and CPRS legislation.

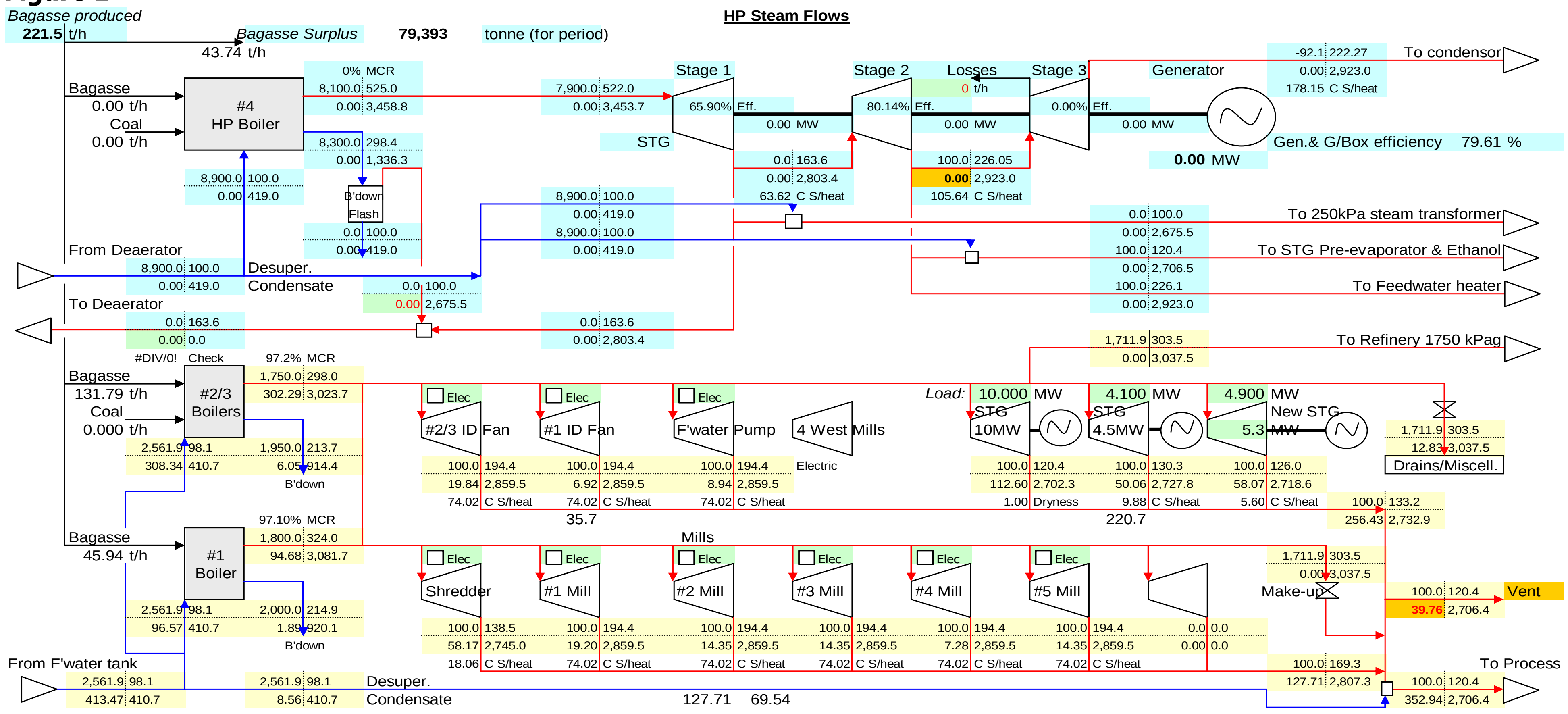
Until a detailed scope of work is established (with firm capital costs) and electricity and REC prices are set under a Power Purchase Agreement (PPA), the project returns should only be treated as indicative. However, the ranking of the options will be accurate enough for TSL to select the best option and take this forward to a detailed feasibility study, subject to the indicated project return meeting TSL's hurdle rate.

Matching Run

Figure 1 shows the HP steam model for current factory operations. Major inputs into the model include:

- Crush rate 713 TCH
- Crop 2.00mt

Figure 1



Boiler data:

	#4	#2/3	#1	
Pressure	8,100	1,750	1,800	kPag
Temperature	525	298	324	°C
MCR	150	311	97.5	t/h
Effic. -Bagasse	68.2%	67.0%	61.5%	(50% moist.)
-Coal	80%	70%		
Blowdown	1.0%	2.0%	2.0%	steam flow
Steam flow	0.0			t/h
#2 & #3 loads		76%	23.9%	% IP load
Fuel mix	100%	100%	100%	Bagasse (by energy)
FSL (ORER)		0.00%		(fossil fuel ratio)
Ash make	0.00	6.66	2.32	t/h (@60% m.)

Fuel data:

Crush rate		713	TCH
Crop		2,000.7	kt
Analysis period		19.220	weeks
Lost time		13.10%	available
Cane fibre		15.78%	(15,15.78,16.5)
Mud/Cane		6.05%	
Fibre/Mud		7.08%	
Bagasse:	Moist.	49.50%	wet basis
	Pol	1.83%	dry basis
	Ash	4.0%	dry basis
	Corr.factor	0.0%	extra consumption
Coal:	GCV	24,537	kJ/kg
	Ash	7.77%	as fired

STG data:

	Stage 1	Stage 2	Stage 3	
Design flow	150.0	150.0	76.0	t/h

Minimum Stage 3 flow	5%	design flow
Condensing pressure	9.17	kPaA
Generator capacity	36.0	MW
Gearbox efficiency	98.0%	

Legend:

Pressure (kPag)	*Temperature (C)*
Flow (t/h)	*Enthalpy (kJ/kg)*

○ ◉ 2

General data:

Miscell IP steam flow	1.8%	Cane
HP pipe pressure loss	200.0	kPag
IP pipe pressure loss	50.0	kPag
Deaerator pressure	0.0	kPag
Total generation	19.00	MW
Total site load	9.000	MW
Export	10.000	MW

Figure 2

Financial Summary (Crushing season)

Season length 19.22 weeks | 97.0% Plant availability | Ethanol Plant N (Y or N) | Fibre A (H,A or L) | Scheme M (M or Q)

Crop 2,000,654 tonne | *Description:* **713TCH (2008 current match)**

Parameter		Current Mode			Cogeneration Mode												
		1	2	Total	4		4		5		5		6		6		Total
Crushing rate	TCH				713		713		713		713		713		713		
LP steam/cane	%				49.5%		49.5%		49.5%		49.5%		49.5%		49.5%		
Period	wks				1.43		1.71		5.89		7.25		1.34		1.60		19.22
Lost time	%				13.1%		13.1%		13.1%		13.1%		13.1%		13.1%		
Crushing time	hrs				208.6		250.2		860.3		1,058.4		195.5		232.9		
Peak (P), Off-peak (O), Flat (F)					P		O		P		O		P		O		
Export price	$/MWh				63.03		33.54		63.92		31.19		95.69		31.19		
Boiler No.					#4	#2/#3	#4	#2/#3	#4	#2/#3	#4	#2/#3	#4	#2/#3	#4	#2/#3	
Boiler load	t/h				0.00	396.97	0.00	396.97	0.00	396.97	0.00	396.97	0.00	396.97	0.00	396.97	
STG condensor flow	t/h				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Site electrical loads:	kW																
Base Factory Load	kW					9,000.0		9,000.0		9,000.0		9,000.0		9,000.0		9,000.0	
Reduce LP SOC to 45%	kW					0.0		0.0		0.0		0.0		0.0		0.0	
Upgrade #3 boiler to 45bar	kW					0.0		0.0		0.0		0.0		0.0		0.0	
Shut #1 Boiler	kW					0.0		0.0		0.0		0.0		0.0		0.0	
New 150t/h Boiler	kW				0.0		0.0		0.0		0.0		0.0		0.0		
New STG	kW				0.0		0.0		0.0		0.0		0.0		0.0		
Demin Plant	kW				0.0		0.0		0.0		0.0		0.0		0.0		
Bagasse handling increase	kW				0.0		0.0		0.0		0.0		0.0		0.0		
Total	MW				0.000	9.000	0.000	9.000	0.000	9.000	0.000	9.000	0.000	9.000	0.000	9.000	
Total	MW					9.000		9.000		9.000		9.000		9.000		9.000	
Generation - while crushing	MW				0.000	19.000	0.000	19.000	0.000	19.000	0.000	19.000	0.000	19.000	0.000	19.000	
- while not crushing	MWh					416.4		476.0		1,716.8		2,122.0		363.0		464.9	
Export - while crushing	MW					10.000		10.000		10.000		10.000		10.000		10.000	
- while not crushing	MWh					235.3		274.3		949.4		1,176.9		205.3		266.6	
Bagasse - surplus while crushing	t/h					43.74		43.74		43.74		43.74		43.74		43.74	
- used while not crushing	tonne					3,234.4		3,695.6		13,378.7		16,523.9		2,837.7		3,606.5	
Coal	t/h				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Boiler make-up water	t/h				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Ash cartage	t/h				0.00	8.98	0.00	8.98	0.00	8.98	0.00	8.98	0.00	8.98	0.00	8.98	
ORER: - Fossil fuel ratio (FSL)	%					0.00%		0.00%		0.00%		0.00%		0.00%		0.00%	
- Non eligible aux (AUX)	MW				0.000	0.147	0.000	0.147	0.000	0.147	0.000	0.147	0.000	0.147	0.000	0.147	
Export - energy (adjusted)	MWh			0		2,252		2,693		9,266		11,408		2,095		2,517	**30,232**
- revenue	$			0		141,934		90,335		592,291		355,831		200,503		78,515	1,459,407
RECs - TLEG	MWh				339	4,030	388	4,831	1,399	16,621	1,729	20,450	296	3,772	379	4,499	
- AUX	MWh				0	31	0	37	0	127	0	156	0	29	0	34	
- FSL	MWh					0.0		0.0		0.0		0.0		0.0		0.0	
- Eligible generation				0		4,338		5,181		17,892		22,022		4,039		4,843	**58,315**
- revenue	$			0		216,900		259,050		894,600		1,101,100		201,950		242,150	2,915,750
Bagasse stockpiled	tonne			**0**		6,173		7,588		25,417		31,205		5,977		6,894	**83,255**
Coal consumed	tonne			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler treated make-up water	tonne			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ash cartage	tonne			0	0.0	1,872.5	0.0	2,246.0	0.0	7,721.9	0.0	9,500.1	0.0	1,754.6	0.0	2,090.0	25,185

- Start date 9 June
- Total lost time 13.1%
- Season length 19.2 weeks
- Cane fibre 15.78%
- Bagasse moisture 49.50%
- LP SOC 49.5% (353 t/h steam)
- Generation 19.0MW
- Site load 9.0MW

Boiler conditions were set as:

Parameter	#1 Boiler	#2 Boiler	#3 Boiler
MCR (t/h)	97.5	205	106
Steam flow (t/h)	94.7	199.3	103.3
Pressure (kPag)	1,800	1,780	1,750
Temperature (C)	324	302	295
Efficiency (%)	61.5	67.0	67.0
Blowdown (%)	2.0	2.0	2.0
Feedwater Temp (C)	98.1	98.1	98.1

Boilers #2 and #3 are shown combined in Figure 1. The model accounts for bagasse consumed during milling train stops, based on an assumed average duration of stops and a reducing LP steam consumption profile as stoppages progress. The model also assumes that powerhouse generation is controlled during stoppages to maintain a HP/LP steam balance.

Figure 2 shows a summary of the crushing season outputs for separate time periods. Cogeneration mode 4 covers Quarter2, mode 5 covers Q3, and mode 6 covers Q4. Outputs are then subdivided into electricity peak and off-peak time periods to calculate the revenue available under a likely quarterly/peak/offpeak PPA pricing structure. The far right column shows crushing season totals.

Predicted outputs from the model are compared with actual or observed outputs in the following table:

Parameter	Model prediction	Actual/observed (2008)
Total boiler load (t/h)	397	412
LP venting (t/h)	40	49
Make-up flow (t/h)	0	12
Total eligible generation (MWh)	58,300	58,800
Total export (MWh)	30,200	32,200
Total surplus bagasse (tonne)	83,000	~10,000

The eligible generation (for RECs) and export predictions are quite accurate, and the model emulates the ORER calculator by accounting for non-eligible auxiliary loads. The difference in the total boiler load, LP venting and make-up steam flows is due to the model solving for a boiler load that gives no make-up flow. However, TSL typically operates the boilers near MCR, producing a HP/LP make-up flow and heavier venting, as a means of controlling surplus bagasse. This would not occur under a Cogeneration project.

The parameter which produced a poor match was the amount of surplus bagasse predicted (83,000 tonne predicted, vs about 10,000 tonne actual). The model uses the common SRI formula for bagasse production and calorific value, with an option to use the equations published by Wright (ASSCT, 2003). The latter was used as it accounts for dirt in bagasse and results in a lower calculation of both bagasse produced and bagasse calorific value. Even so, the poor match requires further investigation, and could be attributed to:

- Higher dirt levels than used in the Wright model;
- Higher average bagasse moistures than the figure used (49.5%);
- Higher consumption during stoppages due to continued venting, rather than maintaining a HP/LP steam balance; or
- Lower boiler efficiencies than those supplied with the TSL data.

