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Capture, Transport And Injection Of High CO2 Emitting Source In An Onshore Field Of India – An Integrated Modeling Case Study Towards Net- Zero

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Abstract

1. ***Objective/Scope:*** *This paper evaluates the feasibility of an integrated Carbon Capture and Storage (CCS) system for India's cement industry. The scope includes capturing CO_2 emissions from cement plants, transporting through optimized supercritical CO_2 pipelines, and injecting into a depleted reservoir in the Cambay Basin. The study aims to establish a practical framework for industrial-scale CCS implementation in hard-to-abate sectors.*

2. ***Methods/Procedures/Process:*** *A structured methodology is developed using emission data from three cement plants. Post- Combustion capture with amine-based solvents was selected for 90% efficiency. The captured CO_2 was compressed to a supercritical state and transported through a custom-designed API X65 carbon steel pipeline network, with booster stations at ~50 km intervals. Pipeline design considered velocity, pressure drop, and material safety. Appropriate injection methodology was designed and assessed through reservoir characterization, considering pressure drop estimates as well as the injectivity index estimation for the target reservoir in Cambay Basin.*

3. ***Results/Observations/Conclusions:*** *Results indicate that the three plants emit ~1.58* Mt *CO_2 annually, out of which ~1.42* Mt *CO_2 was captured. Pipeline modeling at 2 m/s velocity minimized pressure drops, with booster stations ensuring supercritical conditions throughout transport. API X65 steel provided a cost-effective and safe pipeline material. Subsurface injection into the Cambay Basin demonstrated feasible injectivity (15.96 m^3/day/MPa) and safe operations below the fracture pressure. However, individual well storage capacity (~33 kt) was limited, requiring a multi-well strategy for large-scale deployment. This work confirms the technical feasibility of CCS for Indian cement plants, while also highlighting scalability and economic challenges.*

4. ***Novelty/Contribution:*** *This study represents the first integrated CCS modeling framework for India's cement sector, combining capture, supercritical pipeline design, and validated reservoir injectivity. Unlike global CCS projects focused on power plants, it provides sector-specific solutions for cement, offering a replicable integrated model for CO_2, from capture to injection, for India's decarbonization strategy, further facilitating the country's commitment towards net zero and U.N. sustainable development goals.*

Keywords: *Carbon Sequestration, CO_2 capture, CO_2 Transportation, Pipeline Design, Optimization, Decarbonization.*

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1. INTRODUCTION

1.1. Importance of CCS in Mitigating Climate Change

Carbon Capture and Storage represent one of the most promising technological solutions for reducing greenhouse gas emissions while allowing continued use of existing energy infrastructure. CCS encompasses an integrated suite of technologies that can prevent large quantities of CO_2 from being released into the atmosphere from the use of fossil fuels. This proven technology has been in safe, commercial operation for approximately 45 years [1]. The Intergovernmental Panel on Climate Change (IPCC) has emphasized that if we are to achieve the ambitions of the Paris Agreement and limit future temperature increases to 1.5^0C, we must do more than just increase efforts to reduce emissions we also need to deploy technologies to remove CO_2 from the atmosphere [2]. CCS stands as one of these critical technologies, offering a pathway to significant emissions reduction.

Recent climate mitigation pathways clearly identify the large-scale deployment of CCS as essential for meeting global climate goals. Current plans indicate an eight-fold increase in CCS capacity by 2030, reflecting the growing recognition of its vital role [3]. However, the feasibility of CCS expansion remains a subject of debate among experts. Analyses of historical growth patterns for CCS and other policy-driven technologies suggest that if current plans double between 2023 and 2025 and their failure rates decrease by half, CCS could reach 0.37 $GtCO_2$ per year by 2050 [3]. While this projection falls below the requirements of most 1.5^0C pathways, it exceeds the benchmarks for many 2^0C scenarios, highlighting both the challenge and potential of CCS deployment.

The importance of CCS extends beyond its direct climate benefits. As nations increasingly commit to carbon neutrality targets, CCS provides a crucial bridge technology that allows for the continued operation of essential industrial processes while transitioning to more sustainable energy systems. The technology offers a means to address emotions from hard-to-abate sectors such as cement and steel production, where few other viable alternatives exist for significant emissions reduction [2].

1.2. Overview of Exiting Technology

CCS technology functions through three primary stages: capture, transport, and storage. Each component represents a distinct technological challenge with various established and emerging approaches. The capture phase involves separating CO_2 from other gases produced at large industrial facilities. Transport entails compressing the captured CO_2 and moving it via pipelines, ships, or other methods to suitable storage sites. The final storage phase consists of injecting the CO_2 deep into underground rock formations where it can be permanently sequestrated [1].

The capture component of CCS employs various methodologies depending on the industrial process and existing infrastructure. Post-combustion capture technology represents the most commercially mature approach, where CO_2 is separated from flue gases after fuel combustion. Pre-combustion capture involves converting fuel into a mixture of hydrogen and CO_2 before combustion, allowing for easier separation. Oxy-fuel combustion uses pure oxygen for combustion, resulting in flue gas composed primarily of CO_2 and water vapor, which simplifies separation [4].

Technological advancements continue to improve CCS viability across all components. The 2023 State of the Art CCS Technologies report [5] highlights ongoing developments in new and improved methods for capturing carbon dioxide, including several technologies utilizing calcium looping and metal organic frameworks (MOFs). For transport and storage, new technologies focus on robust design and monitoring to provide safe and optimized infrastructure [5]. These innovations aim to improve energy efficiency, reduce costs, and enhance overall system performance for future CCS projects.

All components of CCS employ proven technologies with decades of commercial-scale application. Since 1972, when several natural-gas processing plants in Texas began employing carbon capture for enhanced oil recovery operations, more than 200 million tons of CO_2 have been captured and injected deep underground [1]. This established track record provides confidence in the fundamental technical feasibility of large-scale CCS deployment.

1.3. CO_2 Emissions by Cement Industries

The cement industry represents one of the most significant sources of industrial carbon emissions globally. Current estimates indicate that global cement manufacturing is responsible for approximately 8% of the world's total CO_2 emissions [6]. If considered as an independent entity, the cement industry would rank as the world's third or fourth- largest emitter of carbon dioxide. In 2022 alone, global cement manufacturing produced 1.6 billion metric tons of CO_2 [6].

Unlike other industrial sectors where the largest share of emissions comes from energy use, in cement and concrete production, more than half are process emissions that occur during the chemical transformation of limestone to clinker [6]. This fundamental characteristic makes decarbonization particularly challenging, as even complete energy system transformation would not eliminate these process emissions. The industry therefore requires either novel solutions to a millennia-old sector or strong reliance on carbon capture technologies.

The situation becomes more pressing when considering future projections. Global annual concrete production is forecast to grow from 14 billion cubic meters today to 20 billion cubic meters by mid-century, driven by continued urbanization and growing infrastructure demands in developing economics [6]. Without significant intervention, this trajectory would result in CO_2 emissions from the sector increasing to approximately 3.8 billion tons per year based on current practices [6].

The cement industry is expected to grow between 12 and 23% from 2005 to 2050, with a disproportionate amount of this growth occurring in non-OECD countries [7]. The unique challenges facing cement industry decarbonization make it one of the most crucial application areas for CCS technology. Implementing carbon capture in cement production offers one of the few viable pathways to significantly reduce the sector's substantial carbon footprint, while meeting growing global demand for this essential building material.

