Biomass Cogeneration in the Southwest Timber hub

Pre-feasibility Assessment

Document Information

CURRENT DOCUMENT STATUS	
Revision Number	2
Delivery Date	17/5/21
Authors	Karne de Boer and Shayne Murphy
Description	Pre-feasibility assessment of biomass cogeneration for the South West Timber Hub

REVISION HISTORY			
Revision	**Description of Change**	**Changed By**	**Effective Date**
0	Issued for Internal Review	Karne de Boer	26/3/21
1	Issued for client review	Shayne Murphy	26/3/21
2	Update to way forward section after discussion	Karne de Boer	17/5/21

Contents

Introduction

The Moore Rd Timber precinct located in Dardanup, WA incorporates a number of large processors that transform fibre resources into a wide range of valuable products.

These processes are energy intensive and there is potential to utilise locally available biomass to generate green heat and power to improve the carbon footprint and long-term viability of these industries.

In view of this opportunity, the South West Timber Hub engaged Enerbi to undertake a pre-feasibility assessment of bioenergy cogeneration in the Moore Rd Timber Precinct.

This report summarises the findings of this assessment work and provides a basis for further investigation into biomass cogeneration in this precinct.

Biomass Cogeneration

Cogeneration incorporates a range of technologies that generate electricity and heat simultaneously, as a result they are regularly referred to as Combined Heat and Power (CHP) plants.

Heat can take the form of hot water, steam, thermal oil or hot air and can be used for industrial heating (e.g.: drying) or domestic purposes (e.g.: district heating). Cogeneration technologies can utilise a range of fuels including natural gas (e.g.: gas turbine), coal, biomass or other fuels.

Cogeneration is particularly attractive because it increases the overall utilisation of energy available within a fuel as shown in Figure 1. That is, a traditional power plant is more efficient in regards to the generation of electricity but cogeneration is able to utilise more than twice the energy that was available in the fuel.

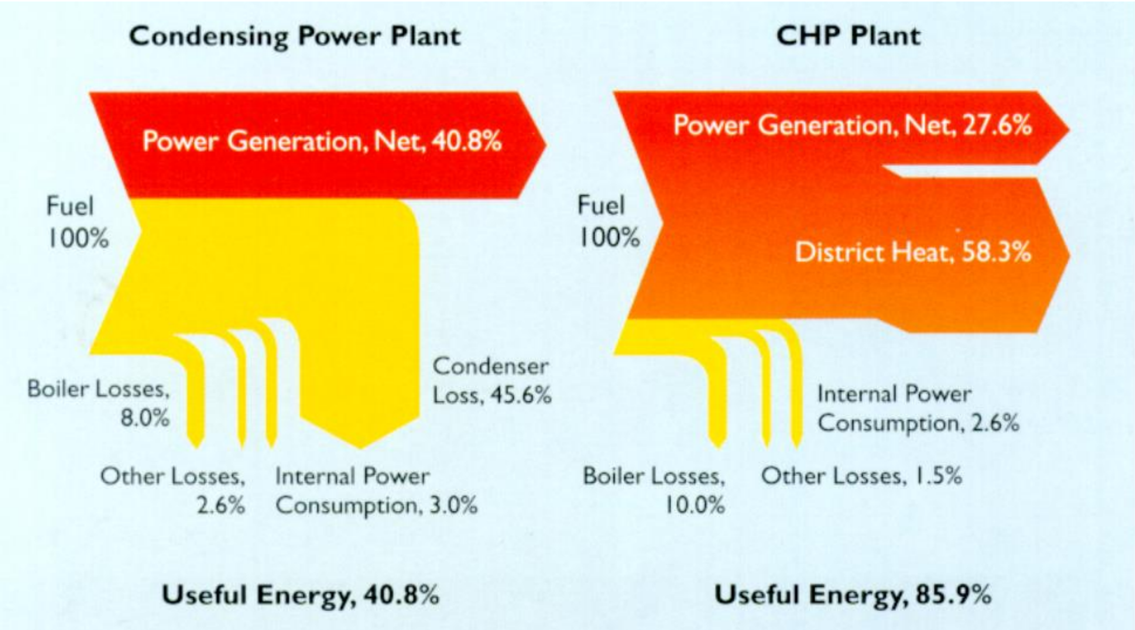


Figure 1: Comparison a traditional thermal power station and Combined Heat and Power (CHP)[1]

[1] https://tut.ee/public/s/Sustainable_Energetics/materials/Applications_of_Materials/Cogeneration-2012.pdf

Biomass cogeneration specifically involves the thermal transformation of biomass as a fuel into heat and power. Traditionally it has been widely used in industries that had limited energy options and excess quantities of biomass – e.g.: bagasse in the sugar industry, timber residues in sawmilling.

Moore Rd Precinct Opportunity

Biomass cogeneration represents a significant long-term investment and raising this capital requires a number of core elements to come together as shown in Figure 2.