The model was not adjusted for subsequent Cogeneration modeling options with respect to bagasse availability, so the results may over-estimate the project outputs. It is recommended that a detailed feasibility study gives priority to determining the correct bagasse production and consumption figures, and should include an investigation by SRI into current boiler efficiencies.

New Boiler Arrangement (Options C, D, E and F)

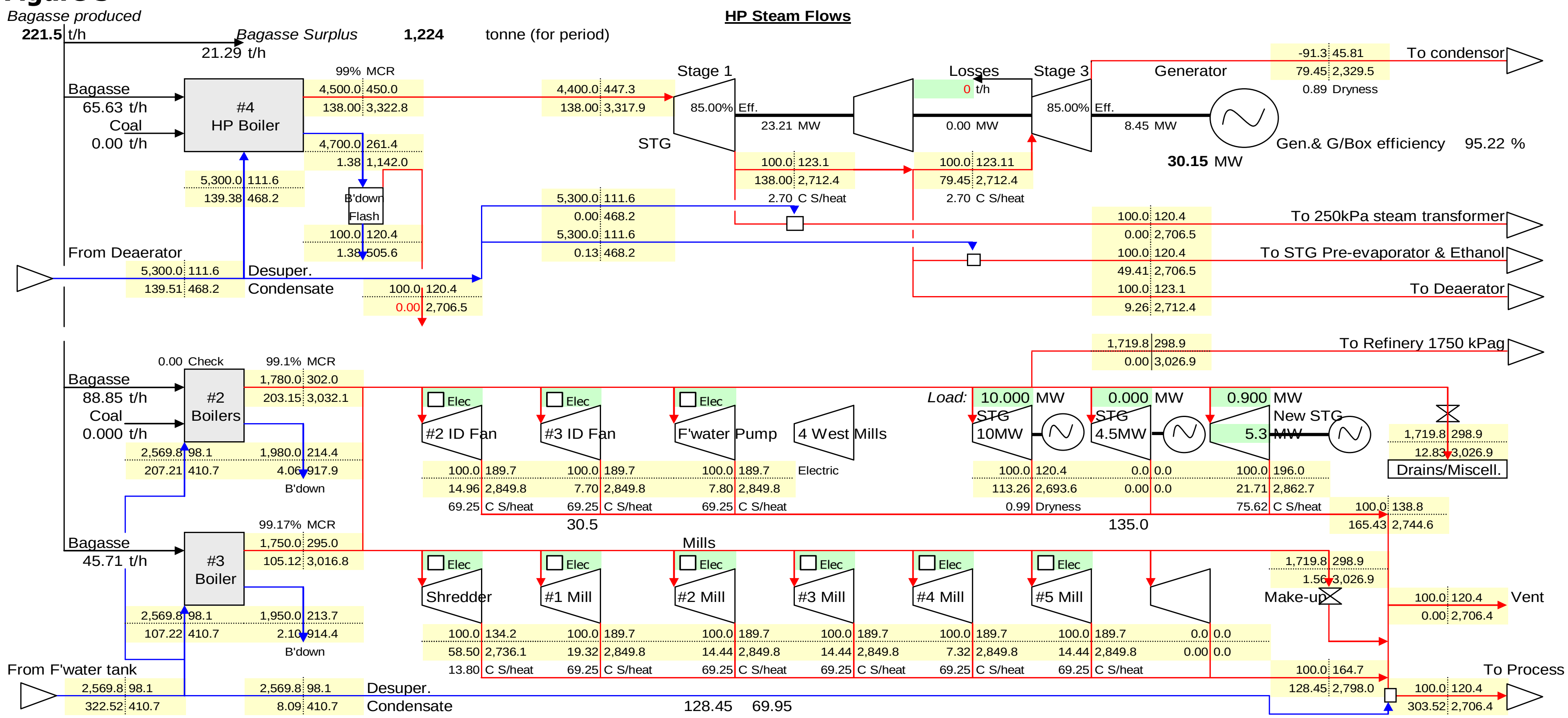
Figure 3 shows the general schematic of the HP steam circuit with a 140 t/h 45 barg boiler, 33MW condensing/extraction STG and cooling tower, and no change to the process plant (Option C). The boiler would be located beside #3 boiler, a new turbine hall located beside the existing powerhouse, and the cooling tower located to the immediate north of the turbine hall. Boiler #1 would be decommissioned and the bagasse feed conveyor would be extended. This would be the same arrangement for all the new boiler options.

Figure 4 shows the dedicated pre-evaporator (PE), the condensate return circuit from the PE and STG condenser to the deaerator, and the Demineralisation (demin) plant water circuit.

The following features have been modelled for operations with a new Cogen boiler:

- All auxiliary drives on the new boiler are electric (~1,700kW consumed);
- #2 and #3 boilers are operated at MCR and supply IP steam (17 barg) to all existing turbines;
- The reduced availability of IP steam results in the 2 x 2.2MW TA's being decommissioned, and the 5.5MW TA load reduced to about 1 MW (an electric drive would need to installed on the shredder to reclaim the lost powerhouse load, and this would create extra RECs but little extra export);
- The IP powerhouse TA loads control the LP steam pressure, so there is no IP/LP make-up steam flow or LP steam venting (i.e. steam balance is maintained);
- HP steam from the new boiler only supplies the new STG;

Figure 3



Boiler data:

	#4	#2	#3	
Pressure	4,500	1,780	1,750	kPag
Temperature	450	302	295	°C
MCR	140	205	106	t/h
Effic. -Bagasse	67.0%	67.0%	67.0%	(50% moist.)
-Coal	80%	70%		
Blowdown	1.0%	2.0%	2.0%	steam flow
Steam flow	138.0			t/h
#2 & #3 loads		66%	34.1%	% IP load
Fuel mix	100%	100%	100%	Bagasse (by energy)
FSL (ORER)		0.00%		(fossil fuel ratio)
Ash make	3.31	4.49	2.31	t/h (@60% m.)

Fuel data:

Crush rate		713	TCH
Crop		2,000.7	kt
Analysis period		19.220	weeks
Lost time		13.10%	available
Cane fibre		15.78%	(15,15.78,16.5)
Mud/Cane		6.05%	
Fibre/Mud		7.08%	
Bagasse:	Moist.	49.50%	wet basis
	Pol	1.83%	dry basis
	Ash	4.0%	dry basis
	Corr.factor	0.0%	extra consumption
Coal:	GCV	24,537	kJ/kg
	Ash	7.77%	as fired

STG data:

	Stage 1	Stage 2	Stage 3	
Design flow	140.0	140.0	80.0	t/h

Minimum Stage 3 flow	5%	design flow
Condensing pressure	10.00	kPaA
Generator capacity	35.0	MW
Gearbox efficiency	98.0%	

General data:

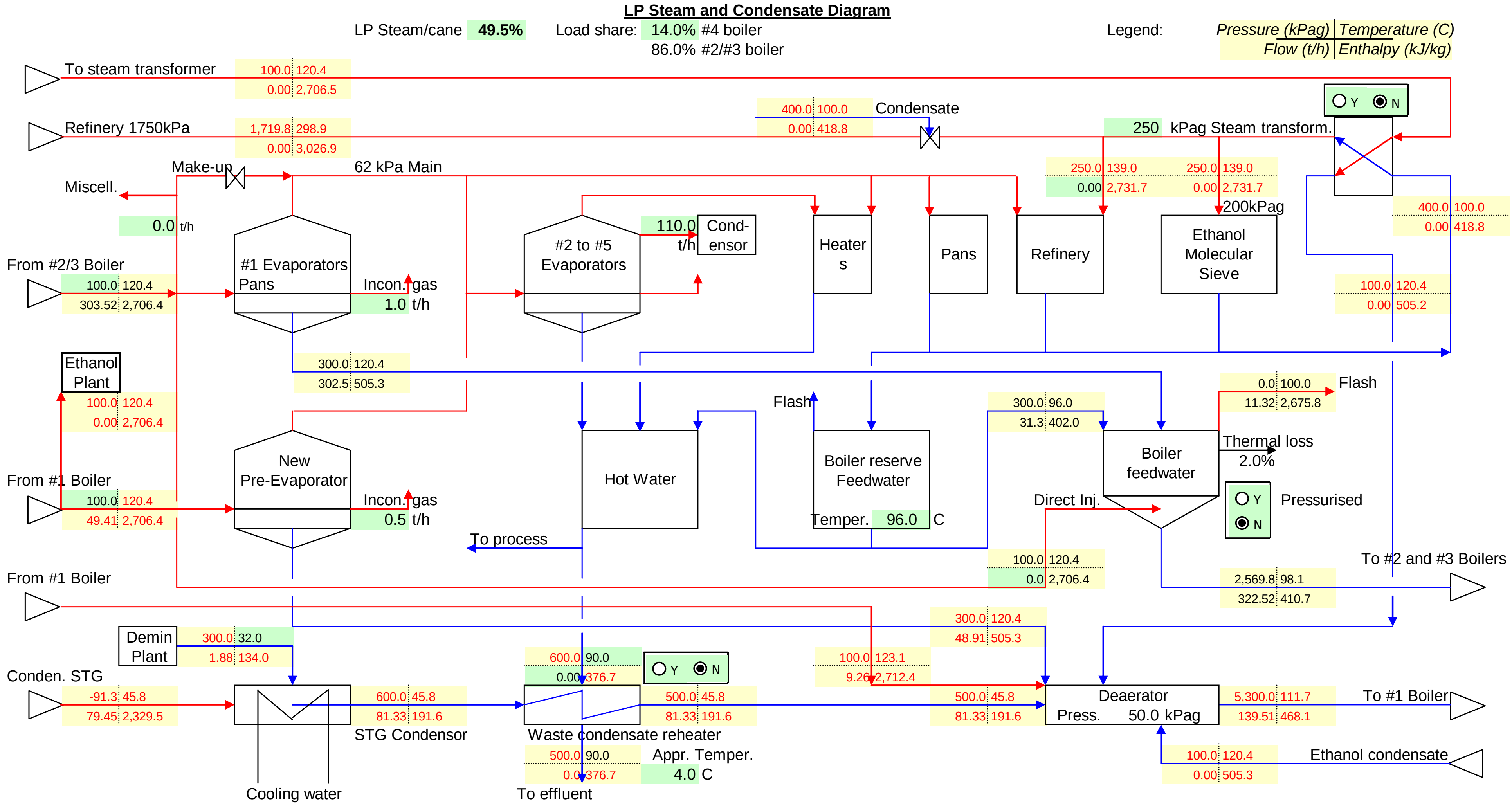
Miscell IP steam flow	1.8%	Cane
HP pipe pressure loss	100.0	kPag
IP pipe pressure loss	50.0	kPag
Deaerator pressure	50.0	kPag
Total generation	41.05	MW
Total site load	11.297	MW
Export	29.751	MW

Legend:

Pressure (kPag)	*Temperature (C)*
Flow (t/h)	*Enthalpy (kJ/kg)*

2

Figure 4



LP Steam and Condensate Diagram
LP Steam/cane 49.5%
Load share: 14.0% #4 boiler
86.0% #2/#3 boiler
Legend:
Pressure (kPag) | Temperature (C)
Flow (t/h) | Enthalpy (kJ/kg)
To steam transformer
100.0 120.4
0.00 2,706.5
Refinery 1750kPa
1,719.8 298.9
0.00 3,026.9
400.0 100.0
0.00 418.8
Condensate
Y N
250 kPag Steam transform.
Make-up
62 kPa Main
Miscell.
0.0 t/h
250.0 139.0
0.00 2,731.7
250.0 139.0
0.00 2,731.7
200kPag
400.0 100.0
0.00 418.8
From #2/3 Boiler
100.0 120.4
303.52 2,706.4
#1 Evaporators
Pans
Incon. gas
1.0 t/h
#2 to #5
Evaporators
110.0
t/h
Cond-
ensor
Heater
s
Pans
Refinery
Ethanol
Molecular
Sieve
100.0 120.4
0.00 505.2
Ethanol
Plant
300.0 120.4
302.5 505.3
100.0 120.4
0.00 2,706.4
0.0 100.0
11.32 2,675.8
Flash
300.0 96.0
31.3 402.0
Flash
Hot Water
Boiler reserve
Feedwater
Temper. 96.0 C
Boiler
feedwater
Thermal loss
2.0%
From #1 Boiler
New
Pre-Evaporator
100.0 120.4
49.41 2,706.4
Incon. gas
0.5 t/h
Direct Inj.
Y
N
Pressurised
To process
100.0 120.4
0.0 2,706.4
To #2 and #3 Boilers
From #1 Boiler
2,569.8 98.1
322.52 410.7
300.0 120.4
48.91 505.3
Demin
Plant
300.0 32.0
1.88 134.0
600.0 90.0
0.00 376.7
Y N
100.0 123.1
9.26 2,712.4
Conden. STG
-91.3 45.8
79.45 2,329.5
600.0 45.8
81.33 191.6
STG Condensor
500.0 45.8
81.33 191.6
500.0 45.8
81.33 191.6
Deaerator
Press. 50.0 kPag
5,300.0 111.7
139.51 468.1
To #1 Boiler
Waste condensate reheater
500.0 90.0
0.0 376.7
Appr. Temper.
4.0 C
100.0 120.4
0.00 505.3
Ethanol condensate
Cooling water
To effluent

- A controlled steam pass-out from the STG provides 100kPag steam to a dedicated pre-evaporator, as there is insufficient exhaust steam from the IP turbines to meet all factory LP steam requirements. The amount of pass-out steam reduces significantly if LP steam-on-cane (SOC) efficiency measures are implemented, releasing more steam for the condensing stage of the STG and increasing generation;
- Pass-out steam is also used as the heating source for the HP boiler deaerator which has been modelled at 50kPag to ensure oxygen removal from returning condensate;
- The balance of the steam that is not passed out expands through to the condenser from which condensate is pumped back to the deaerator;
- Condensate from the dedicated pre-evaporator or heater is also returned to the deaerator for re-heating;
- A demin plant is included to supply quality make-up feedwater to the new boiler, mainly to replace blow-down steam from the new boiler;
- The cooling tower water pumps and fan will increase the site electrical demand by about 850kW, depending on the condenser steam flow; and
- Any variations in LP factory steam demand (due to cyclic pan loads) should be accommodated by varying the pass-out steam from the new STG to the PE. The condensing stage of the STG therefore takes up the balance of this variation resulting in stable boiler loads.