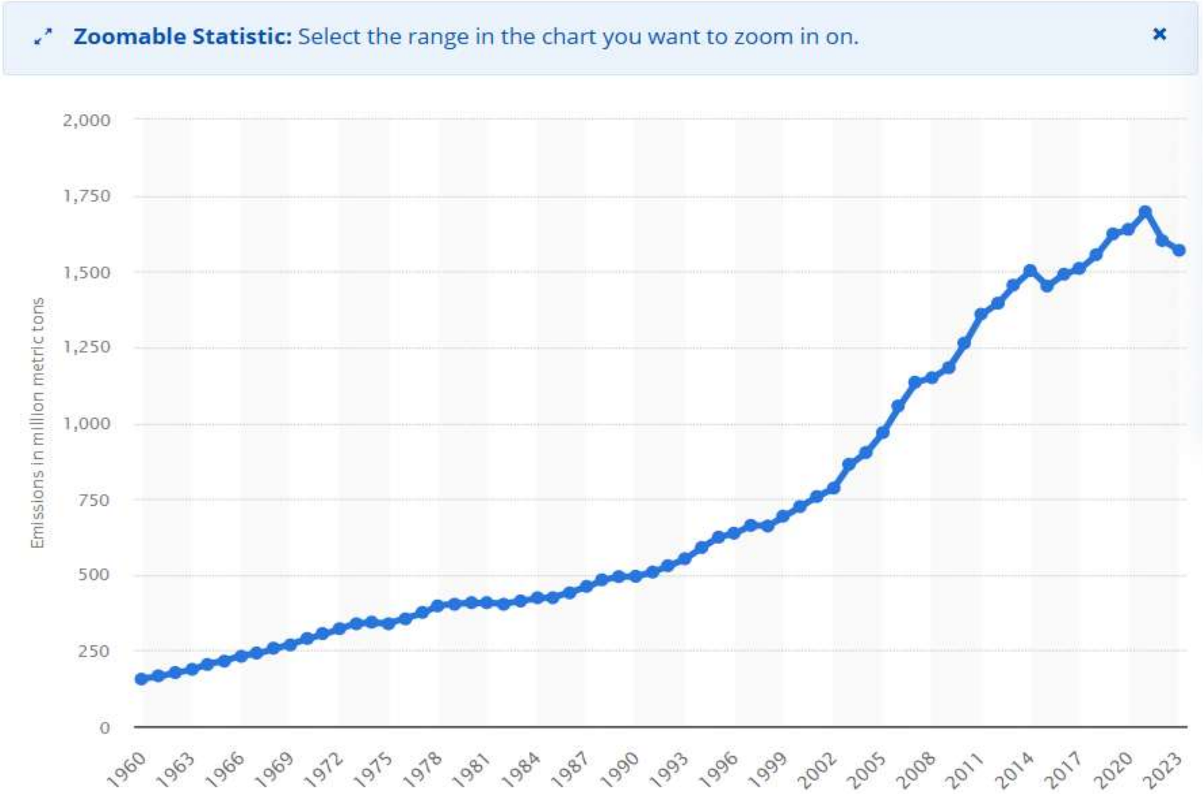

Figure 1: Carbon Dioxide Emissions from the Manufacture of Cement Worldwide from 1960 to 2022 (in Million metric tons) [6].

2. Background

2.1. CCS Overview in India

India's approach to Carbon Capture and Storage is evolving within the context of its unique energy and economic development needs. As the world's third largest emitter, India faces the dual challenge of sustaining economic growth while addressing climate concerns [8]. The narrative around CCS/CCUS technology has been regaining momentum in India as the country explores feasible pathways toward emissions reduction without compromising energy security and industrial development [9].

This ministry of Petroleum and Natural Gas, Government of India, in coordination with various stakeholders, has initiated efforts for development and implementation of Carbon Capture, Utilization and Storage techniques in the oil and gas sector. A task force titled "Upstream for CCS/CCUS" (UFCC) has been constituted to this effect [8]. Additionally, to develop and implement a practicable on carbon capture, utilization and storage in India, a Memorandum of Understanding has been signed between the Ministry of Petroleum and Natural Gas and IIT Bombay [8].

Despite these initiatives, CCS in India remains at a nascent stage compared to some other countries. The technology has not gained significant focus historically because of limited research, financial support, and policy frameworks specific to CCS [9]. However, this situation is gradually changing as both the government and industry recognize the potential role of CCS in India's low-carbon transition. The essential role of CCUS in India's low-carbon future revolves around three key areas: research and development, finance, and policy [9].

A notable development in India's CCS landscape is the planned project by Australia- headquartered Synergia Energy in Cambay, Gujarat. Synergia plans to develop what it describes as India's first end-to-end carbon capture and storage scheme, which could aid India's emission-reduction goal [10]. However, the project faces challenges including funding requirements, the need for a regulatory framework, and incentives for emitting companies to implement CCS technology. Synergia has started that it will assist the Directorate of Hydrocarbons in developing a regulatory framework, which may initially result in the amendment of the Cambay production- sharing contract to incorporate CCS activities [10].

2.2. CCS Potential in Cambay Basin

The Cambay Basin represents one of the most promising geological formations for Carbon Storage in India. Synergia Energy's proposed CCS project in this region aims to transport and store CO_2 from up to 16 major combined-cycle gas turbine plants and coal-fired power stations located in the proximate of the Cambay field. The company estimates that CO_2 emissions from these plants could peak at 43 million tons per year, though no specific timeline has been provided [10]. Synergia is targeting a substantial storage capacity of more than 500 million tons of CO_2 in the basin.

The geological characteristics of the Cambay Basin make it particularly suitable for CO_2 storage. The Eocene Cambay Shale formation has been well-studied for its hydrocarbon potential with investigations revealing total organic carbon ranging from 0.37-10.68 weight percent, with an average of 2.43 weight percent [11]. The vitrinite reflectance values range between 0.46%-0.7%, indicating an immature to early oil generation stage. While the study suggests that the high clay content (average 62.9%) and poor to moderate brittleness might restrict fracability for tight gas or tight oil exploration, these properties could potentially be advantageous for CO_2 storage by providing effective sealing mechanisms.

2.3. Supercritical CO_2

Supercritical CO_2 is a fluid state of carbon dioxide where it is held at or above its critical temperature (304.128 K; 30.978^{0}C) and critical pressure (7.3773 MPa; 73.773 bar) [6]. In this state, CO_2 exhibits properties midway between a gas and liquid as it expands to fill its container like a gas but with a density state similar to that of a liquid. This higher density state is crucial for CCS applications as it allows more efficient use of storage space in geological formations.

The physical properties of supercritical CO_2 make it particularly suitable for geological storage. Its relatively high density means larger quantities of CO_2 can be stored in a given volume compared to gaseous CO_2. Additionally, Supercritical CO_2 is becoming an important commercial and industrial solvent due to its role in chemical extraction, alongside its relatively low toxicity and environmental impact [12]. This property could potentially create additional utilization opportunities for captured CO_2 in the future.

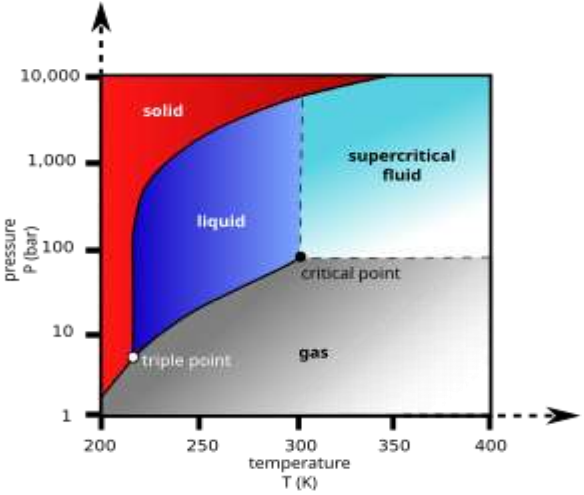

Figure 2: CO_2 Pressure-Temperature Phase Diagram [12].

2.4. CO_2 Capture Technologies

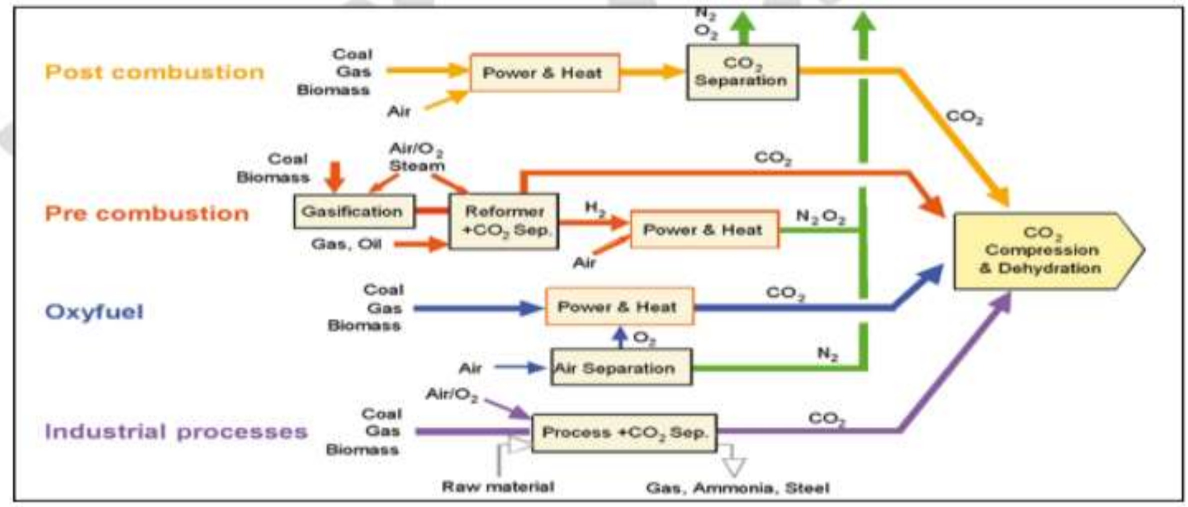

Figure 3: Carbon Capture Technologies [8].