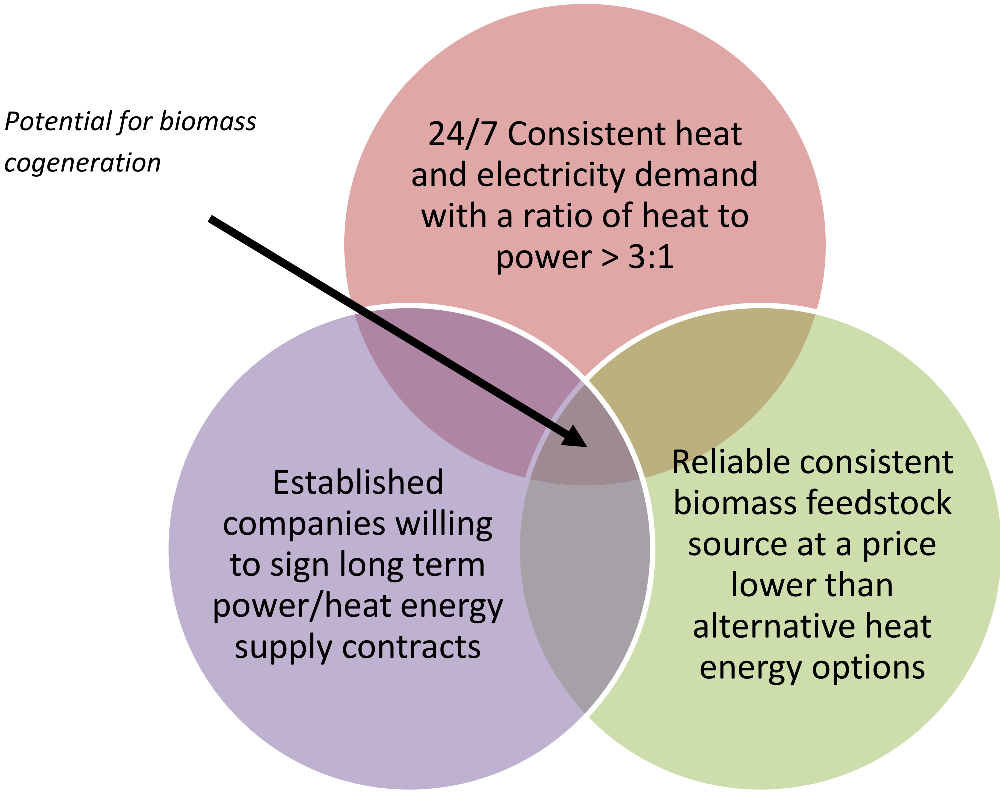


Figure 2: Requirements for successful biomass cogeneration project

In our experience the three conditions summarised in Figure 2 are a pre-requisite to justify the investment required for biomass cogeneration. If these three conditions are met it is likely that there will be favourable conditions for investment. In addition to these the following drivers also improve the business case for biomass cogeneration

- External pressure (legislation, market, consumer opinion) for potential energy users to reduce carbon; and
- Low grade heat demand (<100°C).

At face value the Moore rd Timber precinct possesses these 3 characteristics and the focus of this preliminary assessment is to understand if this potential could lead to a viable project.

Review of the Moore Rd Precinct Opportunity

Location / Energy Users

The Moore rd Timber Precinct includes the following companies:

- Laminex
- Hexion
- Wespine
- Preston chipping; and
- *Potentially WAPRES pellet mill to be located at Preston Chipping site*

Currently, Laminex and Wespine are the major energy users with consistent heat and power demands that run continuously throughout the year. These businesses use energy in the form of natural gas for heat production and grid electricity from the Western Power Network. The average use of electricity and heat is summarised in Table 1. The relative locations are shown in Figure 1 on the following page

Table 1: Summary of Energy use from stakeholders

	Average Electricity (MW_e)	**Peak Electricity (MW_e)**	**Average heat (MW_{th})**	**Heat to Average Electricity ratio**	**Temperature of heat**
Wespine[2]	2	3	11	~5	140°C
Laminex[3]	5.2	6	3.5	~0.7	180°C
WAPRES Stage 1[4]	3.1	3.3	9	~3	110°C
Hexion[5]		0.7	-		Steam
Preston chipping[6]		0.8	0		
Total	**10.3**	**13.8**	**23.5**	**1.7**	

Both Preston chipping and Hexion have relatively low and sporadic electricity (shift based) demands combined with zero or high temperature heat that will not improve the business case for cogeneration. From the outset these have been not been included in the analysis.

If the proposed WAPRES pellet mill (shown in grey) goes ahead (completion end of 2023) it represents another large energy user of both heat and electricity.

[2] Energy information based on 2 years of Wespine monthly energy data provided by Brad Barr
[3] Energy information based on 1 year of Laminex monthly energy data provided by Danny Griffin
[4] WAPRES data provided on the basis of energy modelling of new facility provided by WAPRES
[5] Estimate provided by Nick Harley from Hexion
[6] Estimate based on size of transformer at Preston chipping and conversations with operations manager

Figure 3: Relative locations

Scale/Location Options

Review of the energy data suggests that both Wespine and the proposed WAPRES pellet mill have a ratio of heat to electricity load that is well suited to cogeneration. In addition to this, their temperature requirements are relatively low which enhances the efficiency of the electrical generation component.

Laminex on the other hand has a ratio of heat to electricity that is very low and also requires high temperature heat. These factors suggest that biomass cogeneration will be less favourable.

To evaluate the potential for bioenergy cogeneration Enerbi has developed 5 potential scenarios as detailed in Table 2. In developing these scenarios Enerbi has utilised typical backpressure and condensing steam operating points that approximately align with the load points. In scenarios 1 and 4 the cogeneration system has been sized on the basis of the heat load, as this will lead to the most favourable economic outcome. The relatively close fit with electrical loads confirms that these two scenarios are well suited to cogeneration.

In scenarios 2, 3 and 5 the cogeneration system is sized on electrical demand with only the required heat produced.

