Methodology and Assumptions

1.1 Defining the carbon capture process modeled

This study modeled a post-combustion amine-based carbon capture plant designed to capture CO_2 emissions from both an existing facility and an integrated biomass-fired combined heat and power (CHP) plant. Our model assumed that the CHP plant was a dedicated energy source, providing both the thermal and electrical power required for solvent regeneration and capture plant operations. The impacts of four biomass feedstocks on carbon capture plant design and capital and operating costs were evaluated.

The study involved process simulations and detailed design using Aspen Hysys and the Thermoflow software. Capital Expenditure (CapEx), Operating Expenditure (OpEx) and Levelized Cost of Capture (LCOC) of different cases were compared based on Association for the Advancement of Cost Engineering (AACE) Class 5 estimates.

1.2 Determining the operating conditions of the capture plant

This model assumed a capture plant availability of 85% (7,446 hours per year). A 10% steam margin was assumed to support capturing and compressing 95% of CO_2 emissions from both the existing facility and the CHP plant. Electricity was generated using a condensing turbine powered by steam from the biomass boiler.

1.2.1 Existing facility

CO_2 flow rates of 400,000, 600,000, and 800,000 tonnes per year emitted from the existing facility were evaluated in this study. The flue gas composition from the existing facility is outlined below.

Table 1. Flue Gas Composition from Existing Facility

Parameter	Unit	Value
Flue Gas Pressure	bar	0.948
Flue Gas Temperature	˚C	60
CO_2	%	13.0
H_2O	%	15.0
O_2	%	4.0
SO_2	ppm	5.0
N_2 and Others	%	68.0

1.2.2 CHP plant

Four types of biomass feedstocks were studied to compare the impact of biomass type on the cost and design of the carbon capture plant. The compositions of the biomass types included in this study are outlined below. The biomass price provided does not include the cost of transporting the biomass to the CHP plant, as this can vary significantly depending on the biomass location and CHP plant location.

Table 2. Biomass Compositions and Heating Values

Parameter	Unit	Biomass 1	Biomass 2	Biomass 3	Biomass 4
Higher Heating Values (at 25 ˚C)	kJ/kg	18,197	16,999	14,948	9,475
Lower Heating Values (at 25 ˚C)	kJ/kg	16,784	15,597	13,352	7,613
Moisture	%, weight	8.70	10.30	25.00	50.00
Ash	%, weight	0.50	4.20	0.41	2.34
Carbon	%, weight	45.80	42.45	37.62	23.66
Hydrogen	%, weight	5.50	5.27	4.52	2.94
Nitrogen	%, weight	0.08	0.52	0.07	0.29
Chlorine	%, weight	0.01	0.15	0.01	0.08
Sulfur	%, weight	0.01	0.06	0.01	0.03
Oxygen	%, weight	39.40	37.05	32.37	20.65
Biomass Price	CAD/GJ	6.44	3.96	8.09	8.11

1.3 Determining the CapEx and OpEx for the capture plant

Thermodynamic simulations of the biomass-fired CHP plant were performed using Thermoflow, while the process simulation of the capture plant was conducted using Aspen Hysys. The CapEx of different cases was compared based on AACE Class 5 estimates. This included direct field costs, indirect field costs, and non-field costs (taxes, permits, other project costs, escalation), in addition to contingency.

Both fixed and variable OpEx were evaluated in this project. The fixed OpEx in the analysis considered the costs of:

(i) Labour and support
(ii) Property taxes, insurance and contingency
(iii) Operations and operating consumables
(iv) Maintenance costs

The variable OpEx considered all utility and chemical consumptions, such as amine, chemical solvents, etc.

1.4 Determining by-product revenue

This study showed that by-products generated from the biomass-fired CHP plant, mainly excess electricity and fly ash, can also provide meaningful revenue streams. It's important to highlight that these revenue streams can vary based on regional market conditions, including local supply, demand and regulatory factors. To quantify these revenues in our model, we assumed a value of **CAD $0.103/kWh** for excess electricity sold to the grid and **CAD $103/MT** for fly ash sales .

To validate these assumptions, we benchmarked against publicly available data sources:

- **Electricity Pricing:** Electricity prices were referenced from GlobalPetrolPrices, which provides country-level electricity price data in USD/kWh. Using an exchange rate of 1.37 CAD/USD and applying a 95% confidence threshold, electricity prices across surveyed countries ranges from CAD $0.035/kWh to CAD $0.510/kWh, placing our assumed value of CAD $0.103/kWh well within this range.
- **Fly Ash Pricing:** Due to limited market data for biomass-derived fly ash, the market value for coal fly ash from imarc group was referenced, assuming similar value potential when quality standards are met. Using an exchange rate of 1.37 CAD/USD, fly ash prices for North America range from CAD$71.2/MT CAD $168.5/MT, placing our price assumptions of CAD $103/MT well within this range.

These revenue streams were included in the financial modeling to show how by-products help offset capital and operating costs, making the overall system more viable.

1.5 Determining the LCOC

To properly assess the economic viability of a carbon capture project, it is important to determine the LCOC. This model assumed the construction period of the biomass-fired CHP, capture plant, and balance of plant to be three years. The cost distribution is considered as 10%, 60%, and 30% for the total overnight capital from January 2027 through December 2029. The first year of operation in 2030 was considered with the expected operating costs for 25 years. Table 5 shows the assumptions used for the LCOC calculation.

Table 3. Assumptions used for LCOC calculation

Parameter	Assumption
CapEx Period	3 years
Start CapEx Year	2027
Operational Period	25 years
Distribution of TOC	
- 1st Year	10%
- 2nd Year	60%
- 3rd Year	30%
First Year of Operation	2030
Escalation of CapEx	3%
Escalation of Fixed OpEx	3%

Escalation of Variable OpEx	3%
Escalation of By-product Revenue	3%
Discount Rate	8%