Two boiler pressures have been modelled:

- Options C and D: 45barg and 450C steam
- Options E and F: 80 barg and 525C steam (same as MSL Cogen boiler)

The HP boiler load has been determined so that all bagasse is consumed during the crush, and no operations occur during the non-crush. Assuming a boiler HHV efficiency of 67.0%, approximately 65 t/h of bagasse is consumed by this boiler. The resulting boiler loads are:

- 45barg: 138 t/h
- 80barg: 132 t/h

For all options considered, boiler pressures are 45barg or 80barg, and it is recommended that the following features be implemented to control boiler feedwater quality to the HP boiler and minimize blow-down rates:

- Segregate the STG pass-out steam from the IP boiler turbine exhaust steam by installing a dedicated PE or heater, which returns condensate only to the HP boiler deaerator, and
- Install a demineralization plant

These features have been included in the capital estimates for all options. The quality of water make-up water to the STG cooling tower also needs to be suitable to maximize concentration cycles (i.e. minimise make-up) and it is recommended that a factory condensate stream be considered to supplement raw water for this purpose.

Another option that has not been modelled, but will increase the generation output, is to install a STG condensate reheater using either #2 effet vapour, or a factory waste hot water stream. The condensate returning from the STG will be around 45C and this needs to be heated by pass-out steam in the dearator, so any heating by a factory stream will reduce the pass-out needed. SRI report number 3215 for TSL recommends #2 vapour as this is also consistent with reducing the LP SOC.

For all options, the bagasse firing rate is very similar to current operations, so the capacity of bagasse conveyors and the ash plant is of no concern.

Upgrade #3 Boiler (Options A and B)

Instead of installing a new boiler, TSL has the opportunity to increase the pressure and temperature of the existing #3 ABB Boiler to 45 barg and 450C respectively, and install a matching STG. This has some obvious logistical advantages over installing a new HP boiler, including:

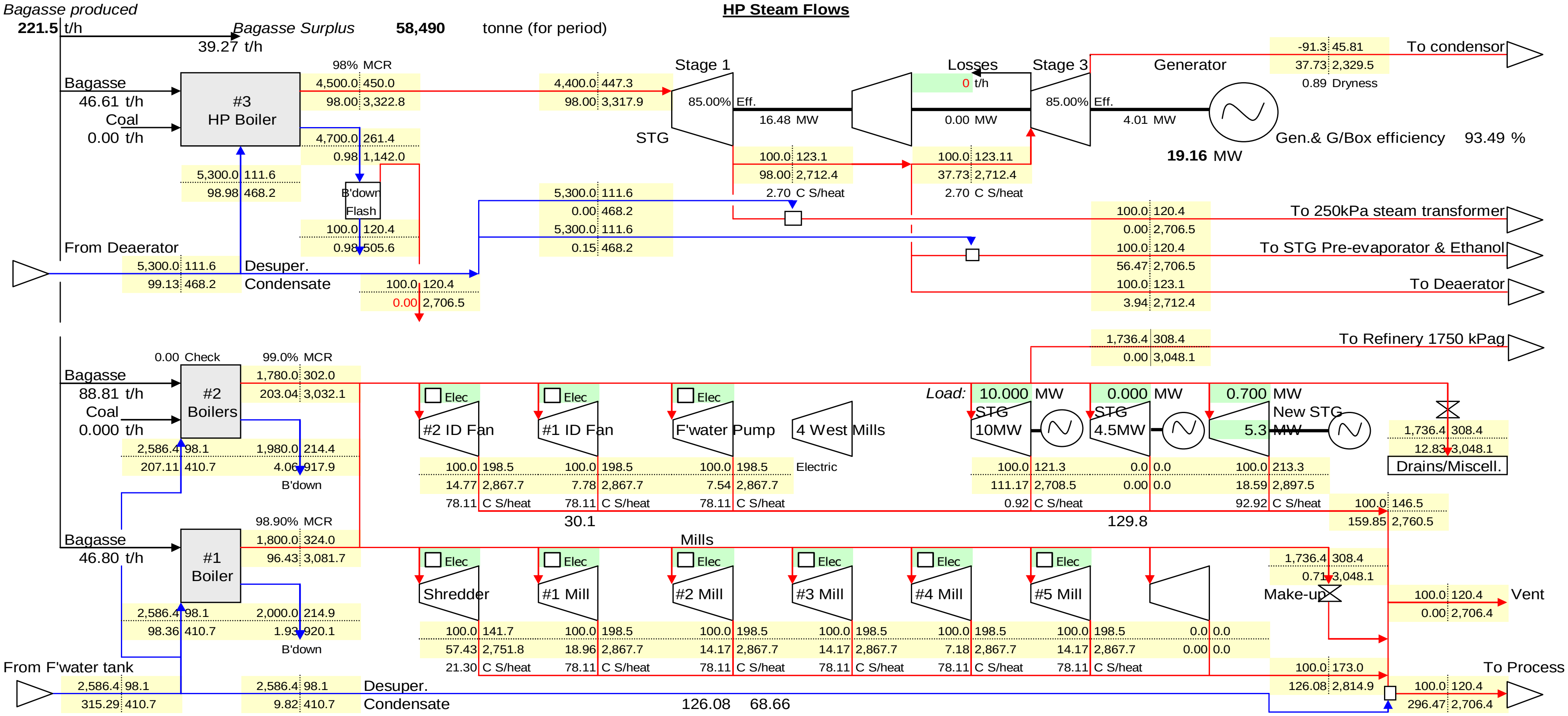
- No site preparation or space restrictions;
- No extension required for the bagasse feed conveyor;
- No change to the bagasse feed distribution to all boilers;
- No requirement to partition #3 chimney for dual boiler operation; and
- Much lower cost and commissioning risk.

The statements made in the 2003 Alstom report regarding the boiler capacity have been assumed correct and have been incorporated in the design modelling for an upgraded #3 boiler. These include:

- Steam conditions of 45 barg and 450C;
- Minimal work required to maintain the boiler at it's current nominated efficiency of 67%;
- Assumption that the heat-to-steam rate remains constant (i.e. steam output will fall marginally at the higher steam conditions to maintain a constant bagasse firing rate);
- A new, larger superheater needs to be installed;
- Steam outlet pipework, and isolation and relief valves need replacing;
- A new dedicated feedwater pump is required to supply water at the higher pressure;
- All other boiler components remain unchanged.

Figure 5 shows the HP and IP steam circuits for Option A, while Figure 6 shows the LP pass-out steam flows and condensate return to the deaerator. The IP steam circuit for #1 and #2 boiler under this arrangement is very similar to the operation of #2 and #3 under the new boiler options, although the lower capacity of #1 boiler means that the IP powerhouse load needs to reduce further. The pass-out from the STG also needs to increase by about 8 t/h to compensate for the lower exhaust steam from the IP turbines.

Figure 5



Boiler data:

	#3	#2	#1	
Pressure	4,500	1,780	1,800	kPag
Temperature	450	302	324	°C
MCR	100	205	97.5	t/h
Effic. -Bagasse	67.0%	67.0%	61.5%	(50% moist.)
-Coal	80%	70%		
Blowdown	1.0%	2.0%	2.0%	steam flow
Steam flow	98.0			t/h
#2 & #3 loads		68%	32.2%	% IP load
Fuel mix	100%	100%	100%	Bagasse (by energy)
FSL (ORER)		0.00%		(fossil fuel ratio)
Ash make	2.35	4.48	2.36	t/h (@60% m.)

Fuel data:

Crush rate		713	TCH
Crop		2,000.7	kt
Analysis period		19.220	weeks
Lost time		13.10%	available
Cane fibre		15.78%	(15,15.78,16.5)
Mud/Cane		6.05%	
Fibre/Mud		7.08%	
Bagasse:	Moist.	49.50%	wet basis
	Pol	1.83%	dry basis
	Ash	4.0%	dry basis
	Corr.factor	0.0%	extra consumption
Coal:	GCV	24,537	kJ/kg
	Ash	7.77%	as fired

STG data:

	Stage 1	Stage 2	Stage 3	
Design flow	98.0	98.0	50.0	t/h
Minimum Stage 3 flow	5%	design flow		
Condensing pressure	10.00	kPaA		
Generator capacity	22.0	MW		
Gearbox efficiency	98.0%			

General data:

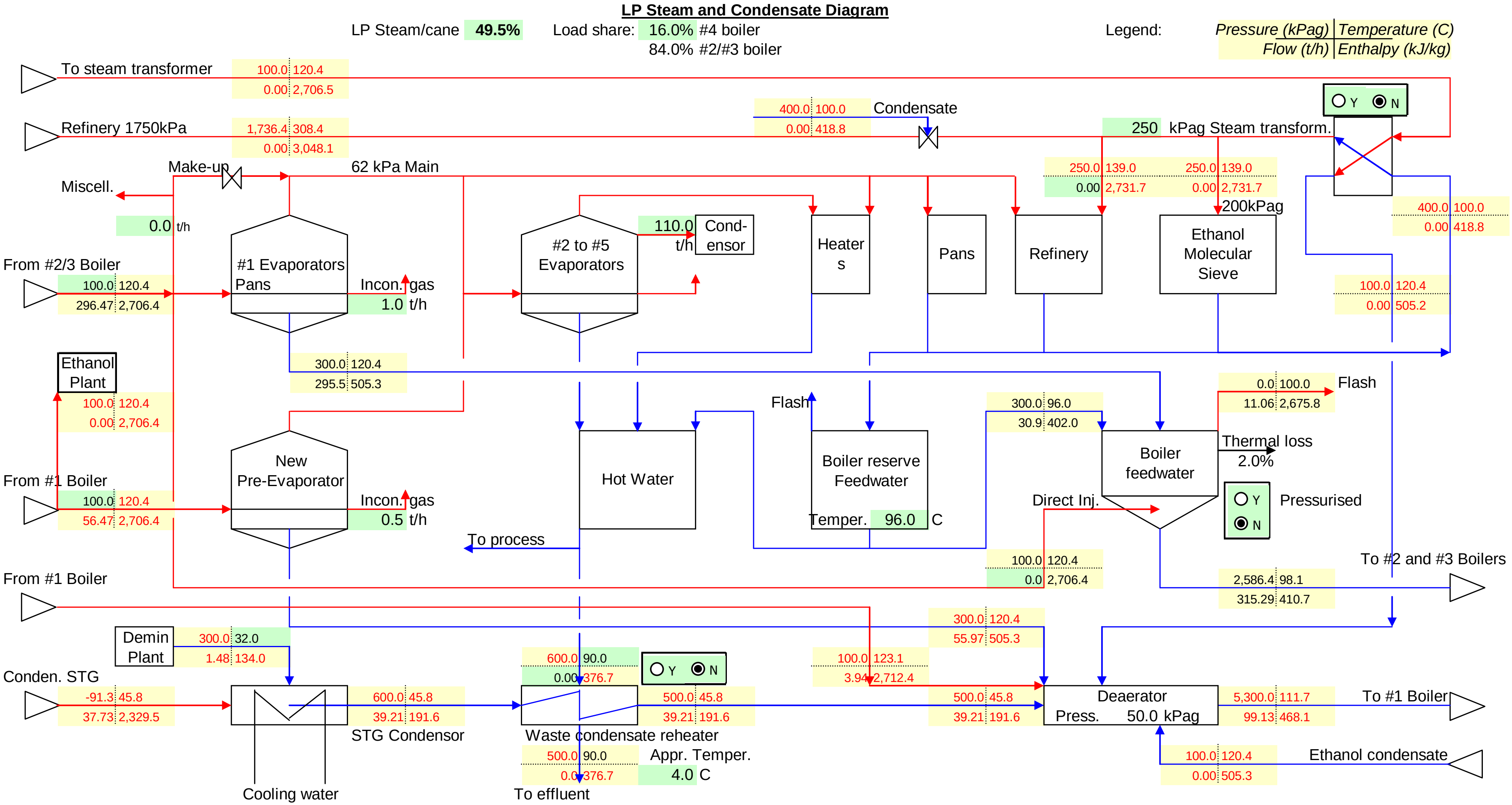
Miscell IP steam flow	1.8%	Cane
HP pipe pressure loss	100.0	kPag
IP pipe pressure loss	50.0	kPag
Deaerator pressure	50.0	kPag
Total generation	29.86	MW
Total site load	10.607	MW
Export	19.255	MW