The operating models are high level with assumptions based on experience, feedstock characteristics and vendor advice. With this in mind the estimated efficiencies and biomass requirements have an accuracy range of +/- 20%.

The locations have been selected on the basis of heat load as it is harder to transfer heat than electricity, i.e. new dedicated piping infrastructure vs existing or augmented electrical network. The exception to this is scenario 3, located at Laminex, because of the high temperature heat demand, this scenario would require the installation of a pipeline to Wespine to transfer heat.

Table 2: Scenario options for biomass cogeneration

Scenarios	Description	Location	Electrical output	Heat output	Feedstock (T/yr)[7]	Feedstock Energy (GJ/yr)
1	Wespine	Wespine	2.1 MW	11 MW	37,000 T	444,000
2	Laminex	Laminex	5 MW	5 MW	60,000 T	720,000
3	Wespine and Laminex	Laminex	7.1 MW	16 MW	97,000 T	1,164,000
4	Wespine and WAPRES	WAPRES	4.7 MW	21 MW	70,000 T	840,000
5	Everything	WAPRES	10MW	25 MW	130,000T	1,560,000

Feedstock Options

Having identified the potential scale of the bioenergy cogeneration system based on energy consumption, it is possible to sense check/refine these scenarios on the basis of available feedstock.

Enerbi undertook the feedstock assessment by discussing potential supply volumes, competing use cases and price points with a range of suppliers. The outcomes of this assessment are summarised in Table 3

[7] Based on model output for potential steam cycle operating conditions and pine residues @ 40-45% MC, ~12 GJ/T, accuracy range +/- 20% depending on feedstock detail and technology detail

Table 3: Summary of feedstock availability for Southwest Timber Hub

Type	Volume (T/yr)	Estimated Purchase Price ($/T)	Estimated Harvest/Delivery ($/t)	Total Price ($/T)	Distance (km)	MC	Energy Content (GJ/T)	Total Energy (GJ)	Specific Energy Cost ($/GJ)
Mixed wood waste	4,000	$5	$15	$20	20	40%	12	48,000	$1.67
Green waste	4,000	$5	$15	$20	20	45%	11	44,000	$1.82
Jarrah/Karri - timber house waste	10,000	$50	$10	$60	20	10%	17	170,000	$3.53
Pine harvest residues	60,000	$5	$45	$50	80	45%	12	720,000	$4.17
							Total	**982,000**	
								Average	**$3.83**

Mixed Wood Waste

Available from Bunbury /Harvey Regional Council and potentially Clean-Away tip site, this is essentially cleaned wood waste typically from construction or consumer delivery. The estimated volume was based on a visit to the BHRC on 20/10/20 and discussions with Kate Shaw from BHRC.

Green Waste

Available from Bunbury/Harvey Regional Council and potentially the Clean-away tip site. This is shredded and chipped green waste from tree lopping /yard clearing. The estimated volume was based on a visit to the BHRC on 20/10/20 and discussions with Kate Shaw from BHRC.

Jarrah/karri – Timber house Waste

Available from Peel Resources/West Coast Waste located adjacent to the BHRC site. This is cleaned, shredded, chipped and sized jarrah/karri demolition waste from house knockdowns. Previously this was supplied to Simcoa, however, this is no longer the case on the basis of suspected contamination, however, this was not confirmed. The estimated volume and details of the waste were provided by Scott Cross during a site visit on 20/10/20, Scott outlined that this volume could be increased if demand was present.

Pine Harvest Residues

The annual harvest from FPC owned pine forests and private forests results in significant quantities of residues – potentially up to 200,000 T/yr. Currently Laminex has first claim on these residues, however, does not utilise all of them due to the availability of sawdust from Wespine. The estimate provided in the table is based on conversations with FPC, Laminex and Wespine and represents the quantity of residue that is likely available and unsuitable for Laminex (bark, needles, small twigs, burnt etc…). This number requires further investigation in terms of quantum and the feasibility of achieving the price point for extraction and delivery.

In addition to the feedstock options in the table above there is also the potential to utilise hardwood residues from the native forests. If this was the case it would have a similar price point to the pine residues. The volume of this residue depends on the status of the WAPRES pellet mill as this is the proposed feedstock for this operation.

There may also be opportunities to utilise the chip fines from local chip mills but limited data was available for this and from all available reports this is already utilised as a garden product.

The initial assessment summarised in Table 3 suggests that Scenarios 3 and 5 may put strain on the potential residues/waste biomass resource availability in the area. Although these will still be considered in the fiscal analysis, they require further investigations into feedstock availability to ensure the quantity and price point can be maintained.

Technology Options

The preceding work has identified five potential scenarios for biomass cogeneration with three of these being more feasible based on the current understanding of biomass resource availability. To evaluate the viability of these scenarios capital and operating budgets are required.

The following section provides a brief introduction to commercial technology options that have been used to develop these capital and operating budgets.

Steam

The technology for steam-based biomass cogeneration is well established, having been refined over the last 100 years and now at a state of technical maturity. Traditionally biomass has been combusted and converted into steam which is then used to drive a steam turbine to generate electricity (Figure 4).