Among the various carbon capture technologies available, post-combustion capture has emerged as the most widely implemented approach, particularly for existing facilities. In post-combustion capture, fuel is burned as normal in a more-or-less unmodified powerplant, and the CO_2 is subsequently separated from the flue gas [4]. This approach offers several significant advantages that have contributed to its prominence in current CCS deployments.

The primary advantage of post-combustion capture is its compatibility with existing infrastructure. This technology can be applied to already constructed plants as a retrofit, where components can be replaced, developed, and upgraded without fundamental impacts on the power plant itself [4]. This flexibility allows for staged introduction of carbon capture onto a plant, which reduces disruption to operations as well as investment risk. The retrofitting capability is particularly valuable, given the significant global fleet of existing power plants and industrial facilities that will continue to operate for decades.

Currently, the most commercially mature technology for post-combustion capture is chemical absorption. In this process, CO_2 is absorbed from the flue gas in a separation tower using a solvent and then regenerated by heating in a recovery column at temperatures over 100^0C [0]. While effective, this approach does face certain challenges, most notably the large energy penalty associated with thermal solvent regeneration. Other issues include large equipment requirements due to high volumes of flue gas, corrosion of equipment in the presence of oxygen and other impurities, solvent degradation, potential releases of harmful solvent degradation products, and disposal requirements for expired solvent [4].

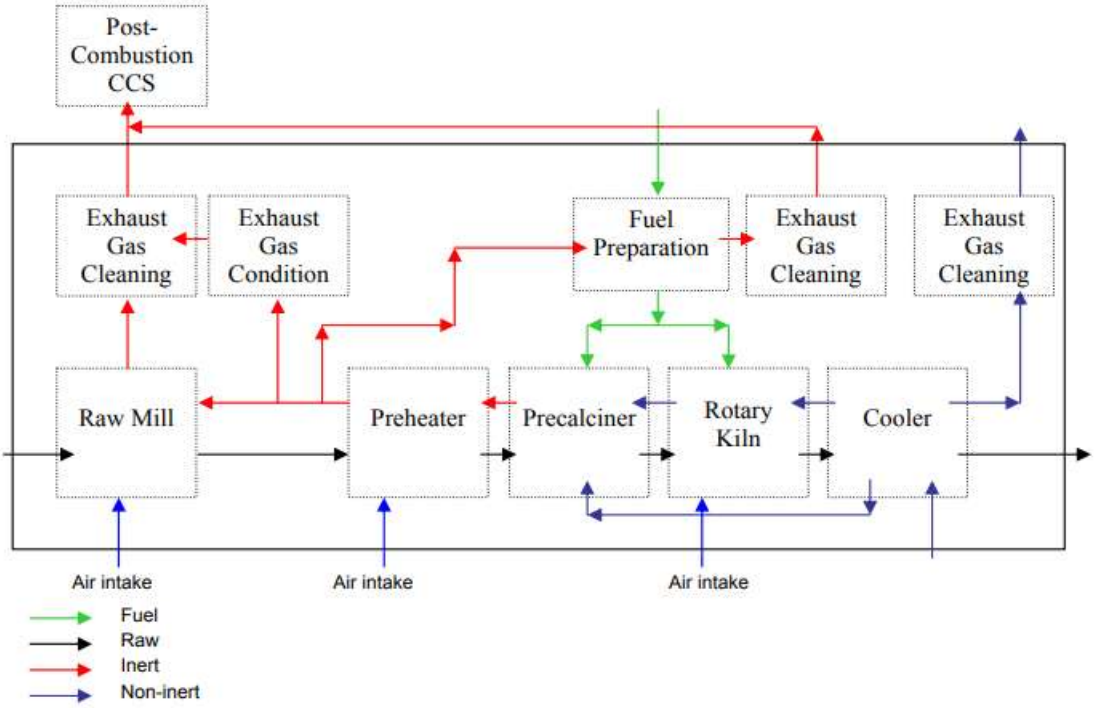

Figure 4: Post-Combustion Cement Plant Configration-1 Capture of all Flue Gases from Cement Plant in Existing Orientation [23].

Despite these challenges, post-combustion capture has been the technology of choice for many demonstration projects precisely because of its retrofitting capability. Ongoing research focuses on developing second and third generation capture technologies to improve efficiency and reduce costs, including better liquid solvents and novel membranes or microporous solids [4].

Alternative capture technologies include pre-combustion capture, which is typically operated with integrated Gasification Combined cycle (IGCC) systems, and oxy-fuel combustion, which uses pure oxygen for combustion rather than air. While these alternatives may offer certain efficiency advantages in specific context, they generally require more fundamental redesigns of the overall plant configuration, making them more suitable for new facilities rather than retrofits [4]. This distinction helps explain why post-combustion capture continues to dominate the current CCS landscape, particularly as much of the focus remains on addressing emissions from existing infrastructure.

2.5. Pipeline Transport of Supercritical CO_2

Once CO_2 is captured at emission sources, it must be transported to appropriate storage sites. Currently, pipelines represent the most common and economical means of transporting large quantities of CO_2 over long distances [13]. The physical condition most suitable for pipeline transportation in terms of pressure and temperature is the supercritical or dense phase, which offers significant advantages over gaseous transport.

Technically, CO_2 can be transported through pipelines in three stages: as a gas, as a supercritical fluid, or as a sub-cooled liquid, depending on the pressure and temperature conditions maintained during transport [13]. Gas-phase transport, however, is disadvantageous due to the low density of CO_2 in this state and the resulting high pressure drops along the pipeline. These characteristics would necessitate larger pipe diameters and more frequent compression stations, increasing both capital and operating costs [8].

Transportation in the supercritical state occurs at pressure above 7.5 MPa and temperatures above 31.1^0C (the critical point of CO_2. This phase is preferable for transportation because it is relatively stable compared to the liquid state, which minimizes cavitation problems in system components such as a booster stations and pumps [13]. The supercritical phase combines relatively high density with favorable flow characteristics, allowing for efficient transport through standard pipeline infrastructure.

Studies of pressure drop behavior in CO_2 pipelines have shown that pressure along the pipeline continuously decreases during transport. If the pressure drops below a critical threshold, CO_2 may begin to evaporate, potentially leading to two-phase flow and even pipeline blockage [13]. This means there is a maximum safe transport distance for any given pipeline configuration. For distances exceeding this maximum, booster pump stations must be installed along the pipeline route to maintain appropriate pressure conditions.

Research indicates that lower ambient temperatures are generally preferable for pipeline transport of CO_2, as they result in lower pressure drops along the pipeline length. With initial CO_2 temperatures above the supercritical point, CO_2 density can change abruptly within the pipeline once the temperature reaches the saturation point, initiating two-phase flow [13]. As ambient temperature decreases, the liquid phase flow appears at shorter distances, but the safe flow distance becomes considerably longer.

These technical considerations highlight the importance of careful pipeline design and operation for CO_2 transport. For Synergia proposed project in the Cambay Basin, which aims to transport CO_2 from multiple powerplants via an onshore pipeline network, these factors will be critical in determining the feasibility and efficiency of the overall CCS system [10]. Effective pipeline transport represents a crucial link in the CCS chain, connecting capture facilities with appropriate geological storage sites.

2.6. Booster Station Requirements for Long-Distance Supercritical CO_2 Pipelines

Supercritical CO_2 transportation through pipelines demands precise management of thermodynamic conditions to maintain operational efficiency and prevent system failures. Carbon dioxide exists in its supercritical state when maintained above its critical pressure (7.38 MPa or 73.8bar) and critical temperature (31.1^0C). In this state, CO_2 exhibits properties midway between a gas and a liquid expanding to fill its container like a gas but with a density similar to that of a liquid [14]. This higher density state proves crucial for efficient transportation, allowing for more CO_2 to be transported within pipelines of reasonable dimensions.

For practical pipeline operations, engineers typically design systems to maintain CO_2 in either supercritical or dense phase. The dense phase exists at pressure above the critical pressure but temperatures below the critical temperature, providing favorable transportation characteristics. Industry practice generally dictates maintaining minimum operating pressures well above the critical point, typically at 8.6 MPa or higher, to ensure a substantial safety margin against phase transition [15] [13].

The fundamental challenge necessitating booster stations stems from the continuous pressure drop experienced along CO_2 pipelines due to frictional losses. Research demonstrates that pressure along a pipeline continuously decreases during transport, and if allowed to drop below a critical threshold, CO_2 may begin to evaporate, potentially leading to two-phase flow and eventual pipeline blockage [16] [13]. This establishes a maximum safe transport distance for any given pipeline configuration before pressure must be increased through booster stations.