Legend:

Pressure (kPag) | *Temperature (C)*
Flow (t/h) | *Enthalpy (kJ/kg)*

2

Figure 6


LP Steam and Condensate Diagram
LP Steam/cane 49.5%
Load share: 16.0% #4 boiler
84.0% #2/#3 boiler
Legend:
Pressure (kPag) | Temperature (C)
Flow (t/h) | Enthalpy (kJ/kg)
To steam transformer
100.0 120.4
0.00 2,706.5
Refinery 1750kPa
1,736.4 308.4
0.00 3,048.1
400.0 100.0
0.00 418.8
Condensate
250 kPag Steam transform.
Y N
Make-up
62 kPa Main
Miscell.
0.0 t/h
250.0 139.0
0.00 2,731.7
250.0 139.0
0.00 2,731.7
200kPag
400.0 100.0
0.00 418.8
#1 Evaporators
Pans
#2 to #5
Evaporators
110.0 t/h
Cond-
ensor
Heater
s
Pans
Refinery
Ethanol
Molecular
Sieve
From #2/3 Boiler
100.0 120.4
296.47 2,706.4
Incon. gas
1.0 t/h
100.0 120.4
0.00 505.2
Ethanol
Plant
300.0 120.4
295.5 505.3
100.0 120.4
0.00 2,706.4
0.0 100.0
11.06 2,675.8
Flash
Flash
300.0 96.0
30.9 402.0
New
Pre-Evaporator
Hot Water
Boiler reserve
Feedwater
Boiler
feedwater
Thermal loss
2.0%
From #1 Boiler
100.0 120.4
56.47 2,706.4
Incon. gas
0.5 t/h
To process
Temper. 96.0 C
Direct Inj.
Y
N
Pressurised
100.0 120.4
0.0 2,706.4
To #2 and #3 Boilers
From #1 Boiler
2,586.4 98.1
315.29 410.7
300.0 120.4
55.97 505.3
Demin
Plant
300.0 32.0
1.48 134.0
600.0 90.0
0.00 376.7
Y N
100.0 123.1
3.94 2,712.4
Conden. STG
-91.3 45.8
37.73 2,329.5
600.0 45.8
39.21 191.6
500.0 45.8
39.21 191.6
500.0 45.8
39.21 191.6
Deaerator
Press. 50.0 kPag
5,300.0 111.7
99.13 468.1
To #1 Boiler
STG Condensor
Waste condensate reheater
500.0 90.0
0.0 376.7
Appr. Temper.
4.0 C
100.0 120.4
0.00 505.3
Ethanol condensate
Cooling water
To effluent

The HP steam circuit from the upgraded #3 boiler is identical to the new boiler options, with HP steam feeding a 22MW STG, pass-out steam feeding a dedicated PE and a new deaerator, a condenser with condensate return pumps, and a cooling tower. The condenser and cooling tower are only about half the capacity of the new boiler options, because the HP steam flow from #3 boiler is 98 t/h compared to 132 / 138 t/h from the new boiler.

A further requirement is the electrification of #3 boiler ID fan and the new #3 feedwater pump. This is needed for the IP steam balance so that the IP powerhouse loads can be maintained, and RECs are effectively created.

The model predicts that this mode of operation (i.e. both upgraded #3 Boiler options) will result in about 60,000 tonne of surplus bagasse by the end of the season. This is subject to the earlier comments regarding bagasse quantities predicted by the matching run. Compared to the new boiler options which result in no surplus bagasse, this option offers the opportunity to operate into the non-crush and obtain a better capacity factor for the new installed plant. It also gives access to higher pool prices in Quarter 4, compared to Quarters 2 and 3. The issue for TSL is managing the wet weather risk of storing and reclaiming bagasse during November and December.

Non-Crush Cogen Operations (Options A and B only)

Figure 7 shows how the upgraded #3 boiler and 22MW STG would operate during the non-crush in fully condensing mode. The only STG pass-out steam at 100 kPa would be to supply 9 t/h steam to the deaerator for condensate reheating. The boiler load of 78 t/h has been chosen so that the steam flow to the condenser is similar to that in the crushing season. This provides maximum capacity utilization of the condenser. There is obviously an option to install a larger condenser and increase the boiler load to MCR (98 t/h) and effectively reduce the non-crush operations by about 20%.

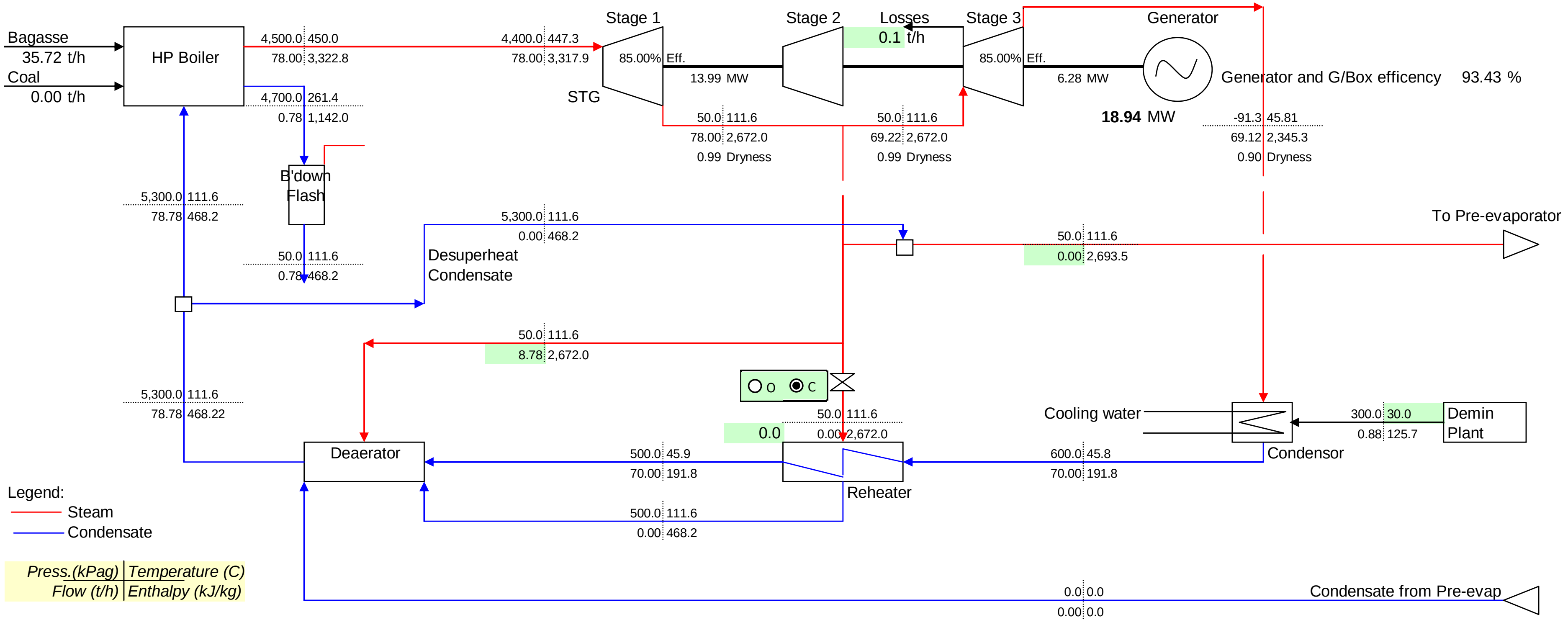
Figure 8 summarises the operation and outputs during this period. 60,000 tonne of bagasse would be consumed within 10 weeks, or 8 weeks with a full capacity condenser and cooling tower. Assuming an early June start to crush and a 19-20 week season, this operation would be completed by Christmas. Understandably, this would create some challenges with bagasse reclamation during Tully’s wet weather periods, but the rewards are significant.

The model predicts a generation load of 18.9 MW, a site load of 2.4 MW (allowing 0.5 MW for general mill maintenance that doesn’t need to be imported) and export of 16.5 MW. An extra 27,800 RECs would be produced in this period, allowing for the much higher proportion of non-eligible auxiliary load during this period.

Since the #3 boiler HP steam and condensate system is effectively segregated from the #1 and #2 boiler steam circuit, the transition to non-crush generation would be continuous and seamless, and maintenance could be undertaken safely on all milling and process plant. There may be a need for one block-and-bleed isolation valve on the pass-out pipe to the dedicated PE.

Figure 7

HP Steam Diagram (Period 1)



Boiler data:

Pressure	4,500	kPag
Temperature	450.0	°C
Steam flow	78.0	t/h
MCR	100.0	t/h
Effic. -Bagasse	67.0%	(50% moist.)
-Coal	70.0%	
Blowdown	1.0%	steam flow
FSL (ORER)	0%	(fossil fuel ratio)
Ash make	1.79	t/h (@60% m.)

Fuel data:

Fuel mix	100%	Bagasse (by energy)
Bagasse:		
Moisture	50.0%	
Pol	1.83%	dry basis
Ash	4.0%	dry basis
Correct.factor	0.0%	extra consumption
Coal:		
GCV	24,537	kJ/kg
Ash	7.77%	as fired

STG data:

	Stage 1	Stage 2	Stage 3	
Design flow	98.0	98.0	70.0	t/h

Minimum Stage 3 flow	5%	design flow
Condensing pressure	10.00	kPaA
Generator capacity	22.0	MW
Gearbox efficiency	98.0%	

General data:

HP pipe pressure loss	100.0	kPag
Deaerator pressure	50.0	kPag

Figure 8

Performance Summary (Non-crush)

Stored bagasse 61,000 tonne 97.0% Plant availability 19.22 wk crush *Period*

Transport & storage costs $ - /tonne *Description:* **All options with upraded #3 Boiler; 61,000 t bagasse.**

Parameter		Current Mode			Operating Mode												
		1	2	Total	1	1	1	1	2	3	2	3					Total
Operating Price period (**1, 2 or 3**)		Refinery non-crush			1	1		0		0		0		0		0	
Portion of operating period	%	10%	90%		100.00%												
From price period					End Crush	End Crush											
To price period					End Q4	End Q4											
Boiler No.		2	2		1	1											
Peak (P), Off-peak (O), Flat (F)		F	F		P	O											
Total operating period	hr	5,531.0	5,531.0		765.0	926.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Actual operating hours	hr	553.1	4,977.9	5,531.0	765.0	926.0											
Export price	$/MWh	28.00	28.00		42.00	19.08											
Boiler load	t/h	67.78	67.62		78.00	78.00											
STG condensor flow	t/h	0.00	0.00		69.12	69.12											
Generation	MW	3.239	3.177		18.944	18.944											
Site electrical loads: - Boiler	kW	241.3	252.2		511.7	511.7											
- STG	kW	80.3	80.3		847.0	847.0											
- Feedwater	kW	43.8	43.8		202.4	202.4											
- Demin plant	kW	17.6	17.6		50.0	50.0											
- Bagasse handling	kW	86.9	0.0		200.0	200.0											
- Coal handling	kW	0.0	15.1		0.0	0.0											
- Cooling Tower	kW	0.0	0.0		0.0	0.0											
- Ash handling	kW	97.6	97.6		150.0	150.0											
- Shared plant/Misc.	kW	89.1	89.1		0.0	0.0											
- Refinery process	kW	1,703.3	1,703.3		0.0	0.0											
- Ethanol Plant	kW				0.0	0.0											
- Mill maintenance	kW	863.1	863.1		500.0	500.0											
#REF!	MW	3.240	3.177		2.461	2.461											
Bagasse	t/h	29.68	0.00		35.72	35.72											
Coal	t/h	0.00	9.49		0.00	0.00											
Boiler treated make-up water	t/h	15.29	15.29		0.88	0.88											
Ash cartage	t/h	1.85	1.78		1.79	1.79											
ORER: - Fossil fuel ratio (FSL)	%	0.0%	100.0%		0.0%	0.0%											
- Non eligible aux (AUX)	MW	0.123	0.118		1.961	1.961											
Export - power	MW	-0.001	0.000		16.483	16.483											
- energy (adjusted)	MWh	-0.4	-1.3	-1.7	12,231.2	14,806.0											**27,037.3**
- revenue	$	0	0	0	513,712	282,499											796,212
RECs - TLEG	MWh	1,791.5	15,814.9		14,057.5	17,016.8											
- AUX	MWh	67.9	585.6		1,455.3	1,761.6											
- FSL	MWh	0.0	15,814.9		0.0	0.0											
- RECs created		1,723	0	1,723	12,602	15,255											**27,857.0**
- revenue	$	86,150	0	86,150	630,100	762,750											1,392,850
Bagasse consumed	tonne	16,415.4	0.0	16,415	26,505.8	32,085.5											58,591.3
Bagasse remaining	tonne	0.0	0.0			2,408.7		2,408.7		2,408.7		2,408.7		2,408.7		2,408.7	
Coal consumed	tonne	0.0	47,226.8	47,227	0.0	0.0											**0.0**
Boiler treated make-up water	tonne	8,459.1	76,116.6	84,576	653.0	790.5											1,443.5
Ash cartage	tonne	1,026.0	8,855.0	9,881	1,325.3	1,604.3											2,929.6
Revenue - Export	$			0											796,212		796,212
- RECs	$			86,150			Export		Eligible	Bagasse	Coal				1,306,700		1,392,850
Costs - Bagasse	$			0		P	OP	Total	Generation						0		0
- Coal	$			0	Q4	12,231.2	14,806.0	27,037.3	27,857.0	58,591.3	0.0			*Change:*	0		0
- Boiler water	$			29,602	Q1	0.0	0.0	0.0	0.0	0.0	0.0				-29,096		505
- Ash cartage	$			0	Q2	0.0	0.0	0.0	0.0	0.0	0.0				0		0
Net Revenue	$			56,548				**27,037.3**	**27,857.0**	58,591.3	0.0				2,132,008		2,188,556