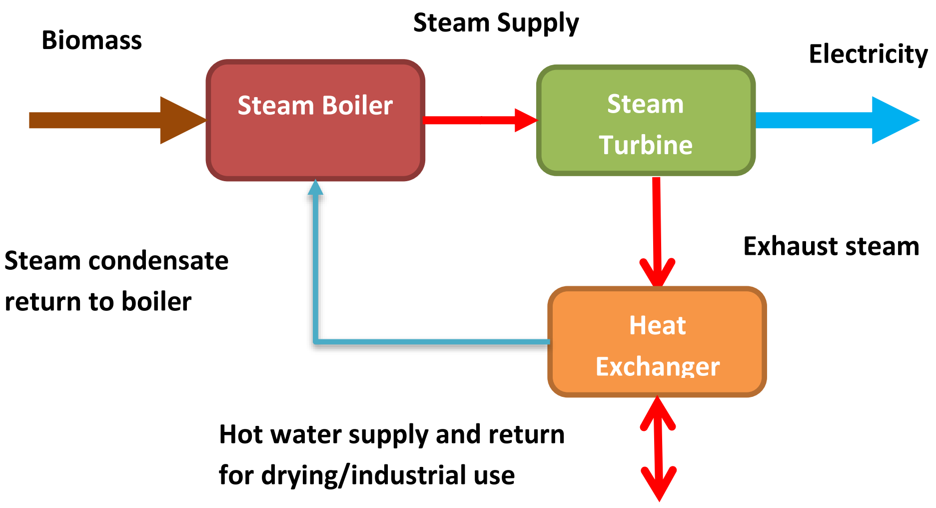


Figure 4: Basic flow diagram for Steam based Rankine cycle

In cogeneration applications the exhaust steam from the turbine is used to fulfill the heat demand (see Heat exchanger in Figure 4).

The major point of difference between different vendors is the type of combustion system that provides heat to the boiler. At the scales relevant to the Moore Rd Timber Precinct the two typical offerings are reciprocating stepped grate or fluidised bed.

Reciprocating Stepped Grate

The reciprocating stepped grate is the most common furnace/boiler architecture at the scale of interest, with the biomass progressively moved down the grate (typically cooled) allowing complete burn-out (see Figure 5). The hot combustion gases from the grate pass over the steam tubes (boiler) to generate the steam.

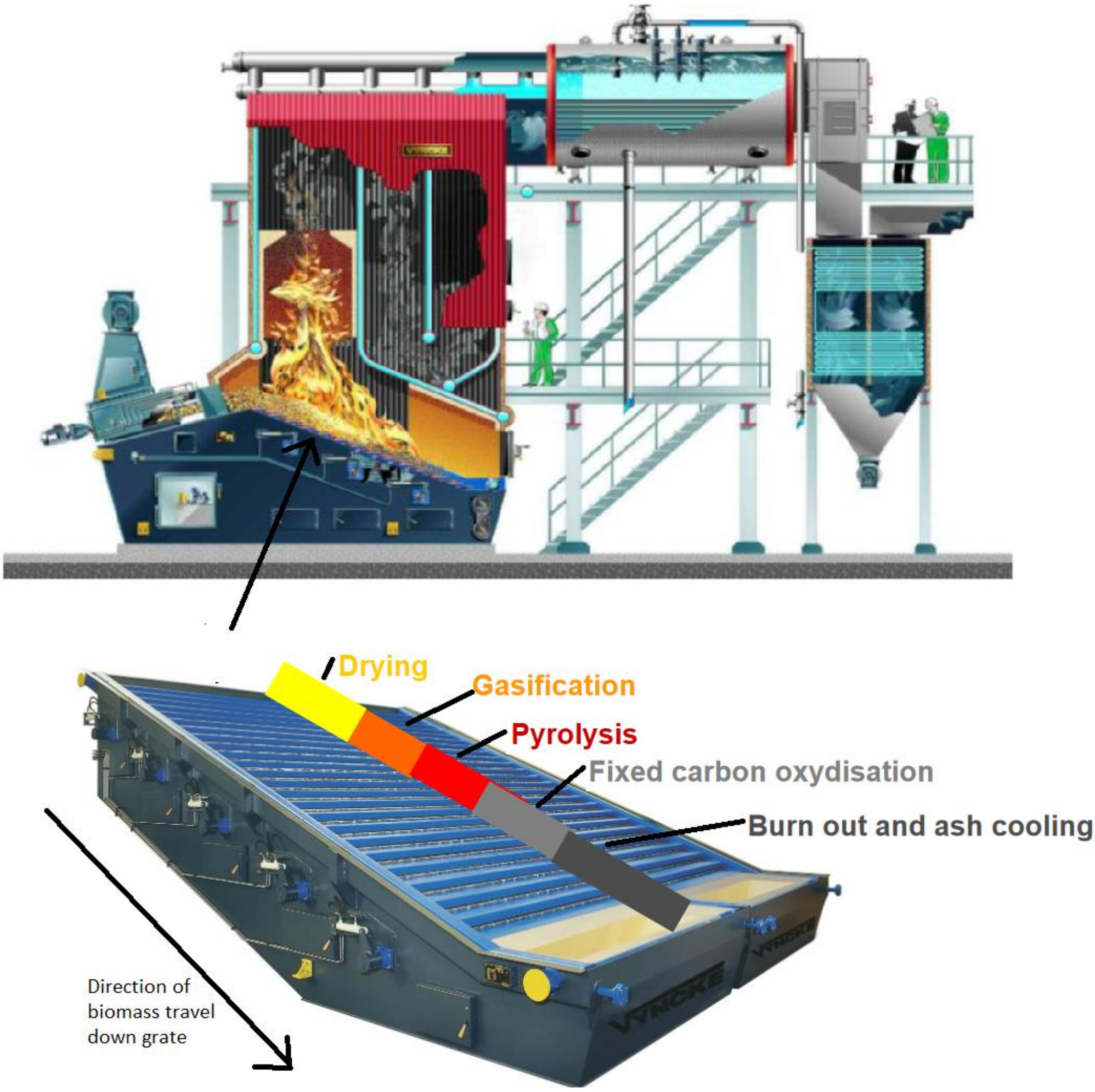


Figure 5: Overall schematic of boiler and detail shown of moving stepped grate (courtesy of Vyncke[8])

Due to continuing advances in this technology, it is possible to achieve very good emission outcomes and high thermal efficiencies while burning a range of fuels.