2.7. Subsurface Injection and Storage of CO_2

The final and perhaps most critical component of the CCS process is the permanent storage of captured CO_2 in deep underground geological formations. The term “subsurface storage complex” refers to the geological storage site targeted to safely and permanently store injected CO_2 underground. It includes a storage formation with at least one, or usually multiple, regionally continuous sealing formations called caprocks or seals [17].

For effective geological storage, several key requirements must be met. The storage site needs sufficient storage resource (space) to contain large amounts (millions of metric tons) of compressed CO_2. This storage resource represents a fraction of the pore volume of porous and permeable sedimentary formations available for storage [17]. The rock formation must allow CO_2 to be injected at a good rate, meaning it should have enough injectivity. It's also important that the storage site is sealed well, so the CO_2 doesn't leak to the surface or into nearby rock layers. Additionally, the formation needs to be deep enough, usually at least one kilometer underground so that the CO_2 stays in a dense or supercritical state [17].

Once injected into suitable geological formations, CO_2 is retained through several trapping mechanisms. Structural trapping represents the primary physical mechanism, where rock layers and faults within and above the storage formation act as seals, preventing CO_2 from migrating out of the storage formation. The injected supercritical CO_2, being more buoyant than other liquids present in the surrounding pore space, will migrate upward through porous rocks until it reaches and is trapped by an impermeable layer of seal rock [17].

Suitable geological formations for CO_2 storage include depleted oil and gas reservoirs, deep saline aquifers, and unamiable coal seams. Of these, deep saline aquifers offer the largest potential storage capacity globally [2]. For Synergia's proposed CCS project in the Cambay Basin, the plan involves permanent storage in a saline aquifer, representing a typical approach to geological sequestration [10].

3. METHODOLOGY

3.1. Overview of the Study

This study presents an integrated approach for CO_2 capture, transportation, and subsurface injection, focusing on a real-world scenario in Gujarat, India. This project involves designing a pipeline network to transport captured CO_2 from three cement plants to a designated injection site. The pipeline route was mapped using Google Earth to assess terrain elevations and optimal transport pathways.

Figure 5: Schematic of Pipeline Route (from Google Earth).

Table 1: Legend (Description of Pipeline)

LINE	PIPELINE	LENGTH
🟨	From Plant 1 to Well Site	63.1 km
🟦	From Plant 2 to Plant 3	13.2 km
🟥	From Plant 3 to Well Site	100 km

The study follows a structured methodology, incorporating real-world industrial data from three cement plants, each contributing towards significant towards CO_2 emissions. The captured CO_2 is then compressed, transported via a pipeline network, and injected into a depleted subsurface reservoir for long-term storage.

The methodology consists of the following key components:

3.1.1. CO_2 emission from cement plants and its calculations

The total CO_2 emissions from the three cement plants were quantified based on industry reports and real-time data. The CO_2 flow rate was calculated using standard emission factors and plant- specific production levels.

3.1.2. Post-combustion capture

A post-combustion capture system is used, where CO_2 is separated from flue gases using amine-based solvent technology. The captured CO_2 is purified to achieve the required quality for pipeline transport.

3.1.3. Compression of CO_2

CO_2 is compressed to a supercritical state to facilitate efficient transport. The compression system ensures that the CO_2 remains at a pressure above 1070 Psi to prevent phase changes during transportation.

3.1.4. Pipeline transport

A pipeline network was designed based on Google Earth terrain analysis to optimize route selection and pressure drop considerations. Pressure drops calculations include frictional losses and elevation differences along the pipeline. The pipeline network connects the cement plants to the designated injection site.

3.1.5. Subsurface injection

CO_2 is injected into a depleted reservoir located at a depth of 1350 m. Injection feasibility was assessed using Darcy's Law, considering reservoir permeability, porosity, and fracture pressure.

This study provides a comprehensive framework for implementing Carbon Capture and Storage (CCS) in cement plants, offering valuable insights into industrial-scale CO_2 sequestration and pipeline transport solutions.

The study involves designing a pipeline system to transport captured CO_2 from cement plants to an injection site, considering pressure management, flow dynamics, and storage feasibility.

3.2. CO_2 Emission from cement plants

The CO_2 emissions for three cement plants in Gujarat, India were calculated using the following equation:

$$E = P * EF \quad \text{......} (1)$$

Where:

E= Annual CO_2 emissions (tons/year)

P= Annual cement production (tons/year)

EF= CO_2 emission factor (kg CO_2/ton cement)

The CO_2 emission factor used was 565 kg CO_2 per ton of cementitious material, based on industry data provided in the JK Cement report [19].

3.2.1. Calculations [18], [19], [20]

Plant 1: J.K. Lakshmi Cement (Kalol):
- Annual production capacity: 1,000,000 tons.
- Calculated annual CO_2 Emission = 565,000 tons CO_2/year.

Plant 2: J.K. Cement (Balisinor):
- Annual production Capacity: 600,000 tons.
- Calculated annual CO_2 emissions: 339,000 tons CO_2/ year.

Plant 3: Ultratech Cement (Kovaya):
- Annual production capacity: 1,200,000 tons
- Calculated annual CO_2 Emission: 678,000 tons CO_2/year

Table 2: CO_2 Emission tons/year

CEMENT PLANT	CO_2 EMISSION TONS/ YEAR
Plant 1	565,000
Plant 2	339,000
Plant 3	678,000
Total CO_2 Emission tons/year: 1,582,000 tons CO_2/ year	

This calculation method provides an estimate of CO_2 emissions based on production capacity and an average emission factor. Future research could focus on analyzing the variations in emission factors between different cement production technologies and the impact of energy efficiency measures on reducing CO_2 emission in the cement industry.

3.3. Post-Combustion capture process in cement plants: Achieving 90% efficiency

Recent research demonstrates that post-combustion capture (PCC) technology consistently achieves 90% CO_2 capture efficiency in cement plants. This technology has emerged as the most viable option for cement industry decarbonization due to its compatibility with existing infrastructure.

3.3.1. Amine-Based capture systems

Amine-based PCC is the most mature carbon capture technology available, and it uses an amine solvent to scrub CO_2 from flue gases.

- Flue gas is fed into an absorption column where the solvent selectively removes CO_2.
- The CO_2 rich solvent is then heated in a disrober column to release pure CO_2.
- The regenerated solvent is cooled and recycled back to the absorption column.

This technology has been successfully demonstrated at Nocem's Brevik plant in Norway and is being scaled up to capture approximately 400,000 tons of CO_2 annually [21].

3.3.2. *Efficiency and energy considerations*

While 90% capture efficiency is the standard target for most projects, recent research indicates:

- GEA's pilot plant with PHOENIX Zementwerke achieved the targeted 90% CO_2 removal efficiency, noting that higher rates (approximates 95%) are technically possible but would require greater energy input and negatively impact cost efficiency [22].
- The regeneration process is energy-intensive, requiring significant thermal input for solvent regeneration, which presents economic and environmental challenges [21].
- Cement plant flue gas has a relatively high CO_2 concentration (typically 25% compared to 14% for coal fired power plants), which can improve capture efficiency [23].

3.3.3. *Recent advancements*

A 2024 study published in Environmental Science & Technology [24] has pushed the boundaries beyond the standard 90% capture:

- Kaiqi Jiyang, Hai yu, Zening Sun, Kang Li, Lidong Wang, ''*Zero-Emission Cement Plants with Advanced Amine-Based CO2 Capture*'' proposed on advancement amine-based system to achieve "zero-emission cement plants" with capture efficiency up to 99.7% [24].
- Advanced PZ-AMP (piperazine/2-amino-2-methyle-1-proponol) systems demonstrated excellent energy performance with a regeneration duty of ~2.6 GJ/ton CO_2 at 99.7% capture -39% lower than traditional MEA processes [24].
- This advancement enabled a lower CO_2 avoidance cost of $72/ ton, 18% lower than MEA-based zero-emission processes and even 16.2% lower than the standard 90% MEA processes [24].

While **90% efficiency** remains the industry benchmark for balancing technical feasibility with economic viability, these emerging technologies demonstrate the potential for even higher capture rates as the technology matures.

Based on this (capture efficiency 90%) the total amount of CO_2 that will be captured from the plants is given in Table 3 below:

Table 3: Total CO_2 Captured from Cement Plants tons/year

CEMENT PLANT	CO_2 CAPTURED TONS/YEAR
Plant 1	508,000
Plant 2	305,100
Plant 3	610,200
Total CO_2 Emission tons/year: 1,423,300 tons CO_2/ year	

3.4. CO_2 compression

CO_2 compression is a critical process in carbon capture and storage (CCS) systems, involving the compression of CO_2 from a low-pressure gas phase to a high-pressure supercritical phase for transportation and storage. This process is known as 'trans critical' compression, as it crosses the critical point of CO_2. Storage pressure typically requires 1600 psia (110 bar) locally, while pipeline specifications may need up to 2215 psia (153 bar) [25] [26]. For geological storage, a pressure range 136-204 bar is often required [27].