LP SOC Efficiency Options

SRI Report 3215 (Hodgson, Lavarack and Broadfoot) was completed in 2003 and identifies a number of process plant modifications that would reduce TSL's LP steam consumption from 49.5% to 45% cane. Plant modifications recommended include:

- Substituting ESJ for flocculant dilution water
- Substituting ESJ for A molasses dilution water
- New 514m^2 pre-primary heater using #4 effet vapour
- Changing primary heaters from #1 effet vapour to #2 vapour
- Changing the A continuous pan from LP steam to #1 effet vapour
- Upgrade the ESJ heater with a new plate heater
- Use the displaced ESJ heater as an STG condensate reheater, using #2 effet vapour
- Pressurize the condensate system for the IP boilers

The last item doesn't reduce LP steam usage, but does conserve bagasse and water, and adds value to the cogeneration project (it is being incorporated in the Racecourse Cogeneration project).

This report has not been revisited, but it has been assumed that these modifications would be included in the three options where 45% LP SOC has been modeled. However, the original capital estimates have been significantly upgraded to reflect recent pricing increases obtained for the Racecourse project.

The revenue benefit of reducing LP SOC to 45% can be seen in the following sections, but in summary, it adds about 3 MW of output to each option. This would equate to approximately $1.0m extra revenue per annum for a capital outlay of around $2.5m.

Project Outputs

Project outputs for all options are given in the following table:

	Units	Current	#3 Boiler Upgrade		150t/h 45bar Boiler		150t/h 80bar Boiler	
		Operations	49.5%	45%	49.5%	45%	49.5%	45%
Generator Loads								
New STG	MW		19.16	22.13	30.15	33.05	33.64	36.58
10 MW STG	MW	10.00	10.00	10.00	10.00	10.00	10.00	10.00
2 x 2.2MW STGs	MW	4.10	0.00	0.00	0.00	0.00	0.00	0.00
5.3MW STG	MW	4.90	0.70	0.70	0.90	0.90	0.90	0.90
Total	MW	19.00	29.86	32.83	41.05	43.95	44.54	47.48
Site Loads								
Current		9.00	9.00	9.00	9.00	9.00	9.00	9.00
Change:	MW							
- Reduce LP SOC	MW		0.00	-0.14	0.00	-0.14	0.00	-0.14
- #3 Boiler electric load	MW		0.71	0.71	0.00	0.00	0.00	0.00
- Shut #1 Boiler	MW		0.00	0.00	-0.35	-0.35	-0.35	-0.35
- New 150t/h boiler	MW		0.00	0.00	1.70	1.70	1.70	1.70
- New STG	MW		0.85	0.85	0.85	0.85	0.85	0.85
- Demin plant	MW		0.05	0.05	0.05	0.05	0.05	0.05
- Bagasse Handling	MW		0.00	0.00	0.05	0.05	0.05	0.05
Total	MW	9.00	10.61	10.47	11.30	11.16	11.30	11.16
Export								
Export to Grid	MW	10.00	19.25	22.36	29.75	32.79	33.24	36.32
Non-Crush								
Generation	MW		18.94	18.94				
Site Loads	MW		2.46	2.46				
Export	MW		16.48	16.48				
Export								
Q1 - Peak	MWh	0	0	0	0	0	0	0
- Offpeak	MWh	0	0	0	0	0	0	0
Q2 - Peak	MWh	2,252	4,471	5,223	6,918	7,653	7,730	8,473
- Offpeak	MWh	2,693	5,323	6,213	8,231	9,100	9,196	10,075
Q3 - Peak	MWh	9,266	18,451	21,573	28,578	31,627	31,936	35,018
- Offpeak	MWh	11,408	22,712	26,554	35,174	38,925	39,306	43,098
Q4 - Peak	MWh	2,095	16,377	17,074	6,418	7,098	7,171	7,859
- Offpeak	MWh	2,517	19,792	20,627	7,711	8,527	8,615	9,440
Total	MWh	30,231	87,126	97,264	93,030	102,930	103,954	113,963
Eligible Generation (RECs)								
Full year eligible generation	MWh	58,315	117,016	126,251	122,054	130,725	132,981	141,763
ORER Baseline	MWh	15,931	15,931	15,931	15,931	15,931	15,931	15,931
RECs		42,384	101,085	110,320	106,123	114,794	117,050	125,832

The total annual electricity export and RECs produced under current operations have been included as the Base Case. Points to note:

- The #3 Boiler upgrade option, at 45% LP SOC, generates more annual export power and RECs than the new boiler option at 49.5% SOC;
- The #3 Boiler upgrade options generate a much higher level of output in Quarter 4 (when pool prices are higher), than the new boiler options; and
- On TSL’s advice, TLF and DLF have been assumed to be unity.

Capital Costs

First order capital costs ($000) have been estimated as follows:

Options	#3 Boiler Upgrade		150t/h 45bar Boiler		150t/h 80bar Boiler	
SOC	49.5%	45%	49.5%	45%	49.5%	45%
Boiler						
New Superheater	1,200	1,200				
Steam pipe to STG	700	700				
New safety and isolation valves	500	500				
ID Fan drive electrification (VS)	700	700				
New Electric F'water pumps (VS x2)	1,200	1,200				
Deaerator	900	900				
STG						
22MW STG and condensor	9,200	9,200				
Civil works	800	800				
Building and crane	1,200	1,200				
Mechanical installation and pipework	3,200	2,800				
Electrical installation	2,800	3,200				
Cooling Tower, pumps and pipes	1,500	2,100				
LP Steam efficiency measures						
Pre-primary heater (#4 vapour)		1,000		1,000		1,000
#2 vapour to primary heaters		150		150		150
#1 vapour to A Contin. Pan		180		180		180
Upgrade primary juice pump		120		120		120
ESJ heater (#1 vapour)		400		400		400
Pressurised condensate (IP boilers)		625		625		625
Dedicated Evaporator for p/out steam	3,000	1,000	3,000	1,000	3,000	1,000
Water treatment						
Raw water storage tank	250	250	250	250	250	250
Demin plant and pumps	800	800	800	800	800	800
Polishing plant					300	300
Turnkey Project						
New Boiler; STG and Cooling Tower			80,000	80,000	90,000	90,000
Adjustment to MSL scope of work			-1,000	-1,000	-1,000	-1,000
Subtotal	27,950	29,025	83,050	83,525	93,350	93,825
Contingencies (5%)	1,398	1,451	4,153	4,176	4,668	4,691
Project Management /fees (8%)	2,236	2,322	6,644	6,682	7,468	7,506
Total	31,584	32,798	93,847	94,383	105,486	106,022

Points to note:

- The capital estimates for the new boiler options have been based on the indicative lump sum for the turn-key Racecourse power plant, which includes a similar sized boiler and STG. Adjustments have been made for differences such as grate type, no coal plant and feeders, full turbine hall and crane, modifications to bagasse feed belt, ducting to existing stack, different site preparation, etc;
- All 49.5% SOC options require a larger dedicated PE to condense the predicted 50 t/h pass-out steam, whereas the pass-out steam required for the 45% SOC options is about 20 t/h. It has been assumed that this could be accomplished with a small PHE

booster evaporator installed in parallel with #1 vessel, which would be significantly cheaper than a dedicated Roberts style evaporator;

- No capital allowance has been made to upgrade the existing 10MW 22kV interconnection with the grid. It is assumed that this would be provided by Ergon Energy and an annual generator charge has been included in the operating costs; and
- A Demin polishing plant has been added to the 80bar boiler option to cater for the higher feedwater quality standards.

Operating and Maintenance Costs

Figure 9 shows the operating and maintenance costs used in the financial analysis of each option. Some of these costs need to be confirmed by TSL and adjusted if necessary, particularly annual charges likely to be incurred from Ergon Energy for the larger capacity interconnection.

Annual maintenance costs on all new plant has been set at 1.0% of capital costs, and a maintenance saving of $0.25m pa has been credited to all new boiler options where #1 boiler has been decommissioned.

Bagasse handling costs have been included for the options where bagasse will be stored for non-crush operations, and tonnage rates supplied by TSL have been used. Non-crush labour costs for boiler operators has been based on 2 operators and 4 shifts for the duration of this activity.

Another issue that TSL needs to confirm is the payment by Ergon Energy for Avoided Transmission Use of System (ATUoS) for the export component of the project. This has been included at $3.50/MWh but this may not be the case for the Tully region, and can have a significant impact on revenue.

Project Power Purchase Agreement – Prices

Figure 10 shows the pricing structure that has been used in the analyses. The export component represents indicative forward market prices that MSL has recently obtained. This has been supplied on a quarterly and peak / off-peak basis so that the Cogen project can respond to price signals and maximize revenue from the limited bagasse fuel source. All modeling completed in this study assumes constant outputs, but different crop sizes and fibre levels (viz. bagasse supply) may dictate different peak and off-peak condenser loads to maximize revenue.

RECs have been priced at the new penalty value of $65 as proposed under the new 20%RET scheme. This revenue is available until YEJ 2031, the financial year in which the 20%RET scheme terminates. MSL is confident that the future REC prices will exceed this figure and move towards the tax-adjusted limit of $92, but it is considered prudent to use $65 at this point.

It has also been assumed that the TSL project will be commissioned for the 2013 crushing season, following a one year detailed feasibility study and a two year construction period.

Figure 9

General Operating and Maintenance Costs

HP boiler/demin plant chem/cons.	$ 50,000	pa	(Nalco estimate)
Administration	$ 60,000	pa	(Half-time Cogen manager, incl on-costs)
Ergon Generator charge	$ 420	per day	
Ergon Load charge	$ -	pa	(needs to be checked with Ergon if it will change)
Ergon Avoided TUoS p'ment -project	$ 3.50	/MWh	(needs to be checked with Ergon)
- current	$ -	/MWh	(currently paid??)
#1 Boiler maintenance savings	$ 250,000	pa	(only for new boiler options)
Maintenance costs on new plant	1.0%	Capital	
Bagasse (non-crush):			
Currently used at end-of-crush	10,000	tonne	]
Cogen end-of crush	61,000	tonne	] predicted
Cart to pad	$ 1.21	/tonne	]
Return from pad	$ 2.90	/tonne	]
Truck maintenance	$ 10,000	pa	] Only applies to current operations and Upgrade #3 boiler option
Pad maintenance	$ 15,000	pa	]
Tarp replacement	$ 5,000	pa	]
Labour (non-crush):			
Current end-of-crush period	1.0	wks	
Cogen end-of crush	10.0	wks	(predicted)
Operators per shift	2		
Shifts	4		
Annual wages	$ 85,000		(includes on-costs)

Operating Costs

	Units	Current Operations	#3 Boiler Upgrade 49.5%	#3 Boiler Upgrade 45%	150t/h 45bar Boiler 49.5%	150t/h 45bar Boiler 45%	150t/h 80bar Boiler 49.5%	150t/h 80bar Boiler 45%
HP boiler/demin plant chem/cons.	($000)	0.0	50.0	50.0	50.0	50.0	50.0	50.0
Administration	($000)	0.0	60.0	60.0	60.0	60.0	60.0	60.0
Ergon Generator charge	($000)	0.0	153.3	153.3	153.3	153.3	153.3	153.3
Ergon Load charge	($000)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ergon Avoided TUoS payment	($000)	In DCF worksheet						
#1 Boiler maintenance savings	($000)	0.0	0.0	0.0	-250.0	-250.0	-250.0	-250.0
Maintenance costs on new plant	($000)	0.0	293.5	304.8	872.0	877.0	980.2	985.2
Bagasse (non-crush):	($000)	66.1	280.7	280.7	0.0	0.0	0.0	0.0
Labour (non-crush):	($000)	13.1	130.8	130.8	0.0	0.0	0.0	0.0
Total	($000)	79.2	968.3	979.5	885.3	890.3	993.5	998.5

Figure 10

Electricity and REC Prices ($/MWh)