[8] http://www.novator.se/bioint/BPUA12Pres/2_BPUA12_Vincent_Weyne_VYNCKE.pdf

Fluidised Bed Combustion Systems

As the scale of the combustion systems increase (i.e. >10 MW_e) it is typical that bubbling and circulating fluidised bed combustion units are utilised. These systems use combustion air to fluidise a mix of sand and biomass to achieve high combustion efficiency. Figure 6 depicts a bubbling fluidised bed from the Scandavian company Valmet. Like moving grate systems these technologies are established with numerous references globally.

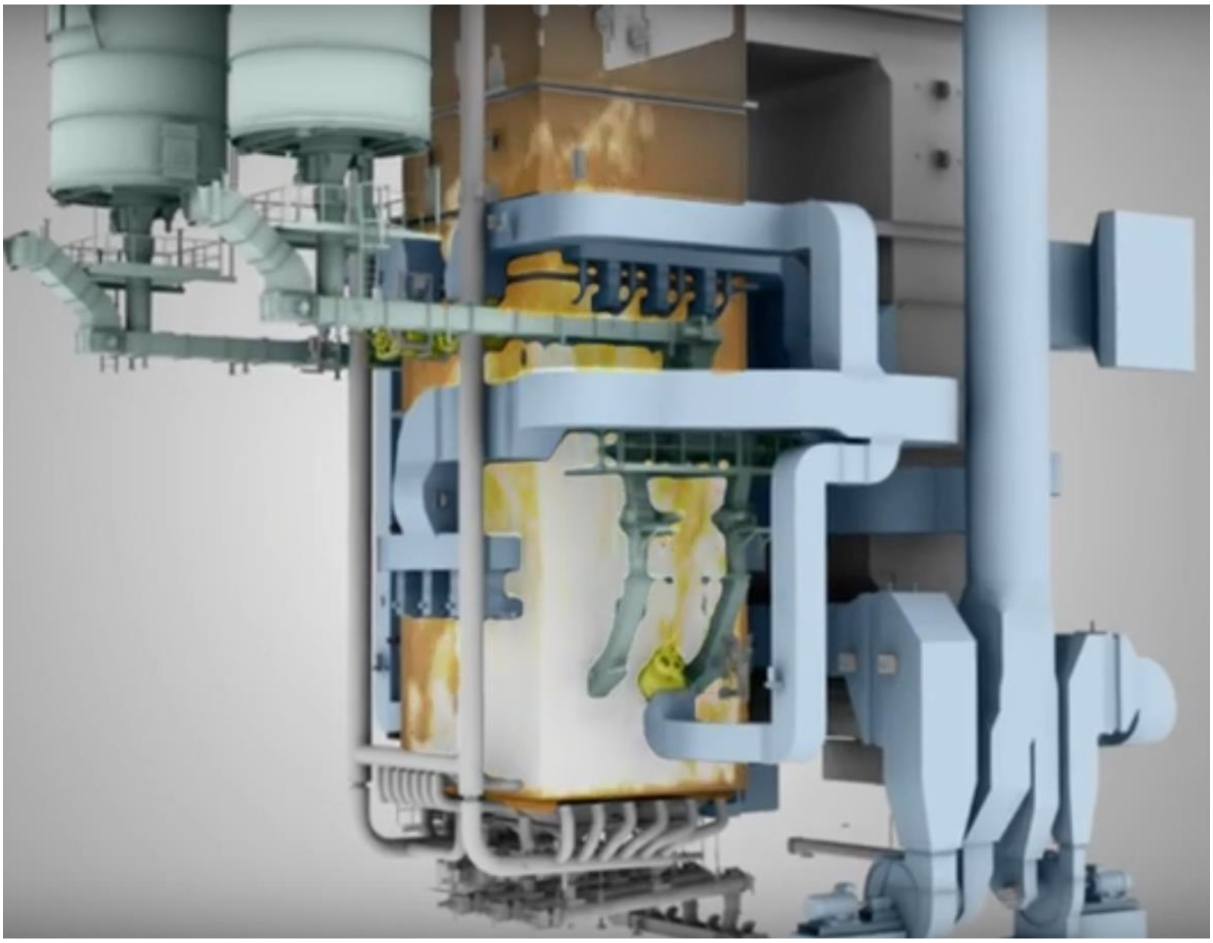
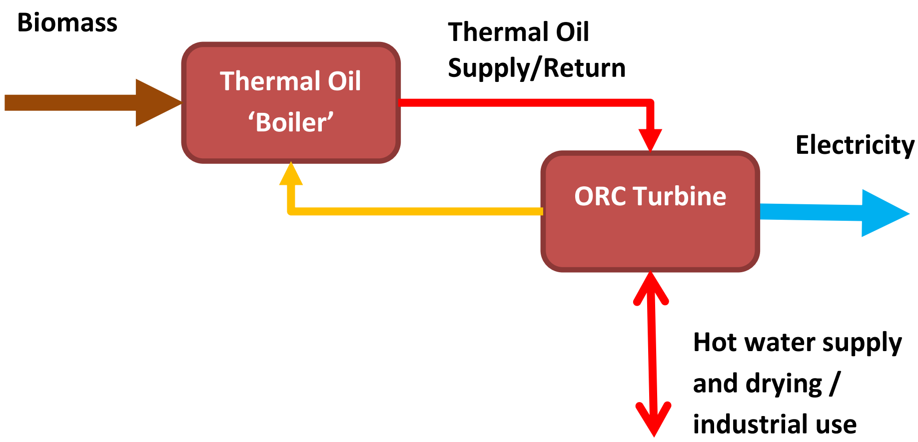