Multi-stage compression is commonly used, typically involving 5-6 stages [28] [27]. Interstage cooling plays a crucial role in maintaining reasonable gas temperature and protecting compressor components [29]. The compression process can consume 6-12% of a power plant's total output in CCS applications [27], making efficiency optimization important. Heat integration between compression, power production, and CO_2 capture systems is essential for improving overall efficiency [27].

Various compression technologies are employed. Integrally geared centrifugal compressors offer advantages in CO_2 applications, enabling optimization for each stage and achieving high efficiencies [27].

Inline centrifugal compressors are also used for transportation critical CO_2 compression [30]. Reciprocating compressors are suitable for lower- flow carbon sequestration applications, though they face such as pulsation control and leakage in CO_2 service [31]. Pumps are often used in final compression stage when CO_2 is in the liquid or dense phase, typically above the critical pressure of 7.38 MPa [28].

3.4.1. *Challenges in CO_2 compression*

- *Thermodynamic properties*: CO_2 has molecular weight and exhibits highly compressible behavior, especially near the critical point [27].
- *Volume reduction*: Significant volume reduction during compression requires varying impeller sizes across stages [27].
- *Heat management*: High heat of compression necessitates effective interstage cooling [29].
- *Material considerations*: Stainless steel construction is often required due to the presence of water vapor [27].
- *Pulsation and vibration*: Dense-phase CO_2 can amplify dynamic forces and transmit pulsations over long distances in reciprocating compression [31].
- *Efficiency:* Optimizing compression efficiency is crucial to minimize the energy penalty associated with CCS [25] [27].

To address these challenges, ongoing research focuses on developing more efficient compression technologies, such as shock compression systems and optimized multistage designs with integrated cooling [25] [27].

3.5. Pipeline design

3.5.1. *Velocity consideration*

Based on the reviewed literature and industry standards, the appropriate velocity range for supercritical CO_2 in pipelines is as follows:

3.5.1.1. *Recommended velocity range*

- *1-5 m/s:* This range is widely accepted for supercritical CO_2 pipelines to avoid erosion, excessive pressure drops, and operational inefficiencies [32], [33].
- *1-2 m/s:* This range is recommended for long-distance transport to minimize pressure drops and energy losses [13].
- *Up to 4.3 m/s:* The API RP14E formula calculates erosional velocity, which can be higher (e.g., 4.3 m/s) but is typically avoided to reduce wear and pressure losses [33], [34].
- *Dense phase transport:* For dense or supercritical phase transport, velocities are generally maintained between 1-3 m/s, as this ensures stable flow and minimizes operational risks [35].

The most appropriate velocity range for supercritical CO_2 pipelines based on literature is 2-4 m/s, with a maximum range of 5 m/s under specific conditions. This range balances operational efficiency, safety, and compliance with industry standards while avoiding excessive pressure drops or erosion risks.

3.5.2. *Density consideration*

The density of supercritical CO_2 is a key factor inflicting its behavior in various industrial and scientific applications. A commonly referenced value across the literature is approximately 700 kg/m^3, which is considered optimal under specific pressure and temperature conditions. This benchmark is frequently cited due to its relevance in enhancing process efficiency and stability. [36] discusses the importance of CO_2 density in various processes, including supercritical CO_2 extraction. It mentions that the density of supercritical CO_2 is often considered around 700 kg/m^3 for certain applications, while a study performed by [37] highlights the impact of CO_2 density on electrolyte extraction yield, noting that the yield increases with CO_2 density up to 700 kg/m^3.

A study [38] mentions that CO_2 density affects its sorption in polycarbonate, with significant changes observed at densities greater than 700 kg/m^3, while [39] tested CO_2 mixtures at densities near 700 kg/m^3, focusing on advanced power cycles. These studies indicate that a density of 700 kg/m^3 is a commonly referenced value for supercritical CO_2 under specific conditions, particularly in applications where density affects process efficiency or material properties.

For pipeline transportation in CCS, [36] emphasizes that supercritical CO_2 is preferred due to its high density of fluids without risk of phase change, which corresponds to a lower pressure drop along the pipeline per unit mass of CO_2 when compared to the transportation of the CO_2 as a gas. Most CO_2 pipelines operate at pressures between 8.6-15 MPa and temperatures ranging from 12.7-43.3^{0}C [36], conditions that can produce densities approaching or exceeding 700 kg/m^3.

3.5.3. *Pipeline material selection (API X65 Carbon Steel)*

Based on recent research, API X65 carbon steel is widely used for supercritical CO_2 transportation pipelines in carbon capture and storage (CCS) systems. Here are key points regarding its cost, transportation feasibility, and other considerations:

3.5.3.1. Cost effectiveness

- API X65 Carbon Steel pipe is significantly cheaper than stainless steel alternatives [40].
- For a given pressure rating X65 pipes can be made thinner than other materials, increasing carrying capacity for the same diameter [40].
- The high strength-to weight ratio of X65 Steel reduces material costs and installation expenses [40].

3.5.3.2. Transportation feasibility

- X65 Steel exhibits good resistance to crack propagation, making it suitable for high-pressure CO_2 transport [41].
- It can safely handle pressure up to 20 MPa, which is ideal for keeping CO_2 in a supercritical state [42].
- The steel's durability allows for long-distance transportation of CO_2 without frequent replacements [40].

3.5.3.3. Corrosion resistance

- In water-unsaturated supercritical CO_2, X65 steel shows low corrosion rates of about 0.015 mm/year [43].
- Corrosion rates increase in water-saturated conditions but remain manageable (<0.1 mm/year) [43].
- FBE (Fusion Bonded Epoxy) coatings can be applied to X65 pipes to enhance corrosion resistance [41].

3.5.3.4. Mechanical properties

- X65 grade offers a minimum yield strength of 448 MPa and tensile strength of 531 MPa [44].
- Its high strength allows for thinner pipe walls, reducing weight and material costs [40].

3.5.3.5. Environmental considerations

- Steel is highly recyclable, with about 70% of steel being recycled annually in North America [40].
- The production of X65 steel has become more environmentally friendly, with some plants using recycled scraps and generating lower CO_2 emissions [40].

3.5.3.6. Challenges

- Impurities in the CO_2 steam, particularly H2S, can significantly increase corrosion rates and pose safety risks [44].
- Long-term behavior under CCS storage conditions is not yet fully understood [44].
- Variations in CO_2 stream composition from different capture technologies may affect pipeline integrity [44].

While API X65 Carbon Steel offers many advantages for CO_2 transportation in CCS systems, ongoing research is needed to address corrosion issues and long-term performance under varying operation conditions

3.5.4. Requirement of booster station

Supercritical carbon dioxide pipeline transportation represents a critical component in the carbon capture and storage (CCS) value chain. For long -distance CO_2 transportation systems, particularly those extending beyond 50 kms, maintaining the CO_2 in its optimal thermodynamic state requires careful consideration of pressure maintenance systems. This comprehensive work examines the technical requirements, placement considerations, and operational parameters for booster stations in supercritical CO_2 pipeline networks, with particular attention to the unique thermodynamic challenges associated with CO_2 transport in dense phase.

3.5.5. Calculations

3.5.5.1. Mass flow rate

Mass flow rate can be calculated by the following equation:

$$\boldsymbol{m} = \frac{\textbf{Total CO2 Captured}}{\mathbf{1365*24*3600}} \left(\frac{\textbf{tons}}{\textbf{year}}\right) \ldots\ldots (2)$$

Table 4: Calculated Flow Rate Mass

PLANTS	TOTAL CO_2 CAPTURED TONS/YEAR	MASS FLOW RATE KG/S
Plant 1	508,000	16.10
Plant 2	350,100	9.68
Plant 3	610,200	19.35

3.5.5.2. Diameter

The diameter is calculated using the relationship between flowrate, velocity, and cross-sectional area. To calculate diameter for each point based on the given mass flow rates and the velocity range of **2-4 m/s** we can use the following equation:

$$\boldsymbol{D = \sqrt{\frac{4*m}{\Pi*\rho*v}}} \text{ ...... (3)}$$

Where:
D= Diameter
m= Mass flow rate
ρ= Density of CO_2 (700 kg/m^3)
v= Velocity

Table 5: Calculated Diameter at Different Velocities (i.e., 2-4 m/s)

PIPELINE 1ST FROM PLANT 1 TO WELL SITE	
Velocity	Diameter
2 m/s	0.1213 m
3 m/s	0.099m
4 m/s	0.086 m
PIPELINE 2ND FROM PLANT 2 TO PLANT 3	
Velocity	Diameter
2 m/s	0.0937 m
3 m/s	0.0765 m
4 m/s	0.0663 m
PIPELINE 3RD FROM PLANT 3 TO WELL SITE	
Velocity	Diameter
2 m/s	0.162 m
3 m/s	0.132 m
4 m/s	0.114 m

3.5.5.3. Pressure drop calculation

To calculate the pressure-drop across the pipeline we use Darcy-Weisbach equation, which is widely used in pipeline design for single phase flow (like supercritical CO_2)

The pressure drop can be calculated using Darcy-Weisbach equation:

$$\boldsymbol{\Delta P = \frac{f*L*v^2*\rho}{2*D}} \text{ ...... (4)}$$

Where:
ΔP= Pressure drops
f= Friction factor
L= Length
v= Velocity
ρ= Density of CO_2
D= Diameter

Assumptions and Input: For turbulent flow in smooth pipes f (Friction factor) is **0.02** (assumed for initial calculation.