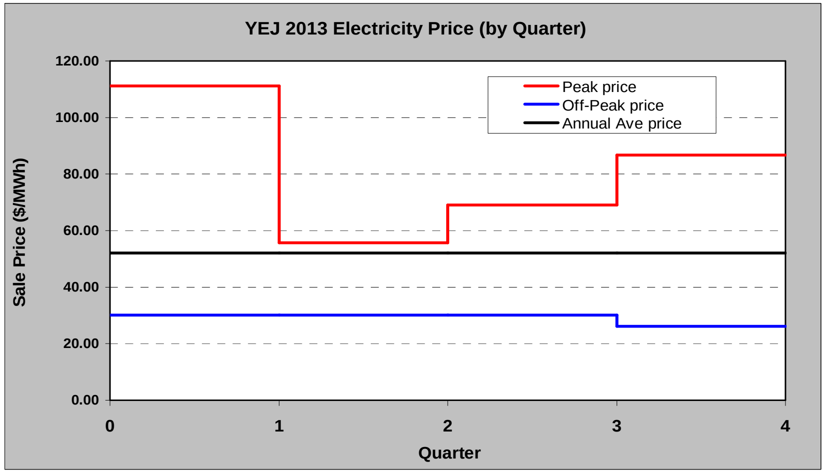
Final year of 20%RET 2030 (Calender year)

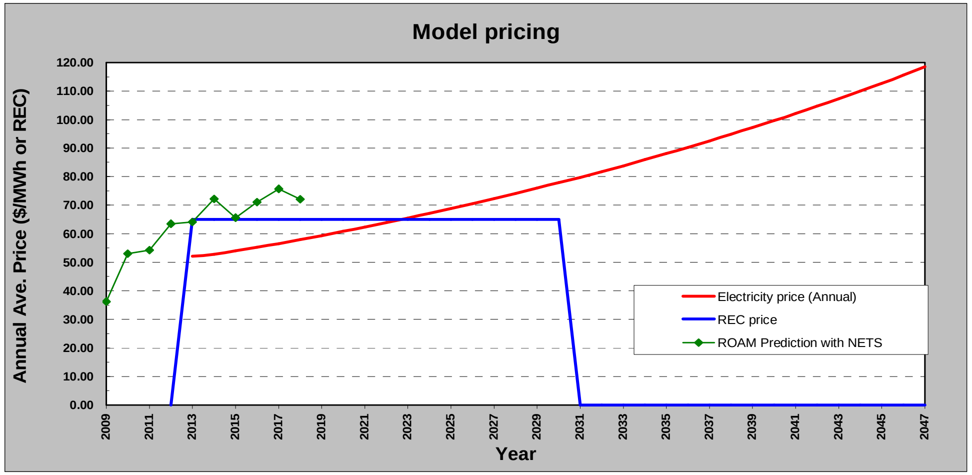
Contract Prices

		Price Adjustment	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	Annual Percentage Change								
		Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2013	2014	2015	2016	2017	2018	2019	2020	2021
Electricity	Q1	Peak	111.26	111.26	114.05	116.89	119.81	122.82					0.0%	2.5%	2.5%	2.5%	2.5%				
		Off-Peak	30.04	30.04	30.79	31.56	32.35	33.16					0.0%	2.5%	2.5%	2.5%	2.5%				
	Q2	Peak	55.64	55.64	57.02	58.45	59.91	61.40					0.0%	2.5%	2.5%	2.5%	2.5%				
		Off-Peak	30.04	30.04	30.79	31.56	32.35	33.16					0.0%	2.5%	2.5%	2.5%	2.5%				
	Q3	Peak	68.99	68.99	70.70	72.47	74.28	76.14					0.0%	2.5%	2.5%	2.5%	2.5%				
		Off-Peak	30.04	30.04	30.79	31.56	32.35	33.16					0.0%	2.5%	2.5%	2.5%	2.5%				
	Q4	Peak	86.79	86.79	88.95	91.18	93.46	95.79					0.0%	2.5%	2.5%	2.5%	2.5%				
		Off-Peak	26.16	26.16	26.16	26.16	26.16	26.16					0.0%	0.0%	0.0%	0.0%	0.0%				
RECs				65.00	65.00	65.00	65.00	65.00					#DIV/0!	0.0%	0.0%	0.0%	0.0%				

Model Inputs

Period			Year (YEJ)																			
			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Electricity																						
Price Indexation - change		%							2.50%													
- actual		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Q1	Peak		111.26	111.26	114.05	116.89	119.81	122.82	125.89	129.04	132.26	135.57	138.96	142.43	145.99	149.64	153.39	157.22	161.15	165.18	169.31	173.54
	Off-Peak		30.04	30.04	30.79	31.56	32.35	33.16	33.99	34.84	35.71	36.60	37.52	38.46	39.42	40.40	41.41	42.45	43.51	44.60	45.71	46.85
Q2	Peak		55.64	55.64	57.02	58.45	59.91	61.40	62.94	64.51	66.12	67.77	69.47	71.21	72.99	74.81	76.68	78.60	80.56	82.58	84.64	86.76
	Off-Peak		30.04	30.04	30.79	31.56	32.35	33.16	33.99	34.84	35.71	36.60	37.52	38.46	39.42	40.40	41.41	42.45	43.51	44.60	45.71	46.85
Q3	Peak			68.99	68.99	70.70	72.47	74.28	76.14	78.04	79.99	81.99	84.04	86.15	88.30	90.51	92.77	95.09	97.47	99.90	102.40	104.96
	Off-Peak			30.04	30.04	30.79	31.56	32.35	33.16	33.99	34.84	35.71	36.60	37.52	38.46	39.42	40.40	41.41	42.45	43.51	44.60	45.71
Q4	Peak			86.79	86.79	88.95	91.18	93.46	95.79	98.18	100.64	103.16	105.73	108.38	111.09	113.86	116.71	119.63	122.62	125.68	128.83	132.05
	Off-Peak			26.16	26.16	26.16	26.16	26.16	26.16	26.81	27.48	28.17	28.88	29.60	30.34	31.10	31.87	32.67	33.49	34.32	35.18	36.06
Time-weighted Annual Price				52.10	52.78	54.00	55.26	56.56	57.88	59.33	60.81	62.33	63.89	65.48	67.12	68.80	70.52	72.28	74.09	75.94	77.84	79.79
RECs																						
Price Indexation - change		%																				
- actual		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Q1			0.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	0.00
Q2			0.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	0.00
Q3				0.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Q4				0.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00





Financial Analysis

A simple discounted cash flow has been done for each option over a 30 year project life. Project outputs have been discounted by the current TSL cogeneration outputs, to assess the true return on the capital investment. Operating and maintenance costs have been inflated at 2.0%.

Cash flows and returns for the first 10 years for each option are shown in the following figures:

Figure 11: Options A and B (upgrade #3 boiler)
Figure 12: Options C and D (new 45 barg boiler)
Figure 13: Options E and F (new 80 barg boiler)

The results are summarized in the following table:

Option	Description			Export	Capital	Net	Project
	Boiler	STG	LP SOC		Estimate	Cashflow	IRR
				(MW)	($m)	($m /pa)	(%)
A	Upgrade #3 Boiler to 45barg	New 22MW Conden./extract.STG	49.5%	19.3	31.6	6.07	17.93%
B	Upgrade #3 Boiler to 45barg	New 22MW Conden./extract.STG	45%	22.4	32.8	7.18	20.35%
C	New 140t/h 45bar Boiler; Shut #1	New 33MW Conden./extract.STG	49.5%	29.8	93.8	6.63	5.13%
D	New 140t/h 45bar Boiler; Shut #1	New 33MW Conden./extract.STG	45%	32.8	94.4	7.69	6.60%
E	New 140t/h 80bar Boiler; Shut #1	New 36MW Conden./extract.STG	49.5%	33.2	105.5	7.78	5.56%
F	New 140t/h 80bar Boiler; Shut #1	New 36MW Conden./extract.STG	45%	36.3	106.0	8.86	6.86%

Figure 11

Option	Inputs		YEJ												
	Inputs		2011	2012	**2013**	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Inflation index		*1.000*	*1.020*	*1.040*	*1.061*	*1.082*	*1.104*	*1.126*	*1.149*	*1.172*	*1.195*	*1.219*	*1.243*	*1.268*
A	**Upgrade #3 Boiler; 49.5% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-15,791.8	-15,791.8	0.0									
	Revenue														
	Project - Export	$000				4,313.2	4,407.6	4,505.0	4,604.7	4,706.8	4,824.5	4,945.1	5,068.7	5,195.4	5,325.3
	- RECs	$000				6,570.5	6,570.5	6,570.5	6,570.5	6,570.5	6,570.5	6,570.5	6,570.5	6,570.5	6,570.5
	- Avoided TUoS	$000				323.6	330.1	336.7	343.4	350.3	357.3	364.4	371.7	379.2	386.7
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	7,011.4	7,078.1	7,146.8	7,217.1	7,289.1	7,374.1	7,461.3	7,550.6	7,642.2	7,735.9
	O&M Costs														
	Project	$000				1,027.5	1,048.1	1,069.0	1,090.4	1,112.2	1,134.5	1,157.2	1,180.3	1,203.9	1,228.0
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	943.5	962.4	981.6	1,001.2	1,021.3	1,041.7	1,062.5	1,083.8	1,105.5	1,127.6
	Net Cash Flow (EBITDA)	$000	0.0	-15,791.8	-15,791.8	6,067.9	6,115.7	6,165.2	6,215.8	6,267.8	6,332.5	6,398.8	6,466.9	6,536.7	6,608.4
	30 year Project Life:	**IRR**	**17.93%**												
B	**Upgrade #3 Boiler; 45% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-16,399.1	-16,399.1	0.0									
	Revenue														
	Project - Export	$000				4,796.6	4,902.5	5,011.7	5,123.5	5,238.1	5,369.1	5,503.3	5,640.9	5,781.9	5,926.4
	- RECs	$000				7,170.8	7,170.8	7,170.8	7,170.8	7,170.8	7,170.8	7,170.8	7,170.8	7,170.8	7,170.8
	- Avoided TUoS	$000				361.3	368.5	375.9	383.4	391.0	398.9	406.8	415.0	423.3	431.7
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	8,132.7	8,211.7	8,293.0	8,376.2	8,461.4	8,560.6	8,662.2	8,766.3	8,873.0	8,982.3
	O&M Costs														
	Project	$000				1,039.5	1,060.3	1,081.5	1,103.1	1,125.2	1,147.7	1,170.6	1,194.1	1,217.9	1,242.3
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	955.5	974.6	994.1	1,014.0	1,034.2	1,054.9	1,076.0	1,097.5	1,119.5	1,141.9
	Net Cash Flow (EBITDA)	$000	0.0	-16,399.1	-16,399.1	7,177.2	7,237.1	7,298.9	7,362.2	7,427.2	7,505.7	7,586.2	7,668.8	7,753.5	7,840.4
	30 year Project Life:	**IRR**	**20.35%**												

Figure 12

Option	Inputs		YEJ												
	Inputs		2011	2012	**2013**	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Inflation index		*1.000*	*1.020*	*1.040*	*1.061*	*1.082*	*1.104*	*1.126*	*1.149*	*1.172*	*1.195*	*1.219*	*1.243*	*1.268*
C	**New 45bar Boiler; 49.5% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-46,923.3	-46,923.3	0.0									
	Revenue														
	Project - Export	$000				4,434.9	4,540.2	4,648.8	4,759.9	4,873.9	4,995.8	5,120.7	5,248.7	5,379.9	5,514.4
	- RECs	$000				6,898.0	6,898.0	6,898.0	6,898.0	6,898.0	6,898.0	6,898.0	6,898.0	6,898.0	6,898.0
	- Avoided TUoS	$000				345.5	352.4	359.5	366.7	374.0	381.5	389.1	396.9	404.8	412.9
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	7,482.5	7,560.5	7,640.9	7,723.1	7,807.4	7,897.1	7,989.1	8,083.3	8,179.8	8,278.7
	O&M Costs														
	Project	$000				939.5	958.3	977.5	997.0	1,017.0	1,037.3	1,058.0	1,079.2	1,100.8	1,122.8
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	855.5	872.6	890.1	907.9	926.0	944.5	963.4	982.7	1,002.3	1,022.4
	Net Cash Flow (EBITDA)	$000	0.0	-46,923.3	-46,923.3	6,627.0	6,687.9	6,750.8	6,815.2	6,881.4	6,952.6	7,025.7	7,100.6	7,177.5	7,256.3
	30 year Project Life:	**IRR**	**5.13%**												
D	**New 45bar Boiler; 45% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-47,191.6	-47,191.6	0.0									
	Revenue														
	Project - Export	$000				4,906.9	5,023.5	5,143.6	5,266.6	5,392.8	5,527.6	5,665.8	5,807.4	5,952.6	6,101.4
	- RECs	$000				7,461.6	7,461.6	7,461.6	7,461.6	7,461.6	7,461.6	7,461.6	7,461.6	7,461.6	7,461.6
	- Avoided TUoS	$000				382.3	390.0	397.8	405.7	413.8	422.1	430.5	439.1	447.9	456.9
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	8,554.9	8,644.9	8,737.6	8,832.4	8,929.6	9,033.1	9,139.2	9,247.9	9,359.2	9,473.3
	O&M Costs														
	Project	$000				944.8	963.7	983.0	1,002.6	1,022.7	1,043.1	1,064.0	1,085.3	1,107.0	1,129.1
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	860.8	878.0	895.6	913.5	931.7	950.4	969.4	988.8	1,008.5	1,028.7
	Net Cash Flow (EBITDA)	$000	0.0	-47,191.6	-47,191.6	7,694.1	7,766.9	7,842.0	7,918.9	7,997.9	8,082.8	8,169.8	8,259.1	8,350.6	8,444.5
	30 year Project Life:	**IRR**	**6.60%**												