Figure 6: Valmet Bubbling Fluidised Bed boiler

ORC

Organic Rankine Cycles use the same thermodynamic principles as the steam system, however, instead of using water/steam as the working fluid through the turbine they utilise an organic fluid.

In these systems the biomass furnace (typically stepped grate) is used to heat thermal oil to approximately 330°C. This thermal oil is used to evaporate the organic working fluid in the turbine and drive the ORC turbine. The use of ORC's in the sub 3MW_e category has grown steadily since the 1990's as they offer very low running costs and comparable if not better efficiency then small steam systems despite higher capital cost.



The suppliers for thermal oil boilers are typically the same as those of steam boilers, however, there are only a few manufacturers of ORC turbines at the scale of interest. Below is an example of an ORC turbine system (including ancillaries) from Turboden in Italy.

Figure 7: 5.5MW$_e$ biomass fired Turboden ORC in Turkey

The operating simplicity and reduced maintenance cost of ORC systems is counteracted by their greater capital cost. Typically, ORC based systems having a capital cost that is 20-30% greater than an equivalent steam system. This trade-off plays out in different ways for different projects; however, steam systems currently have market share above 2MW.

Financial Model

The financial models for the different scenarios have been developed to provide a high-level review of biomass cogeneration viability in the Southwest Timber hub. Due to the number of assumptions involved in preparing capital/operating budgets the analysis outcomes are +/-30% confidence level.

Despite this lack of granularity, the outcomes of the results provide indication as to the most feasible scenario and if this should be further pursued.

Capital Budgets

The capital budgets have been based on the following core technologies:

- Water cooled Reciprocating stepped grate boiler operating at 480°C and 40 bar;
- Emissions control including multicyclone and bag house;
- Cogeneration through a combination of extraction and exhaust steam depending on the scenario

The operating points and sizing calculations used to estimate capital costs are based on feedback from vendors and similar plants.

It is also assumed the land used is available under a long-term low-cost rental arrangement, requires limited site works (i.e. clearing and levelling) and electricity is sold into the network with infrastructure upgrade costs in the range of $1-2 million.

Table 4: Capital budgets for scenarios

Scenarios	Description	Location	Electrical output	Heat output	Biomass Cogeneration Capital	Ancillary capital	Total Capital
1	Wespine	Wespine	2.1 MW	11 MW	$14,000,000	$1,000,000	$15,000,000
2	Laminex	Laminex	5 MW	5 MW	$24,000,000	$500,000	$24,500,000
3	Wespine and Laminex	Laminex	7.1 MW	16 MW	$35,000,000	$4,200,000	$39,200,000
4	Wespine and WAPRES	WAPRES	4.7 MW	21 MW	$27,000,000	$1,600,000	$28,600,000
5	Everything	WAPRES	10MW	25 MW	$45,000,000	$4,800,000	$49,800,000

For reference a 2.5 MW_e steam-based cogeneration plant using almond hulls as feedstock was installed in 2014 at Select Harvest in Victoria. This plant had a published capital cost of $12 million[9], however, discussions with the supplier (Vyncke) indicated it was closer to $14 million when all said and done.

The ancillary capital costs allow for the costs to utilise the heat energy at the prospective businesses and are made up of the following high level estimates:

- Cost to modify the Wespine drying kiln from direct fire to steam heat exchanger **- $1,000,000**
- Cost to augment existing thermal oil systems with heat exchangers at Laminex - **$500,000**
- Cost to install insulated pipeline from Laminex to Wespine capable of 10MW transfer - **$2,700,000 (1800m @ $1500/m)**

[9] http://member.afraccess.com/media?id=CMN://3A415377&filename=20141121/SHV_01576608.pdf

- Cost to install insulated pipeline from Wespine to WAPRES capable of 10MW transfer – **$600,000 (400m @ $1500/m)**

To simplify the analysis, it has been assumed that this ancillary cost is built into the overall capital project, however, it could also be managed via a reduced heat energy tariff and the individual companies covering upgrade costs.

Operating Budget Assumptions

In preparing the operating budgets the assumptions summarised in Table 5 have been applied.

Table 5: Assumptions for Operating budget

Inputs	Value	Unit
Biomass Energy content	12	GJ/T
Biomass price	$50	$/T
Operational hours	8000	hr/yr
FTE	$120,000	$/yr
Maintenance	$0.02	$/kWh
Power sales	$0.11	$/kWh
LGC	0.03	$/kWh
Heat sales	$6.00	$/GJ
Interest	3%	

Biomass Energy and price

The biomass energy content and price are based on an average value from Table 3.

