Methodology and Assumptions

Defining the carbon capture process modeled

This study modeled two carbon capture technologies to capture the CO_2 from the flue gas of a hypothetical natural-gas fired cement plant. To compare CO_2 captured and avoided, utility usage, and the sensitivity of carbon capture economics to key input variables, two scenarios were analyzed.

1. **Amine-Based Carbon Capture with addition of an Auxiliary Boiler:** The post-combustion capture plant was designed to capture CO_2 emissions from both the existing cement plant and the integrated auxiliary boiler.
2. **Cryogenic Carbon Capture:** The post-combustion capture plant used cryogenic distillation to capture CO_2 emissions from the existing cement plant.

The study involved process simulations and detailed design to evaluate both technologies. Aspen HYSYS was used to model the cryogenic carbon capture system, while the amine-based carbon capture system was modeled using Aspen HYSYS and Thermoflow. CO_2 transportation and storage fall outside the scope of this project and were therefore excluded from the analysis.

Determining the operating conditions of the capture plant

Both the amine-based and cryogenic carbon capture models assumed a 90% carbon capture efficiency and a plant availability of 85% (7,446 hours per year).

Existing cement plant

CO_2 emissions from the hypothetical natural-gas fired cement plant were estimated at 1.1 million tonnes per year. This flow rate was selected for the design basis to meet a target of 1 million tonnes of CO_2 captured annually, assuming a 90% capture efficiency. The detailed flue gas composition from the cement plant is outlined below.

Table 1: Flue Gas Composition from Existing Cement Plant

Parameter	Unit	Value
Flue Gas Pressure	bar	0.94
Flue Gas Temperature	˚C	120
CO_2	%	12.36
H_2O	%	17.00
O_2	%	10.38
N_2 and Others	%	60.26

Amine-based carbon capture plant

The HYSYS model included key process equipment for CO_2 capture, solvent regeneration, dehydration, compression, and associated water treatment and cooling systems. It was assumed that the capture plant used an amine blend of monoethanolamine (MEA) and methyl diethanolamine (MDEA).

An auxiliary boiler, fueled by natural gas, was added to supply the steam required for amine regeneration and dehydration system regeneration. A 10% thermal energy margin (in the form of steam) was factored into the design. The thermal energy produced by the auxiliary boiler supports 90% CO_2 capture from both the cement plant's flue gas and the auxiliary boiler's flue gas. An electric CO_2 compressor was utilized in this case.

Cryogenic carbon capture plant

The HYSYS model for the cryogenic capture system included key process equipment for CO_2 separation using distillation, dehydration, and compression, along with associated cooling and water treatment systems. Unlike amine-based systems, cryogenic distillation capture technology does not require steam or chemical solvents for CO_2 capture. Instead, the process relies primarily on electricity to power refrigeration cycles, compression stages, and its balance of plant (BOP). It is assumed that the host site was able to procure the power necessary for the cryogenic process.

Determining the CapEx and OpEx for the capture plant

The CapEx for the amine-based carbon capture plant was estimated using Aspen Capital Cost Estimator (ACCE) based on the Association for the Advancement of Cost Engineering (AACE) Class 5 estimates. The CapEx for the cryogenic carbon capture plant was estimated using a cost ratio ($CapEx_{cryo}$/ $CapEx_{amine}$) derived from Aspen HYSYS. For this high-level study, this ratio was applied to the AACE Class 5 capital cost estimate for the amine-based plant to determine the cryogenic plant's CapEx. The CapEx included direct field costs, indirect field costs, and non-field costs (taxes, permits, other project costs, escalation), in addition to contingency.

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

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

The variable OpEx for the amine-based capture plant considered all utility and chemical consumptions, such as amine, chemical solvents, fuel, and electrical power. In contrast, the variable OpEx for the cryogenic capture plant was primarily comprised of electrical power consumption.