Figure 13

Option	Inputs		2011	2012	**2013**	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			YEJ												
		Inflation index	*1.000*	*1.020*	*1.040*	*1.061*	*1.082*	*1.104*	*1.126*	*1.149*	*1.172*	*1.195*	*1.219*	*1.243*	*1.268*
E	**New 80bar Boiler; 49.5% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-52,742.8	-52,742.8	0.0									
	Revenue														
	Project - Export	$000				4,955.7	5,073.4	5,194.7	5,318.9	5,446.3	5,582.5	5,722.0	5,865.1	6,011.7	6,162.0
	- RECs	$000				7,608.3	7,608.3	7,608.3	7,608.3	7,608.3	7,608.3	7,608.3	7,608.3	7,608.3	7,608.3
	- Avoided TUoS	$000				386.1	393.8	401.7	409.7	417.9	426.3	434.8	443.5	452.4	461.4
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	8,754.1	8,845.3	8,939.3	9,035.4	9,134.0	9,238.9	9,346.4	9,456.5	9,569.4	9,685.1
	O&M Costs														
	Project	$000				1,054.3	1,075.4	1,096.9	1,118.8	1,141.2	1,164.0	1,187.3	1,211.0	1,235.3	1,260.0
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	970.3	989.7	1,009.5	1,029.6	1,050.2	1,071.2	1,092.7	1,114.5	1,136.8	1,159.6
	Net Cash Flow (EBITDA)	$000	0.0	-52,742.8	-52,742.8	7,783.9	7,855.7	7,929.8	8,005.7	8,083.7	8,167.6	8,253.7	8,342.0	8,432.6	8,525.5
	30 year Project Life:	**IRR**	**5.56%**												
F	**New 80bar Boiler; 45% SOC**														
	Capital														
	Total capital cash flow	$000	0.0	-53,011.1	-53,011.1	0.0									
	Revenue														
	Project - Export	$000				5,432.9	5,562.0	5,695.0	5,831.1	5,970.9	6,120.1	6,273.1	6,430.0	6,590.7	6,755.5
	- RECs	$000				8,179.1	8,179.1	8,179.1	8,179.1	8,179.1	8,179.1	8,179.1	8,179.1	8,179.1	8,179.1
	- Avoided TUoS	$000				423.3	431.8	440.4	449.2	458.2	467.3	476.7	486.2	495.9	505.9
	Current - Export	$000				1,441.0	1,475.2	1,510.4	1,546.5	1,583.6	1,623.2	1,663.8	1,705.4	1,748.0	1,791.7
	- RECs	$000				2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0	2,755.0
	- Avoided TUoS	$000				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net Revenue	$000	0.0	0.0	0.0	9,839.4	9,942.7	10,049.1	10,157.9	10,269.6	10,388.4	10,510.2	10,634.9	10,762.8	10,893.8
	O&M Costs														
	Project	$000				1,059.6	1,080.8	1,102.4	1,124.4	1,146.9	1,169.9	1,193.3	1,217.1	1,241.5	1,266.3
	Current	$000				84.0	85.7	87.4	89.2	90.9	92.8	94.6	96.5	98.4	100.4
	Net Costs	$000	0.0	0.0	0.0	975.6	995.1	1,015.0	1,035.3	1,056.0	1,077.1	1,098.6	1,120.6	1,143.0	1,165.9
	Net Cash Flow (EBITDA)	$000	0.0	-53,011.1	-53,011.1	8,863.8	8,947.6	9,034.1	9,122.6	9,213.6	9,311.3	9,411.5	9,514.3	9,619.8	9,727.9
	30 year Project Life:	**IRR**	**6.86%**												

Discussion

The results highlight the difficulty in justifying a new HP boiler for Cogeneration, unless it also operates for the bulk of the non-crush (to access the high Q1 pool prices), or it's installation is needed for the sugar factory operation and capital costs can be partially supported by sugar revenue. This has been a common finding in bagasse cogeneration feasibility studies.

The upgrade of #3 Boiler to 45 barg, installation of a 22MW condensing / extraction STG and the improvement of the factory LP steam efficiency to 45% SOC, appears to be an attractive project for TSL. It would certainly be the preferred Cogeneration project that offers best returns for TSL.

Figures 14 and 15 show the crushing season HP steam and LP steam/condensate flowsheets for this project, while Figure 16 indicates the project outputs by quarter. Non-crush operations are depicted in Figures 7 and 8.

Further enhancements to the project include a STG condensate reheater using vapour from #2 effets, and a pressurized feedwater system for #1 and #2 boiler return condensates. The condensate reheater reduces STG pass-out steam and will add about 0.5MW to the STG output during the crush, while the pressurized condensate system will save about 13,000 tonne of bagasse. The latter will extend the non-crush operations by about 2 weeks.

Project Development

If TSL wishes to pursue this project, it is recommended that a two stage development program be adopted: a pre-feasibility study to more accurately scope and cost the project, followed by a detailed feasibility study to prepare a Project Plan for Board approval.

The project development (excluding finance) can be broken into six main components:

1. Power plant: #3 boiler upgrade, 22MW STG, export transformer, cooling tower, auxiliary drive electrification, deaerator and demin plant, all interconnecting pipework, and electrical work.
2. Process plant: Modifications to effets/heaters to reach 45% SOC, dedicated PE for pass-out steam, pressurized condensate system.
3. Electrical: Connection of the STG to the factory HV distribution.
4. Interconnection: Upgrade interconnection to Ergon network, including NEM compliance.
5. PPA: Contract for off-take of electricity and RECs
6. Statutory: Council, EPA, water, etc

The following management strategy is suggested.

Pre-feasibility study

A Project Manager needs to be dedicated to overseeing the various components of the study. TSL may undertake this role, or an experienced project manager from an engineering consultant such as WorleyParsons, Connell Hatch or SKM could be engaged. iPower would also be capable here. If a consultant is engaged, is it essential that their role is accurately defined and that they do not undertake full engineering of all components that could be more cost-effectively done by others listed below.

To better define the work scope, capital estimates, project inputs and project outputs, it is suggested that the following contractors be engaged on a fee paying basis for each component of the project:

Power plant:
AE&E (old Alstom) would be the logical contractor as they were the original boiler manufacturer. AE&E would do preliminary engineering of the full power plant, including general layout drawings, heat balance modeling, steam process flowsheets, STG and cooling tower sizing, and second order capital estimating

Process plant:
SRI should review report #3215 and confirm the scope of the LP steam efficiency plant. This information can be transferred directly to WDT Engineers or Bundaberg Foundry for general layout drafting and second-order estimating, or alternatively, could be sent to Process Essentials (ex STG, Bris) to do this work. Process Essentials would add a layer of engineering over the project that could more effectively interface the Power Plant with the Process Plant

Electrical:
TSL would have the best knowledge of an Electrical consultant that could complete this work. MSL has been using Logicamms (ex Patterson Flood) who have excellent experience in this area.

Interconnection:
TSL may deal directly with Ergon, or use Hill Michael and Associates (HMA, Townsville) as MSL has done.

PPA:
TSL may control this directly, or could use HMA, Distributed Power, or others. There is merit in considering other counterparties besides electricity Retailers.

Statutory:
TSL could manage this, with the assistance of the Project Manager.

An important issue to be resolved at this stage of the study is the bagasse balance. It is suggested that SRI be engaged to carry out boiler efficiency studies on each boiler this season, and random bagasse samples should be sent to SGS for ultimate analysis and determination of calorific value. A better understanding of the bagasse consumption during mill train stoppages would also be beneficial. An accurate assessment of surplus bagasse quantities will dictate the duration of non-crush operations and resulting revenue.

Feasibility Study

Subject to a satisfactory result from the pre-feasibility study, the full feasibility study could be undertaken under the same project management structure.

Power Plant:
For this stage, it is suggested that an alliance be considered with AE&E and a detailed specification and contract document be prepared under an open-book arrangement. This would include a lump sum price for the turn-key power plant. If the project is approved, AE&E are guaranteed the contract, so they should be prepared to develop the specification/contract document at no cost.

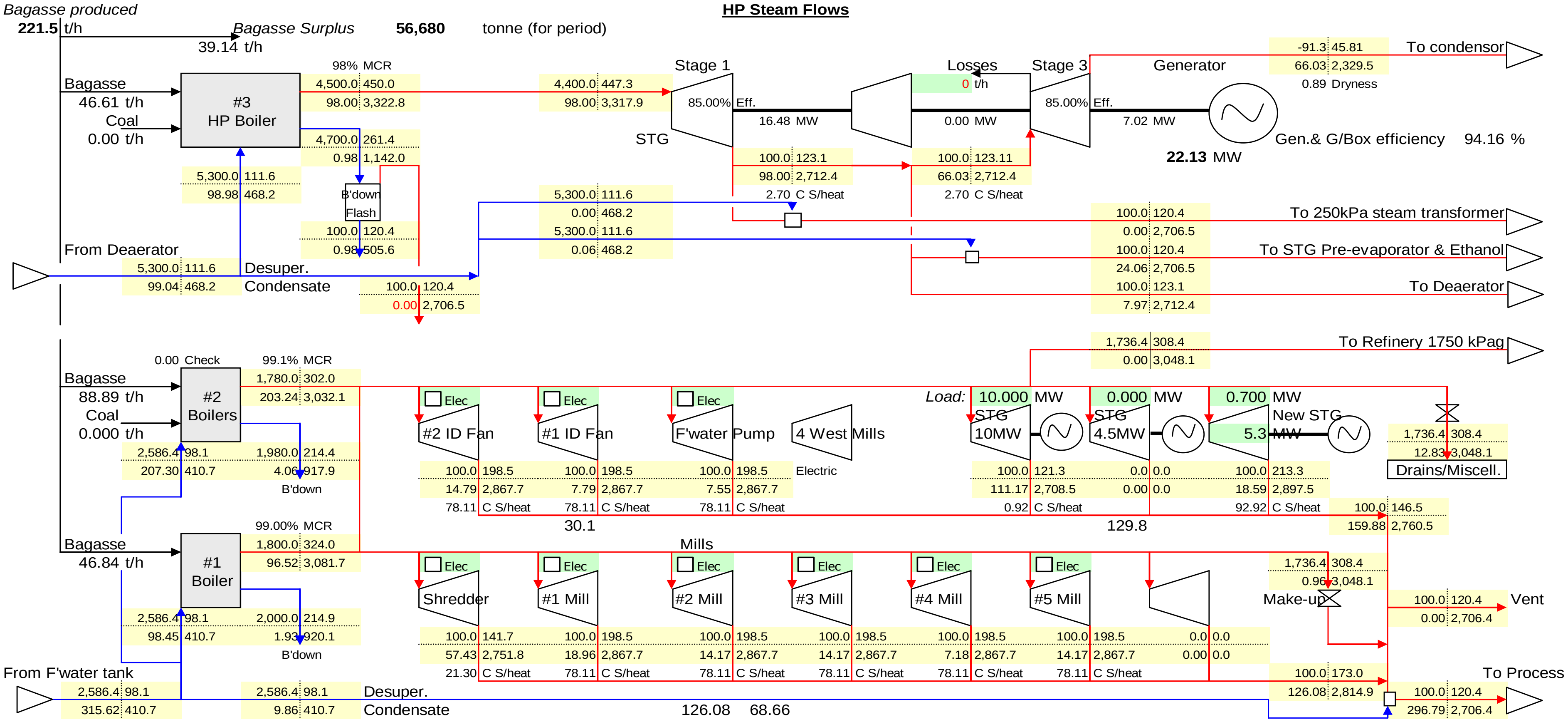
Process Plant:
If a consultant like Process Essentials is used, they would prepare detailed specifications and call tenders for a lump sum contract (e.g. from WDT, Bundaberg Foundry, Bilfinger Berger, G&S, etc). Alternatively, an alliance could be struck with one of these construction companies to jointly undertake the engineering design, drafting, specification preparation and supply of a lump sum price.

Electrical:
The consultant would prepare a specification for all electrical work outside of the AE&E power plant contract termination points, and call tenders for a lump sum contract.

Interconnection:
An "Application to Connect" would be submitted to Ergon, who will respond with an "Offer to Connect". This would detail annual Generator and Load charges, and security requirements. Confirmation is also needed that the generator complies with NEM standards.

PPA:
PPA negotiations would result in counter-party term sheets and a draft contract ready for acceptance.

