Methodology and Assumptions

Carbon Capture Models

Aspen HYSYS was used to simulate a post-combustion amine-based carbon capture plant designed to capture CO_2 emissions from a natural gas-fired power plant located in Alberta, which emits 230,000 tonnes per annum (tpa) of CO_2. The HYSYS model includes 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 uses an amine blend of monoethanolamine (MEA) and methyl diethanolamine (MDEA), with a target capture efficiency of 95%. CO_2 transportation and storage fall outside the scope of this project and were therefore excluded from the analysis.

Two case studies were examined to understand which economic inputs have the largest influence on a carbon capture project's Net Present Value (NPV).

In the first scenario, an auxiliary boiler was added to supply the steam required for amine regeneration. The flue gas produced by this boiler was processed through the capture plant, along with the flue gas from the natural gas-fired power plant.

In the second scenario, a combined heat and power (CHP) plant was added to supply both steam and electricity required for amine regeneration and capture plant operations. The CHP plant was simulated in THERMOFLEX® v31.0 by Thermoflow. Steam extracted from the back pressure turbine within the CHP plant was used for amine regeneration, CO_2 dehydration system regeneration, and to drive a CO_2 compressor. Electricity from the CHP plant was used within the capture plant, with any excess sold to the grid. The flue gas produced by the CHP plant was processed through the capture plant, along with the flue gas from the natural gas-fired power plant. The addition of the CHP plant, along with the need to increase the size of the capture plant to treat additional CO_2 volumes, resulted in a capital cost that was higher than in the auxiliary boiler scenario.

CO_2 Captured vs. CO_2 Avoided

Carbon credit generation and carbon tax avoidance are based on CO_2 avoided volumes, not the total amount of CO_2 captured. CO_2 captured refers to the amount of CO_2 that is removed from the combination of flue gases by the capture system. CO_2 avoided represents the net reduction in emissions, accounting for the original emissions from the host facility minus the remaining emissions not captured.

In the auxiliary boiler scenario, the total CO_2 captured was 260,000 tpa, and the CO_2 avoided was 200,000 tpa. In the CHP plant scenario, the total CO_2 captured increased to 330,000 tpa due to the higher CO_2 emissions from the CHP plant. However, CO_2 avoided decreased to 195,000 tpa because the carbon capture facility could not remove all of the additional CO_2 it receives. The CHP scenario generated fewer carbon credits than the auxiliary boiler scenario because the CO_2 avoided was lower.

Project Costs

For both scenarios, capital cost estimates were developed using Aspen Capital Cost Estimator (ACCE), following the Association for the Advancement of Cost Engineering (AACE) Class 5 guidelines. The capital costs included 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 a steam-driven compressor.

Non-fuel operating costs were developed through Aspen. Operating costs included staffing and support, maintenance, chemicals and consumables, property taxes, and insurance. Natural gas and power consumption estimates were taken from the Aspen models.

Utility Pricing

Natural gas was modeled as the fuel used to produce heat for the capture plant. The Alberta Energy Regulator's AECO-C price forecasts from June 2025 were used as the low, nominal, and high cases for natural gas pricing. A 3% annual escalation was applied after 2034.

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. TIER allows CCUS projects to generate a variety of types of credits which may have different accounting rules and values for emitters. For the purposes of this evaluation, all types of credits were considered of equal value.

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 the CCUS operation begins) and maintained this level of reduction for the life of the project to avoid paying carbon taxes. CO_2 emissions reduced below the emission reduction target 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. To maximize tax credits from the CCUS Investment Tax Credit (ITC), both scenarios assumed that the capture facility started 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, home office costs, and other indirect costs from ACCE. The dual use factor for the CHP plant was 83%, meaning 83% of the energy from the CHP plant was used for capture and is eligible for the CCUS ITC. The CCUS ITC calculation included accelerated depreciation and it is 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.

Model Inputs:

The project parameters are summarized in Table 1:

Table 1: 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

All of the parameters were entered into a probabilistic economic model. A discount rate of 8% was used to calculate the project's NPV. The NPV is the sum of the project's cash flows, discounted at 8%. Other model inputs are listed in Table 2.

Table 2: Model Inputs

Parameter	Assumption
Capital Expenditure Period	3 years
Start Capital Expenditure Year	2027
Operational Period	25 years
Distribution of Capital	
- 1st Year	10%
- 2nd Year	60%
- 3rd Year	30%
First Year of Operation	2030
Escalation of Capital	3%
Escalation of Non-fuel Operating Costs	3%
Escalation of Utility Costs	3%
Discount Rate	8%