Operational hours

The operational house allows for 4.5 weeks/yr of planned and unplanned maintenance.

FTE

The FTE cost is based on a fulltime wage of $100,000 plus 20% on costs. The FTE loading is 4 staff in scenarios 1/2/4 and 7 staff in scenarios 3 and 5.

Maintenance

An industry standard number of 2c/kWh has been applied, which allows for outsourcing maintenance labour outside of routine maintenance (e.g.: cleaning/greasing etc…).

Power and Heat Sales

The sale price for heat and power is an estimate based on representative average cost ranges for large scale users in the southwest timber hub.

Based on indicative information these rates have been estimated below:

- **Average annual cost of power:** $0.14/kWh
- **Average annual cost of natural gas energy:** $7/GJ

To be able to sell the electricity to individual users in the hub that are not on the same land title it will be necessary to register as a retailer with the IMO[10] and pay network fees. This requires further investigation and likely the development of a relationship with an existing retailer and Western Power. At this stage it has been assumed that this will cost either the cogeneration plant or the end user $0.03/ kWh. This leads to a sale price at the 'gate' of $0.11/kWh.

The heat energy sale price has been assumed to be $6/GJ.

LGC Income

The LGC (Large Generation Certificate) is a payment from the federal government for every MWh of renewable electricity produced. This price ranges from $30-40 depending on current demand and policy. In the analysis it has been assumed to be $30/MWh ($0.03/kWh).

Model Results

The preceding capital estimate and operating budget assumptions have been used to develop financial models of the different scenarios which are summarised in Table 6 on the following page. These models can be compared using the IRR and simple payback metrics provided in the table.

Scenario 4 represents the most financially viable option due to the full utilisation of heat and electricity loads as suggested by the heat to electricity ratio. The full-scale plant (scenario 5) is the second most viable option due to increasing economies of scale, however, this is a large-scale investment with potential feedstock risks. The least viable option is that located only at Laminex, this is the result of poor utilisation of heat and thus limited cogeneration.

These models do not take into account flow-on effects for end users including carbon credits that could be claimed due to energy displacement. It has been assumed this will form part of the negotiation when it comes to long term energy price contracts.

[10] Independent Market Operator

Table 6: Financial Model Summary

	Scenario 1 - 2.1MW	Scenario 2 - 5MW	Scenario 3 - 7.5MW	Scenario 4 - 4.7MW	Scenario 5 - 10MW
Gross Electrical Power (kWe)	2,300	5,300	7,500	5,000	10,500
Self Consumption (kWe)	200	300	400	300	500
Net Output (kWe)	2,100	5,000	7,100	4,700	10,000
Overall electrical efficiency (%)	13.6%	20.0%	17.5%	16.0%	18.0%
Thermal input (kW)	15,441	25,000	40,571	29,375	55,556
Heat output (MW)	11	4	15	21	24
Operating Metric					
Biomass consumption (T/yr)	37,059	60,000	97,371	70,500	133,333
Staff	4	4	7	4	7
Power generation (kWh/yr)	16,800,000	40,000,000	56,800,000	37,600,000	80,000,000
Heat generation (GJ/yr)	316,800	100,800	417,600	604,800	691,200
Operating Revenue					
Power sales ($/yr)	$1,848,000	$4,400,000	$6,248,000	$4,136,000	$8,800,000
REC income ($/yr)	$504,000	$1,200,000	$1,704,000	$1,128,000	$2,400,000
Heat income ($/yr)	$1,900,800	$604,800	$2,505,600	$3,628,800	$4,147,200
Total Revenue ($/yr)	**$4,252,800**	**$6,204,800**	**$10,457,600**	**$8,892,800**	**$15,347,200**
Operating Expense					
Labour ($/yr)	$480,000	$480,000	$840,000	$480,000	$840,000
Biomass ($/yr)	$1,852,941	$3,000,000	$4,868,571	$3,525,000	$6,666,667
Maintenance ($/yr)	$336,000	$800,000	$1,136,000	$752,000	$1,600,000
Total Expenses ($/yr)	**$2,668,941**	**$4,280,000**	**$6,844,571**	**$4,757,000**	**$9,106,667**
Operating Margin ($/yr)	**$1,583,859**	**$1,924,800**	**$3,613,029**	**$4,135,800**	**$6,240,533**
IRR (%)	**8.5%**	**4.8%**	**6.7%**	**13.3%**	**11.0%**
Interest costs ($/yr)	$450,000	$735,000	$1,176,000	$858,000	$1,494,000
Simple payback (years)	**13.2**	**20.6**	**16.1**	**8.7**	**10.5**

Other Factors

The initial outcomes of the biomass resource assessment indicate that bioenergy cogeneration can be viable in the Southwest Timber hub, however, this will require a scenario that ensures full heat utilisation (e.g.: scenario 1, scenario 4) or economies of scale (e.g: scenario 5).

This section considers business drivers, business structures, funding options, permit requirements and timing of the project.

Business Drivers

Globally the major drivers for biomass cogeneration are:

- Utilisation/disposal of low cost or problematic waste streams (e.g.: bagasse in sugar cane);
- High energy costs or limited infrastructure (no natural gas network);
- Security of energy supply; and
- More recently reduction of carbon footprint.

Energy costs and biomass availability

Historically in Australia, biomass cogeneration and biomass for heat projects have been successful in applications where large quantities of residual biomass are available at a point source and alternative heat supplies (e.g. LPG) have very high costs - $15-25/ GJ.