Figure 14



Boiler data:

	#3	#2	#1	
Pressure	4,500	1,780	1,800	kPag
Temperature	450	302	324	°C
MCR	100	205	97.5	t/h
Effic. -Bagasse	67.0%	67.0%	61.5%	(50% moist.)
-Coal	80%	70%		
Blowdown	1.0%	2.0%	2.0%	steam flow
Steam flow	98.0			t/h
#2 & #3 loads		68%	32.2%	% IP load
Fuel mix	100%	100%	100%	Bagasse (by energy)
FSL (ORER)		0.00%		(fossil fuel ratio)
Ash make	2.35	4.49	2.37	t/h (@60% m.)

Fuel data:

Crush rate		713	TCH
Crop		2,000.7	kt
Analysis period		19.220	weeks
Lost time		13.10%	available
Cane fibre		15.78%	(15,15.78,16.5)
Mud/Cane		6.05%	
Fibre/Mud		7.08%	
Bagasse:	Moist.	49.50%	wet basis
	Pol	1.83%	dry basis
	Ash	4.0%	dry basis
	Corr.factor	0.0%	extra consumption
Coal:	GCV	24,537	kJ/kg
	Ash	7.77%	as fired

STG data:

	Stage 1	Stage 2	Stage 3	
Design flow	98.0	98.0	70.0	t/h
Minimum Stage 3 flow	5%			design flow
Condensing pressure	10.00			kPaA
Generator capacity	22.0			MW
Gearbox efficiency	98.0%			

General data:

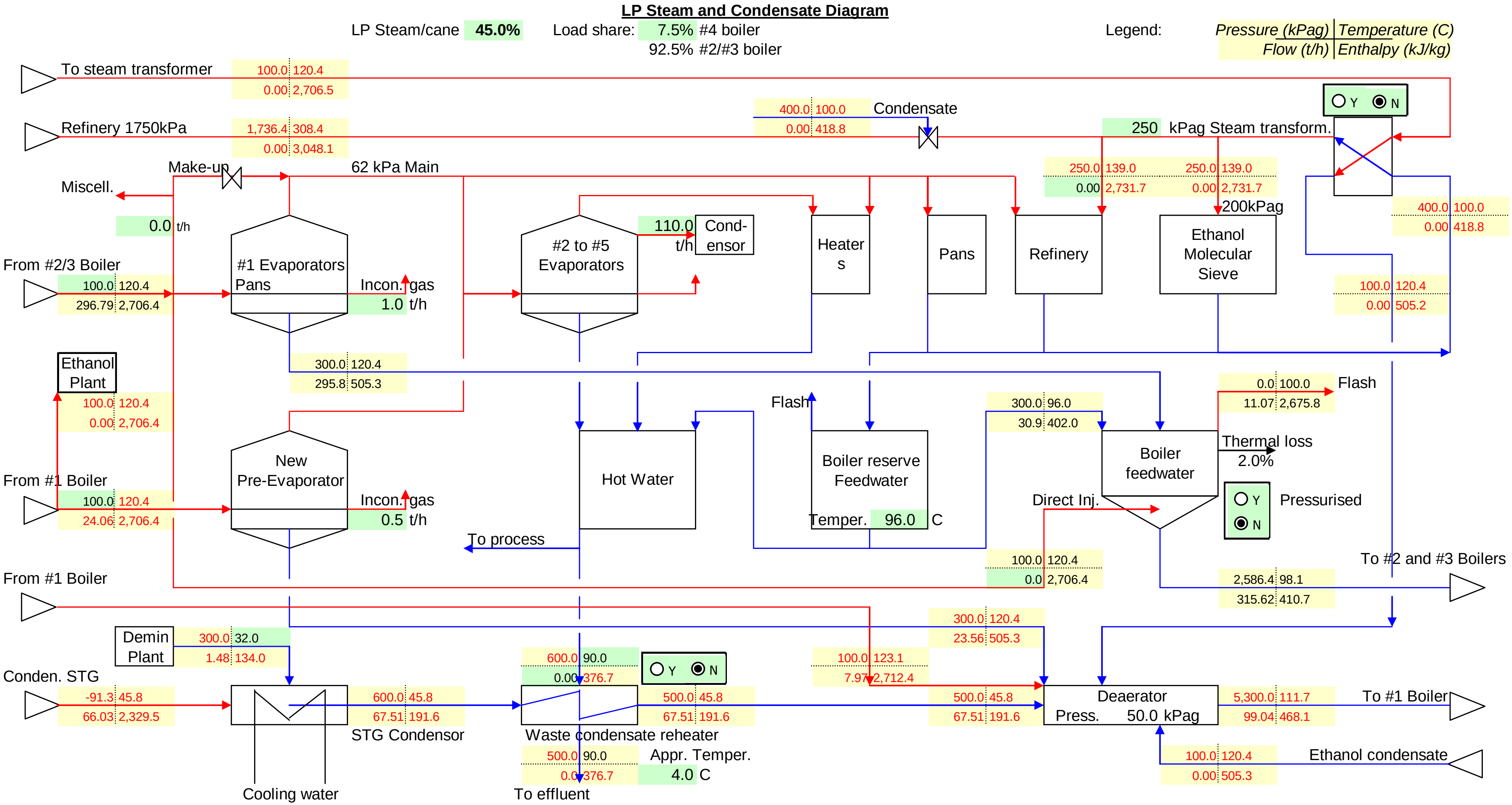
Miscell IP steam flow	1.8%	Cane
HP pipe pressure loss	100.0	kPag
IP pipe pressure loss	50.0	kPag
Deaerator pressure	50.0	kPag
Total generation	32.83	MW
Total site load	10.472	MW
Export	22.361	MW

Legend:

Pressure (kPag)	*Temperature (C)*
Flow (t/h)	*Enthalpy (kJ/kg)*

2

Figure 15



LP Steam and Condensate Diagram
LP Steam/cane 45.0%
Load share: 7.5% #4 boiler
92.5% #2/#3 boiler
Legend:
Pressure (kPag) | Temperature (C)
Flow (t/h) | Enthalpy (kJ/kg)
To steam transformer
100.0 120.4
0.00 2,706.5
Refinery 1750kPa
1,736.4 308.4
0.00 3,048.1
400.0 100.0
0.00 418.8
Condensate
250 kPag Steam transform.
Y N
Make-up
62 kPa Main
Miscell.
0.0 t/h
250.0 139.0
0.00 2,731.7
250.0 139.0
0.00 2,731.7
200kPag
400.0 100.0
0.00 418.8
From #2/3 Boiler
100.0 120.4
296.79 2,706.4
#1 Evaporators Pans
Incon. gas
1.0 t/h
#2 to #5 Evaporators
110.0 t/h
Cond-ensor
Heaters
Pans
Refinery
Ethanol Molecular Sieve
100.0 120.4
0.00 505.2
Ethanol Plant
100.0 120.4
0.00 2,706.4
300.0 120.4
295.8 505.3
0.0 100.0
11.07 2,675.8
Flash
Flash
300.0 96.0
30.9 402.0
New Pre-Evaporator
Incon. gas
0.5 t/h
Hot Water
Boiler reserve Feedwater
Temper. 96.0 C
Boiler feedwater
Thermal loss
2.0%
Direct Inj.
Y N
Pressurised
From #1 Boiler
100.0 120.4
24.06 2,706.4
To process
100.0 120.4
0.0 2,706.4
To #2 and #3 Boilers
2,586.4 98.1
315.62 410.7
From #1 Boiler
300.0 120.4
23.56 505.3
Demin Plant
300.0 32.0
1.48 134.0
600.0 90.0
0.00 376.7
Y N
100.0 123.1
7.97 2,712.4
Conden. STG
-91.3 45.8
66.03 2,329.5
600.0 45.8
67.51 191.6
STG Condensor
500.0 45.8
67.51 191.6
500.0 45.8
67.51 191.6
Deaerator
Press. 50.0 kPag
5,300.0 111.7
99.04 468.1
To #1 Boiler
Waste condensate reheater
500.0 90.0
0.0 376.7
Appr. Temper.
4.0 C
100.0 120.4
0.00 505.3
Ethanol condensate
Cooling water
To effluent

Figure 16

Financial Summary (Crushing season)

Season length	19.22	weeks	97.0%	Plant availability	Ethanol Plant	N	(Y or N)	Fibre	A	(H,A or L)	Scheme M (M or Q)
Crop	2,000,654	tonne	*Description:*	**713TCH; Upgrade #3 Boiler to 45bar; New 22MW Condensing extraction STG; 45% LP SOC**							

Parameter		Current Mode			Cogeneration Mode												
		1	2	Total	4		4		5		5		6		6		Total
Crushing rate	TCH				713		713		713		713		713		713		
LP steam/cane	%				45.0%		45.0%		45.0%		45.0%		45.0%		45.0%		
Period	wks				1.43		1.71		5.89		7.25		1.34		1.60		19.22
Lost time	%				13.1%		13.1%		13.1%		13.1%		13.1%		13.1%		
Crushing time	hrs				208.6		250.2		860.3		1,058.4		195.5		232.9		
Peak (P), Off-peak (O), Flat (F)					P		O		P		O		P		O		
Export price	$/MWh				63.03		33.54		63.92		31.19		95.69		31.19		
Boiler No.					#3	#1/#2	#3	#1/#2	#3	#1/#2	#3	#1/#2	#3	#1/#2	#3	#1/#2	
Boiler load	t/h				98.00	299.76	98.00	299.76	98.00	299.76	98.00	299.76	98.00	299.76	98.00	299.76	
STG condensor flow	t/h				66.03	0.00	66.03	0.00	66.03	0.00	66.03	0.00	66.03	0.00	66.03	0.00	
Site electrical loads:	kW																
Base Factory Load	kW					9,000.0		9,000.0		9,000.0		9,000.0		9,000.0		9,000.0	
Reduce LP SOC to 45%	kW					-135.0		-135.0		-135.0		-135.0		-135.0		-135.0	
Upgrade #3 boiler to 45bar	kW					710.0		710.0		710.0		710.0		710.0		710.0	
Shut #1 Boiler	kW					0.0		0.0		0.0		0.0		0.0		0.0	
New 150t/h Boiler	kW				0.0		0.0		0.0		0.0		0.0		0.0		
New STG	kW				847.0		847.0		847.0		847.0		847.0		847.0		
Demin Plant	kW				50.0		50.0		50.0		50.0		50.0		50.0		
Bagasse handling increase	kW				0.0		0.0		0.0		0.0		0.0		0.0		
Total	MW				0.897	9.575	0.897	9.575	0.897	9.575	0.897	9.575	0.897	9.575	0.897	9.575	
Total	MW					10.472		10.472		10.472		10.472		10.472		10.472	
Generation - while crushing	MW				22.133	10.700	22.133	10.700	22.133	10.700	22.133	10.700	22.133	10.700	22.133	10.700	
- while not crushing	MWh					942.9		1,058.7		3,946.7		4,870.4		815.4		1,039.6	
Export - while crushing	MW					22.361		22.361		22.361		22.361		22.361		22.361	
- while not crushing	MWh					719.4		809.5		3,003.0		3,707.4		621.4		794.5	
Bagasse - surplus while crushing	t/h					39.14		39.14		39.14		39.14		39.14		39.14	
- used while not crushing	tonne					3,962.5		4,581.6		16,378.2		20,209.7		3,533.2		4,419.3	
Coal	t/h				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Boiler make-up water	t/h				1.5	0.0	1.5	0.0	1.5	0.0	1.5	0.0	1.5	0.0	1.5	0.0	
Ash cartage	t/h				2.35	6.85	2.35	6.85	2.35	6.85	2.35	6.85	2.35	6.85	2.35	6.85	
ORER: - Fossil fuel ratio (FSL)	%					0.00%		0.00%		0.00%		0.00%		0.00%		0.00%	
- Non eligible aux (AUX)	MW				1.414	0.133	1.414	0.133	1.414	0.133	1.414	0.133	1.414	0.133	1.414	0.133	
Export - energy (adjusted)	MWh			0		5,223		6,213		21,573		26,554		4,843		5,821	**70,226**
- revenue	$			0		329,191		208,370		1,378,961		828,204		463,397		181,566	3,389,690
RECs - TLEG	MWh				5,247	2,383	6,235	2,847	21,686	9,837	26,692	12,105	4,861	2,222	5,846	2,658	
- AUX	MWh				286	28	343	33	1,180	114	1,452	141	268	26	319	31	
- FSL	MWh					0.0		0.0		0.0		0.0		0.0		0.0	
- Eligible generation				0		7,316		8,705		30,228		37,203		6,789		8,153	**98,394**
- revenue	$			0		365,800		435,250		1,511,400		1,860,150		339,450		407,650	4,919,700
Bagasse stockpiled	tonne			**0**		4,456		5,515		18,337		22,499		4,355		4,977	**60,138**
Coal consumed	tonne			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler treated make-up water	tonne			0.0	299.5	0.0	359.2	0.0	1,235.1	0.0	1,519.5	0.0	280.6	0.0	334.3	0.0	4,028.2
Ash cartage	tonne			0	476.3	1,430.0	571.3	1,715.2	1,964.1	5,897.0	2,416.4	7,254.9	446.3	1,339.9	531.6	1,596.1	25,639
Revenue - Export	$			0									3,389,690				3,389,690
- RECs	$			0									4,919,700				4,919,700