Table 6: Data for Pressure Drop Calculation

PLANT 1 TO WELL SITE	PLANT 2 TO PLANT 3	PLANT 3 TO WELL SITE
L: 63.1 km Diameter & Velocity: Obtained different diameter result from different velocity. Density: 700 kg/m^3 Friction factor: 0.02	L: 13.2 km Diameter & Velocity: Obtained different diameter result from different velocity. Density: 700 kg/m^3 Friction factor: 0.02	L: 100 km Diameter & Velocity: Obtained different diameter result from different velocity. Density: 700 kg/m^3 Friction factor: 0.02

3.5.5.3.1. Results after calculation

Table 7: Pressure Drop at different Diameter & Velocities

PLANT 1 TO WELL SITE		
VELOCITY	DIAMETER	ΔP
2 m/s	0.1213 m	14.56 MPa
3 m/s	0.099 m	40.15 MPa
4 m/s	0.086 m	82.17 MPa
PLANT 2 TO PLANT 3		
VELOCITY	DIAMETER	ΔP
2 m/s	0.0937 m	3.94 MPa
3 m/s	0.0765 m	10.87 MPa
4 m/s	0.0663 m	22.39 MPa
PLANT 3 TO WELL SITE		
VELOCITY	DIAMETER	ΔP
2 m/s	0.162 m	17.28 MPa
3 m/s	0.132 m	47.72 MPa
4 m/s	0.114 m	98.24 MPa

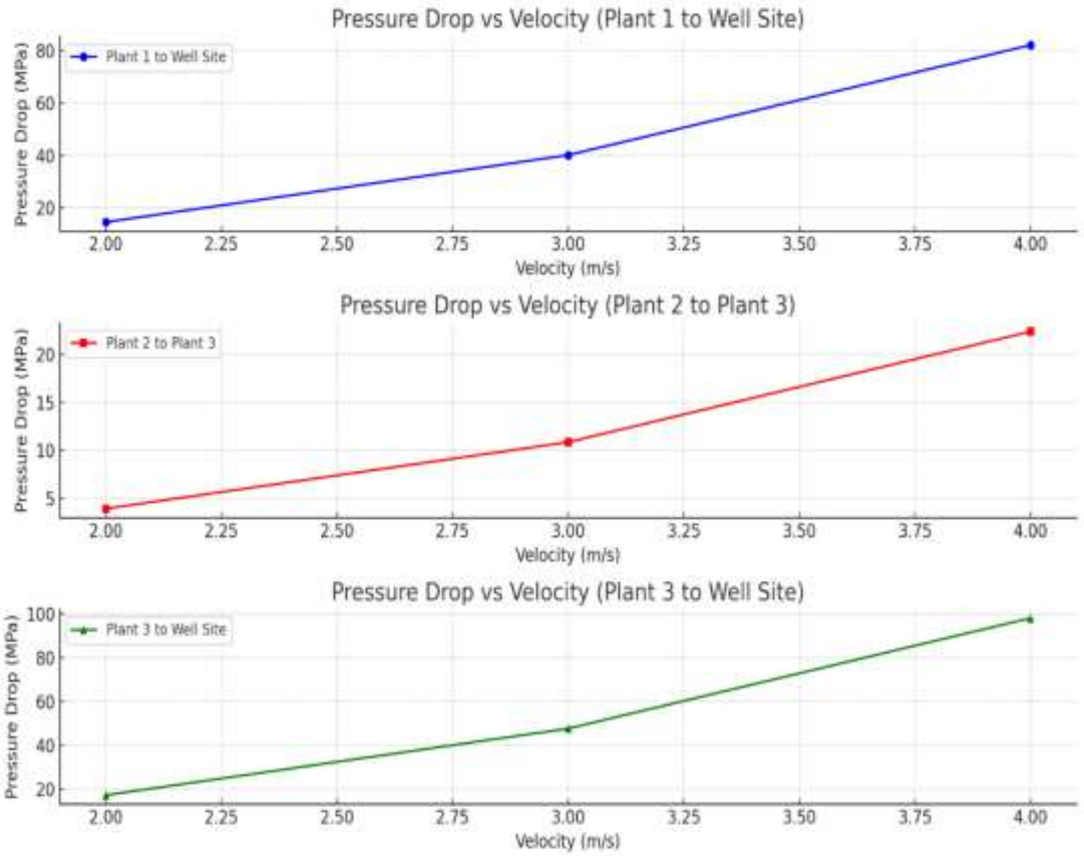

Figure 6: Variation of Pressure Drop with Flow Velocity in Pipeline.

Based on the analysis of the velocity range from 2-4 m/s, a velocity of 2 m/s is selected as an optimal choice. This selection is driven by the significantly lower pressure drop observed at this velocity, which enhances system efficiency by reducing energy consumption and operational costs. Additionally, maintaining a lower pressure drop helps minimize mechanical stress on the pipeline, contributing to improved longevity and reliability of the system.

Table 8: Pressure Increase by Booster Station and Inlet Pressure

PIPELINE	BOOSTER LOCATION (Km)	BOOSTER GAIN (MPa)	INLET PRESSURE (MPa)
1st	31.55	8.008	19.008
2nd	NA	NA	14.74
3rd	50	9.504	20.504

3.5.5.4. *Wall thickness and outer diameter*

To calculate the wall thickness for the given pipeline diameters and conditions, I used the ASME B31.4 formula for pressure design wall thickness. This is consistent with industry Standards and validated by research papers.

The wall thickness with corrosion allowance can be calculated by:

$$t = \frac{P * D}{2 * S * F * E} + C \text{ ...... (5)}$$

t= Wall thickness
P= Maximum operating pressure
D= Diameter
S= Specific yield stress of pipe material
F= Design factor
E= Longitudinal joint factor
C= Corrosion allowance

Assumptions and Inputs:
Pipe Material: API X65 Carbon Steel
Specified Minimum Yield (S): 450 MPa
Design Factor (F): 0.72 (buried pipelines)
Joint Efficiency (E): 1 (Seamless Pipe)

Outer Diameter Equation:

$$OD = ID + 2 * t \text{ ...... (6)}$$

Where:
OD = Outer diameter
ID = Inner diameter
t = Wall thickness

Table 9: Wall Thickness and Outer Diameter

PIPELINE	WALL THICKNESS (m)	OUTER DIAMETER (m)
1st	0.004	0.129
2nd	0.0021	0.0979
3rd	0.00513	0.172

3.5.6. *Pipeline design result*

3.5.7.

Table 10: Pipeline Design Result

PIPELINE 1ST	
Length	63.1 km
Internal Diameter	0.1213 m
Velocity	2 m/s
Density	700 kg/m^3
Inlet Pressure	19.008 MPa
Pressure Drop Across Pipeline	14.56 MPa

Pressure Increase by Booster Station	8.008 MPa
Wall Thickness	0.004 m
Outer Diameter	0.129 m
PIPELINE 2ND	
Length	13.2 km
Internal Diameter	0.0937 m
Velocity	2 m/s
Density	700 kg/m^3
Inlet Pressure	14.74 MPa
Pressure Drop Across Pipeline	3.94 MPa
Wall Thickness	0.0021 m
Outer Diameter	0.0979 m
PIPELINE 3RD	
Length	100 km
Internal Diameter	0.162 m
Velocity	2 m/s
Density	700 kg/m^3
Inlet Pressure	20.504 MPa
Pressure Drop Across Pipeline	17.283 MPa
Pressure Increase by Booster Station	9.504 MPa
Wall Thickness	0.00513 m
Outer Diameter	0.172 m

3.6. Subsurface injection

The selected CO_2 injection well is located in the Dholka region of Gujarat, India, targeting a depleted reservoir with the Kalol Formation of the Cambay Basin. This site was chosen based on its suitable geological characteristics, including adequate depth, pressure, and storage potential for long-term carbon sequestration. The well has been designed specifically for the injection of supercritical CO_2, as part of a Carbon Capture and Storage (CCS) initiative.