Determining the Levelized Cost of CO_2 Avoided (LCOA)

To assess the economic viability of a carbon capture project, it is important to determine the LCOA. This model assumed the construction period of the auxiliary boiler, carbon capture plant, and BOP to be three years. Its cost distribution is considered as 10%, 60%, and 30% for the total overnight capital (TOC) from January 2027 through December 2029. The first year of operation was assumed to be 2030, with operating costs projected over 25 years of capture plant operation. Table 2 shows the assumptions used for the LCOA calculation.

Table 2: Assumptions used for LCOA 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%

Economic Sensitivity Inputs

Project Costs

The capital costs in the model included the nominal value, a low scenario at 70% of the nominal value, and a high scenario at 150% of the nominal value. Both scenarios were assumed to be greenfield projects, with no additional tie-in costs beyond those captured by the software. In both cases, the CO_2 was compressed for transportation using an electrically driven compressor.

Utility Pricing

Nominal power prices were estimated based on historical data, and the Alberta Electrical System Operator's supply and demand forecasts. The nominal power price was assumed to be $75.00/MWh starting in 2025. The low power price was assumed to be 80% of the nominal price. Both low and nominal pricing had 3% annual escalation applied after 2025. The high power price assumed Alberta's rate at $120.60/MWh for 2025 and 2026, with a 3% annual escalation applied starting in 2027.

Carbon Pricing

There is significant uncertainty around carbon pricing in Alberta. Carbon prices were developed based on federal and provincial carbon taxes (i.e., Technology Innovation and Emissions Reduction, or TIER, in Alberta) in mid-2025. The nominal carbon tax was assumed to be $95/tonne, held constant from 2025 onwards. The high carbon tax price was assumed to gradually increase from $95/tonne in 2025 to $170/tonne in 2030, aligned with the current federal backstop schedule and price. After 2030, 3% annual escalation was applied. The low carbon tax price was assumed at $0/tonne, modelling a scenario where Alberta does not have large emitter carbon pricing.

The carbon tax threshold assumed an emission reduction target factor of 0.28, held flat from 2030 onwards. This means the facility reduced its emissions by 28% from its baseline levels by 2030 (when CCUS operation begins) and maintained this level of reduction for the lift of the project to avoid paying carbon taxes. CO_2 emissions reduced below the emission reduction target factor were considered eligible to generate carbon credits. The value of these carbon credits was assumed to be 50% of the carbon tax value.

Government Incentives

It was assumed that 100% of the captured CO_2 will be geologically stored. Both scenarios assumed that the capture facility starts up on January 1, 2030 and 50% of eligible capital was returned to the project owner. Ineligible capital included early engineering, taxes and permitting, contingency, and other indirect costs from ACCE. The CCUS ITC calculation included accelerated depreciation, and it was assumed that the project owner had other revenue to claim depreciation against.

Under the Alberta Carbon Capture Incentive Program (ACCIP), up to 12% of eligible project costs are returned to the project owner over a three-year period following startup. For modelling purposes, the same amount of eligible capital was assumed for both the ACCIP and CCUS ITC.

Summary of Model Inputs:

The project parameters used in the economic sensitivity analysis are summarized in Table 3:

Table 3: Project Parameters

Parameter	Low Value	Nominal Value	High Value
Carbon Tax Price	$0/t	$95/t	$170/t[1]
Carbon Credit Price	$0/t	$47.50/t	$85/t[1]
Capital Costs[2]	-30%	Nominal	+50%
Operating Costs[2]	-30%	Nominal	+50%
CCUS ITC	OFF	ON, 50% of eligible capital	
ACCIP	OFF	ON, 12% of eligible capital	
Natural Gas Price[2]	$0.94/GJ	$2.71/GJ	$4.47/GJ
Power Price[2]	$60/MWh	$74/MWh	$120/MWh

[1] 3% annual inflation applies after 2030

[2] 3% annual inflation applies after 2025

In addition to the parameters above, the economic model inputs listed in Table 2 were used to calculate the project's NPV.