Long term residents of the Moore rd Timber precinct have previously investigated biomass cogeneration at various times over the last 20 years due to the availability of biomass and high heat consumption. The outcomes of these investigations have not led to the realisation of a cogeneration energy system due to financial non-viability and ease of using natural gas. The low cost of natural gas ~ $7/GJ vs the delivered cost of biomass energy $3.5-5/ GJ (no point source of low value biomass) leaves limited savings with which to justify the capital cost of the biomass system.

Security of supply and Carbon footprint

In 2008 the Varanus island gas explosion threatened supply of gas to the Moore rd users and provides an historical motivation to consider security of supply based around residues from the forestry process.

In a scenario where the majority of energy was provided by biomass cogeneration it would be possible for stakeholders to fix their energy costs for 10-20 years on the basis of a forestry resource that they have a vested interest in or indirectly control.

This translates to secure energy prices into the future that will not be subject to drastic increases that have been observed in the last 10 years.

The zero-carbon footprint of the biomass energy allows stakeholders to brand and sell products as low carbon into a market place where high carbon intensity is becoming a growing risk due to consumer sentiment and government policy.

Business Structures and Funding

The preceding analysis has been based on the bioenergy cogeneration operating as a separate entity that would:

- Rent land from an existing stakeholder;
- Operate and maintain the bioenergy cogeneration facility;
- Sell power and heat to stakeholders; and
- Purchase biomass from various sources (FPC, BHRC, private forestry and stakeholders if applicable).

This entity would necessarily have to raise the capital to build and operate this system. Due to the fact that the investment is in infrastructure, is supported by long term agreements with energy users and is green there are a range of options for raising finance including:

- **Clean Energy Finance Corporation (CEFC**) – The CEFC is a federal government body that is tasked with funding renewable and clean energy projects. In conversation the CEFC has indicated that this type and scale of project is within their investment priorities and they typically target 30% investment.
- **Superannuation funds –** This investment aligns with many current priorities of superannuation funds
- **Moore road stakeholders –** There is potential for the energy users to have a part ownership/equity share in the biomass cogeneration
- **Vendor finance/European Export bank –** Stimulus efforts and government support in European companies provides a number of opportunities for equipment suppliers to provide vendor/export finance.

In addition to these options there is also significant potential for grant funding from both state and federal bodies:

- **State:** Clean Energy Future fund
- **Federal:** ARENA – various programs

Permit Requirements and Timeline

A project of this scale will require the following permits prior to construction:

- **Planning approval** – Local shire for land use, noise, traffic changes etc…
- **Building approval** – Local shire for power station structures
- **Works Approval (Environmental) –** A works approval from the Department of Water and Environmental Regulation is required due to the air, water, solid, noise emissions that will be generated by the project
- **Electrical connection approval –** Western Power, approval will be required to connect to the network
- **Clean Energy Regulator –** Approval that LGC will be granted from chosen biomass resources

The above permits are likely to take 6-18 months depending on the work load of the relevant departments and the availability of information.

Lead time on equipment of this scale is 12-16 months delivered into Australia and construction and commissioning period ranges form 6-8 months.

It is possible that there could be overlap between the equipment lead time and permit application process but realistically the time frame for a project of this scale is between 2-3 years from final investment decision.

Way Forward

In light of the potential highlighted in this pre-feasibility assessment the next steps in pursuit of realising a biomass cogeneration project in the South West Timber hub are outlined below:

1. **Selection of Scenario(s) to focus effort on:**
    a. **Analysis suggests scenario 4, however, dependent on WAPRES pellet mill final investment decision**
2. **Identify likely business structure – suggest formation of an entity (company/special purpose vehicle/JV) and raise funding for feasibility study (stage 1) and detailed design (stage 2)**
3. **Appoint consultant to lead feasibility study and assist entity in negotiations with feedstock suppliers, investors and potential consumers**
4. **Stage 1**
    a. Entity to commence negotiations regarding long term feedstock contracts;
    b. Entity to commence discussions with investors based on preliminary budgets and timelines;
    c. Entity to draft sale contracts for power and heat/electricity sales with clients or retailer (depends on structure and stakeholders);
    d. Consultant to commence investigations with 3 leading global equipment suppliers to determine preferred supplier;
    e. Consultant to commence preliminary design work to assist with approvals and budgeting processes;
    f. Commence approval process with lead consultant to appoint specialist sub-consultants to prepare approval detail:
        1. Environmental consultant for works approval, including noise, emissions, transport plans etc…
        2. Electrical engineer for network approval
        3. Civil engineer for site works
        4. Structural engineer to review structures proposed by supplier
        5. Builder to design necessary buildings
        6. Town planner to assist with development application (if required)
    g. Consultant to present final budget and detailed timeline to allow for final investment decision by company and selection of preferred equipment supplier

If Final Investment Decision is approved:

5. **Stage 2**
    a. **Company to confirm equipment supplier**

b. **Consultant to commence detailed design process with supplier**
c. **Consultant to continue approval process**
d. **Project manager to be appointed**
e. **Consultant to transition to owners engineer role to assist project manager**
f. **Project manager to finalise contract with equipment supplier**
g. **Project implementation phase commences**

If scenario 4 was selected it is estimated that Stage 1 would take 6-8 months depending on progress made in finalising delivery structure.

For reference It is typical for project engineering to cost between 5-15% of the capital in the project and it would be expected that stage 1 and Stage 2 would represent a significant portion of these engineering costs.