Table 11: Summary of Well

WELL OVERVIEW	
Well Type	Vertical
Total Depth	1790 m
Perforation Intervals	1345 m- 1351 m 1353 m- 1354.5 m
Perforation Density	4 spf (Shots per Foot)
Perforation Diameter	0.011176 m
Perforation Level Length	1.82 m
CASING & TUBING	
Casing Sizes	1. 13$^{3/8}$ inch (to 298 m) 2. 9$^{5/8}$ inch (to 1149 m) 3. 5$^{1/2}$ inch (to 1786 m)
Production Tubing	2$^{7/8}$ inch (to 1786 m)
RESERVOIR DATA	
Permeability	2 millidarcies
Porosity	20%
Net Pay Thickness	7 m
Drainage radius	500 m
Areal extent of the Formation	785,398.16 m^3
Fracture Gradient	0.73 psi/ft
Fracture Pressure	By Calculation: 3233.23 psi
Reservoir Pressure	By Calculation:3223.23 psi

3.6.1. *Reservoir pressure and temperature calculation:*

Pressure Calculation equation for Depletion:

$P_{depletion} = P_{initial} * (1\text{-}D)$ …… (7)

Where:

$P_{depletion}$= Pressure after depletion

$P_{initial}$ = Initial reservoir presser (before depletion)

D= Depletion fraction

Reservoir Temperature Calculation equation:

$T = T_{surface} + (\text{Geothermal Gradient} * \text{Depth in km})$ …… (8)

Where:

$T_{surface}$ = Surface temperature (42^{0}C)

Geothermal Gradient = 52^{0}C/ km

Depth = Depth of reservoir

Table 12: Depleted Reservoir Pressure and Reservoir Temperature

DEPLETED RESERVOIR PRESSURE	
50% Depletion	1616.16 psi
70% Depletion	969.97 psi
90% Depletion	323.23 psi
RESERVOIR TEMPERATURE	
Reservoir Temperature	95.35^{0}C

3.6.2. *Calculation*

Based on the data, the initial injection calculations for CO_2 storage are as follows:

3.6.2.1. *Injection interval*

The total perforation interval is 7.5m (1345 m-1351 m and 1353 m-1354.5 m)

3.6.2.2. *Formation characteristics*

- Permeability: 2md (relatively low, which may limit injection rates)
- Porosity: 20% (good for storage capacity)
- Net Pay Thickness: 7m

3.6.2.3. *Fracture gradient*

0.73 psi/ft: 16.52 kPa/m

3.6.2.4. *Maximum bottom hole pressure*

To avoid fracturing, BHP should not exceed:

BHP_{max}= Depth*fracture Gradient = 1351 m*16.52 kPa/m= **22.3 MPa**

3.6.2.5. *Injection rate calculation*

Using Darcy's Law adapted for radial flow:

$$q = \frac{2\pi hk*(BHP-Pres)}{u\times\ln\left(\frac{re}{rw}\right)} \text{ …… (9)}$$

Where:

Q= Volumetric flow rate at injection point (m^3/s)

K= permeability

h= Net pay thickness

BHP= Bottom Hole Pressure

$Pres$= Reservoir Pressure

u= CO_2 viscosity

re= drainage radius

rw=wellbore radius

By substituting all these values in Darcy's law for radial flow Equation, we get:

Q
$1.84*10^{-3}$ m^3/s
159.6 m^3/day

95,749 kg/day
95.75 tons/day

3.6.2.6. Injectivity index estimation

$$II = \frac{Q}{\Delta p} \text{ ...... (10)}$$

Where:

II= Injectivity Index.
Q= Injectivity Rate.
Δp = Pressure Difference.
II= 15.96 m^3/day/MPa.

3.6.2.7. Storage capacity estimation

Using the volumetric equation:

$$\textit{Storage capacity}= A * h * \varphi * pCO2 * E \text{ ...... (11)}$$

Where:

A= Areal extent of formation
h= thickness of formation
φ = porosity
ρCO2= density of CO_2 at reservoir conditions
E= Storage efficiency factor (typically 1-5% for saline aquifers)
Storage Capacity = 32986.8 tons.

Table 13: Subsurface Injection Calculation

Injection Interval	7.5 m
Permeability	2 md
Porosity	20%
Net pay Thickness	7 m
Fracture Gradient	16.52 kPa/m
Maximum BHP	22.3 MPa
Injection Rate	$1.84*10^{-3}$ m^3/s 159.6 m^3/day 95,749 kg/day 95.75 tons/day
Injectivity Index	15.96 m^3/day/MPa
Storage Capacity	32986.8 tons

These calculations provide essential parameters for planning CO_2 injection and storage in the depleted reservoir in which the well has been drilled. The relatively low injection rate and storage capacity suggest that this particular well may be suitable for a small scale or pilot CO_2 storage project.

3.6.3. Overall subsurface calculation result

Table 14: Overall Calculation Result from Capture to Subsurface Injection

CO_2 CAPTURED	
Plant 1	508,000 tons/year
Plant 2	305,100 tons/year
Plant 3	610,200 tons/year
Total amount of CO_2 Captured	14,23,300 tons/year
PIPELINE DESIGN RESULT	
PIPELINE 1^{ST}	
Internal Diameter	0.1213 m
Velocity	2 m/s
Inlet Pressure	17.28 MPa

Pressure Drop Across Pipeline	14.56 Mpa
Pressure Increase by Booster Station	8.008 Mpa
Wall Thickness	0.004 m
Outer Diameter	0.129 m
PIPELINE 2^{ND}	
Internal Diameter	0.0937 m
Velocity	2 m/s
Inlet Pressure	13.4 Mpa
Pressure Drop Across Pipeline	3.94 Mpa
Wall Thickness	0.0021 m
Outer Diameter	0.0979 m
PIPELINE 3^{RD}	
Internal Diameter	0.162 m
Velocity	2 m/s
Inlet Pressure	17.622 Mpa
Pressure Drop Across Pipeline	17.283
Pressure Increase by Booster Station	9.504 Mpa
Wall Thickness	0.00513 m
Outer Diameter	0.172 m
SUBSURFACE INJECTION	
Maximum BHP	20 Mpa
Injectivity Index	15.96 m^3/day/Mpa
Injection Rate	159.6 m^3/day
Storage Capacity of One Well	32986.8 tons

4. RESULTS

Table 15:

Overall Calculation Result from Capture to Subsurface Injection

CO_2 CAPTURED	
Plant 1	508,000 tons/year
Plant 2	305,100 tons/year
Plant 3	610,200 tons/year
Total amount of CO_2 Captured	14,23,300 tons/year
PIPELINE DESIGN RESULT	
PIPELINE 1^{ST}	
Internal Diameter	0.1213 m
Velocity	2 m/s
Inlet Pressure	17.28 MPa
Pressure Drop Across Pipeline	14.56 Mpa
Pressure Increase by Booster Station	8.008 Mpa
Wall Thickness	0.004 m
Outer Diameter	0.129 m
PIPELINE 2^{ND}	
Internal Diameter	0.0937 m
Velocity	2 m/s
Inlet Pressure	13.4 Mpa
Pressure Drop Across Pipeline	3.94 Mpa
Wall Thickness	0.0021 m
Outer Diameter	0.0979 m
PIPELINE 3^{RD}	
Internal Diameter	0.162 m
Velocity	2 m/s
Inlet Pressure	17.622 Mpa

Pressure Drop Across Pipeline	17.283
Pressure Increase by Booster Station	9.504 Mpa
Wall Thickness	0.00513 m
Outer Diameter	0.172 m
SUBSURFACE INJECTION	
Maximum BHP	20 Mpa
Injectivity Index	15.96 m^3/day/Mpa
Injection Rate	159.6 m^3/day
Storage Capacity of One Well	32986.8 tons

5. Validation

5.1. Validation of CO_2 pipeline design and subsurface injection parameters against real-world CCS projects and research

CCS pipeline design and subsurface injection calculations align well with established research and operational CCS projects. Below is the validation of your results using the provided search results and real-world CCS data:

Table 16: Pipeline Design Validation Key Parameters

PARAMETERS	OBTAINED VALUE	INDUSTRY STANDARD/ REFERENCES	VALIDATION
Velocity (2m/s)	2m/s (all Pipelines)	API-RP-14E erosional velocity limit: 4.3 m/s [33]. Lower velocity reduces erosion risks.	Valid
Pressure Drop	0.23-0.30 MPa/km	Typical Range: 0.1-0.3 MPa/km [33]	Valid
Material (API X65)	PSL2 (Sour Service Grade	API 5L X65 PSL2 recommended for $CO2_2$ pipelines [45]. Complies with NACE MR 0175 for H_2S resistance	Valid
Wall Thickness	4-8 mm	Calculated using Barlow's formula [46]. it matches ASME B31.4 standards	Valid
Outer Diameter	0.129-0.172 m	*OD = ID+ 2t.* Matches standard pipeline sizing [47]	Valid

5.1.1. Booster station safety margins

- *Pressure increases:* 8-9 MPa aligns with industry practice to maintain supercritical CO_2 conditions [46].
- *Booster spacing:* ~50 km intervals (pipeline 1st: 31.5 km Pipeline 3rd:50 km) match recommendations for CO_2 pipelines [33].

Table 17:

Subsurface Injection Validation Key Parameters

PARAMETERS	OBTAINED VALUE	INDUSTRY STANDARD/REFERENCE	VALIDATION
Injectivity Index	15.96 m^3/day/MPa	Typical range: 10-20 m^3/day/MPa [48]	Valid
Injection Rate	159.6 m^3/day	Matches Computational model [48].	Valid
Storage Capacity	32,986.8 tons/well	Aligns with Cambay Basin Studies [49] (5.99 MMt in 50 Km^2 area)	Valid

Max BHP	20 MPa	Below Fracture Pressure (22.3 MPa). Compiles with geo-mechanical safety limits [48]	Valid

5.1.2. CO_2 stream quality

- Pipeline design assumes pure CO_2. For compliance with NETL guidelines [49]:
- **H_2O:** <500 ppm
- **H_2S:** <200 ppm
- **O_2:** <100 ppm

5.2. Critical observation

5.2.1. Pipeline safety

- Velocity 2m/s is conservative compared to erosional limits (4.3 m/s), reducing wear risks [33].
- Booster stations maintain supercritical conditions [46], crucial for avoiding phase changes

5.2.2. Subsurface risks

- Storage capacity per well (~33 kt) is low. For 14.23 Mt/year, 430+ wells would be required. This aligns with Cambay Basin's multi-well strategy [49].

5.2.3. CO_2 impurities

- This design assumes pure CO_2. For compliance with NETL guidelines [49], gas treatment units must limit impurities (e.g., H_2O, 500 ppm).

This design aligns with industry standards for material selection, pressure safety, and injectivity. This work provides a scalable framework for mid-sized CCS projects, emphasizing the need for adaptive designs in heterogeneous reservoirs.

6. CONCLUSION

This Research work presents a comprehensive analysis of an integrated Carbon Capture and Storage (CCS) system designed for cement plants in Gujarat, India, focusing on the capture, transportation, and subsurface injection of CO_2. The study demonstrates the technical feasibility of implementing CCS in India's cement sector, providing a scalable framework that could significantly contribute to national carbon reduction targets.

The detailed modeling and analysis conducted in this study demonstrate that Carbon Capture and Storage represents a technically viable pathway for decarbonizing India's cement industry, though significant challenges remain in scaling the technology to meet climate goals. Our integrated design approach, encompassing CO_2 capture from three cement plants, transportation via an optimized pipeline network, and subsurface injection into the Cambay Basin, provides valuable insights for future CCS implementation in India's industrial sector.

The post-combustion capture system utilizing amine-based technology was found to be the most suitable approach for existing cement plants, achieving 90% capture efficiency while balancing technical feasibility with economic viability. This approach allows for retrofitting existing facilities without fundamental redesigns, an important consideration for India's established cement infrastructure. While higher capture rates (up to 99.7%) are technically possible, as demonstrated by recent advances in PZ-AMP systems, the 90% benchmark represents an appropriate target for initial deployment.

Pipeline design calculations revealed that a velocity of 2 m/s represents the optimal operating condition for supercritical CO_2 transport, significantly reducing pressure drop compared to higher velocities. This conservative approach enhances system efficiency while minimizing mechanical stress on the pipeline infrastructure. The selection of API X65 Carbon Steel as the pipeline material balances cost-effectiveness with the necessary mechanical properties for safe CO_2 transport, though long-term performance under varying operational conditions requires continued monitoring.

The strategic placement of booster stations at approximately 50 km intervals ensures the maintenance of supercritical conditions throughout the pipeline network, preventing phase changes that could compromise system integrity. The calculated pressure increases of 8-9 MPa align adequate safety margins for reliable operation.

For subsurface injection, calculations based on Darcy's Law indicate significant limitations in the storage capacity of individual wells. With an estimated capacity of approximately 33,000 tons per well and an injectivity index of 0.056 Mt/MPa/year, the implementation of a full-scale CCS system would require more wells to accommodate the total captured CO_2 from the cement plants. This finding aligns with the multi-well strategy proposed for the Cambay Basin and highlights the importance of comprehensive reservoir characterization for successful CO_2 storage.

7. LIMITATIONS AND FUTURE WORK

A significant limitation of our study is the focus on technical feasibility without detailed economic analysis. While technical parameters have been calculated, the economic viability of implementing CCS in India's cement sector remains a critical question that demands further investigation. The capital and operational costs associated with capture systems, pipeline infrastructure, and injection wells may present significant barriers to deployment, potentially requiring policy support mechanisms such as carbon pricing or tax incentives.

Future research should expand on this work by incorporating detailed economic modelling to determine the cost of CO_2 abatement through CCS in India's specific context. Additionally, investigations into potential utilization pathways for captured CO_2 could enhance project economics while delivering additional environmental benefits. The integration of CCS with renewable energy sources to power compression and capture processes also present an important avenue for reducing the overall carbon footprint of the system.

This study provides a scalable framework for mid-sized CCS projects in India's industrial sector, emphasizing the need for adaptive designs that can accommodate the unique characteristics of emission sources and geological storage sites. As India continues to develop its approach to climate mitigation, CCS technology offers a pathway to significant emission reductions in hard-to-abate sectors like cement production, contributing to both national and global carbon reduction goals.

8. Novel Contribution of This Study

While several CCS Projects worldwide focus on CO_2 capture and storage from power plants and natural gas processing facilities, limited research exists on integrating CCS into the cement industry, particularly in India's industrial sector. This study presents a first-of-its-kind engineering framework for CO_2 capture, transportation, and subsurface injection tailored to cement plants in Gujarat, India. The key contributions of this research include:

- *Sector-Specific Application*: unlike global CCS projects such as Sleipner (Norway) or Gorgon (Australia), which primarily target power plants and natural gas fields, this study focuses on hard-to-abate cement emissions, which cannot be eliminated through conventional decarbonization strategies.
- *First Detailed Pipeline Transport Model for Indian Cement CCS*: A customized CO_2 pipeline network was designed using Google Earth terrain mapping, incorporating pressure drop analysis, booster station placement, and material selection to optimize transportation efficiency.
- *Validation of CO_2 Storage Feasibility in the Cambay Basin*: this study provides a quantitative reservoir analysis for a depleted oil and gas reservoir in India, including injectivity index calculations (15.96 m^3/day/MPa), storage capacity estimation (32,986 tons per well), and fracture pressure validation (22.3 MPa max BHP).
- *Optimization of Supercritical CO_2 Injection*: The study evaluates the behavior of supercritical CO_2 in low-permeability Indian reservoirs (2 mD), ensuring safe storage while maintaining reservoir integrity.
- *Real Industrial Data Utilization*: unlike previous studies that rely on theoretical emission factors, this research uses actual CO_2 emission data from three major cement plants, improving the real-world applicability of the findings.

By integrating these technical advancements, this study bridges the gap between theoretical CCS modeling and real-world industrial deployment, offering a scalable and efficient solution for decarbonizing cement production in India and beyond.

8.1. Study contribution

Carbon Capture and Storage represents a crucial technological pathway for addressing climate change, particularly for hard-to-abate sectors like cement production where few alternative mitigation options exist. The technology encompasses three integrated components- capture, transport, and storage-each with established methods and ongoing innovations to improve performance and reduce costs. While CCS deployment faces challenges in scaling to meet climate goals, recent acceleration in project development suggests growing recognition of its essential role in comprehensive climate strategy.

In the Indian context, CCS remains at a relatively early stage but shows increasing momentum through initiatives like the proposed Cambay Basin project. This project, if successful, could establish an important model for integrating capture from multiple industrial sources with pipeline transport and geological storage. The technical feasibility of each component from post-combustion capture at cement plants to pipeline transport of supercritical CO_2 to injection and storage in deep saline formations has been demonstrated globally, though challenges remain in creating the financial and regulatory frameworks to support widespread deployment.

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