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Techno-Economic Design of Onshore Gas Pipelines with High CO_2 and H_2S Content

Joko Pamungkas[1], Indrianti Pramadewi[2], Yulius Deddy Hermawan[3], Avido Yuliestyan[3], Yusmardhany Yusuf[3], Aditya Kurniawan[3], Muhammad Redo Ramadhan[3], Heni Anggorowati[3], Perwitasari[3], Mutiara Wulandari[3], and Muhammad Daffa Lazuardi[3]

[1]Departement of Petroleum Engineering, Faculty of Mineral Technology and Energy,
Universitas Pembangunan Nasional "Veteran" Yogyakarta.
Padjadjaran Street SWK 104 (North Ring Road) Condongcatur Sleman DI Yogyakarta, 55283, Indonesia.

[2]PetroChina International Jabung Ltd.
Menara Kuningan GF, 19th - 27th floor, HR. Rasuna Said Street Blok X-7 Kav. 5, South Jakarta, 1294, Indonesia.

[3]Departement of Chemical Engineering, Faculty of Industrial Engineering, Universitas Pembangunan Nasional "Veteran" Yogyakarta.
Padjadjaran Street SWK 104 (North Ring Road) Condongcatur Sleman DI Yogyakarta, 55283, Indonesia.

Corresponding author: Joko Pamungkas (joko.pamungkas@upnyk.ac.id)

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ABSTRACT - This study develops a simulation-based techno-economic framework for designing an onshore gas trunkline system to accommodate production from newly developed wells in the X and Y Fields. The system transports 35 MMSCFD of untreated natural gas containing approximately 60 mol% CO_2 and 70 ppm H_2S, where high acid gas content and declining wellhead pressure impose constraints on pressure delivery, flow velocity, material selection, and lifecycle cost. Steady-state hydraulic simulations were performed using UniSim R490 to evaluate early- and mid-life production scenarios based on pressure drop and erosional velocity ratio (EVR) in accordance with API RP 14E. Comparative analysis of candidate pipeline diameters shows that a 12-inch trunkline maintains a minimum delivery pressure of 50 psig while keeping EVR below unity, thereby satisfying hydraulic and mechanical integrity requirements without excessive recompression. The integration of an onshore booster compressor mitigates reservoir pressure decline and sustains gas transport to the central processing facility. Material selection analysis identifies duplex stainless steel and SS 316 as technically viable options for CO_2-H_2S service under controlled operating conditions. Techno-economic evaluation indicates that the selected configuration minimizes total lifecycle cost relative to alternative designs, with estimated CAPEX of USD 228.43 million and annual OPEX of USD 142.19 million. The results demonstrate that integrated hydraulic optimization, sour-service material selection, and economic assessment provide a robust and economically optimized design approach for onshore sour gas pipeline systems.

Keywords: onshore gas pipeline, sour gas transportation, techno-economic design, erosional velocity ratio (EVR), booster compression.

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INTRODUCTION

Onshore gas field developments increasingly encounter gas streams with elevated carbon dioxide (CO_2) concentrations and trace hydrogen sulfide (H_2S), particularly during the early opening of new wells and the subsequent pressure-decline phase of reservoir production. High CO_2 content, typically expressed in mol%, significantly reduces gas heating value and alters thermophysical properties, while H_2S, even at ppm levels, introduces critical safety and corrosion risks that directly influence pipeline material selection and operating limits (Agiaye & Othman, 2016; Meisingset et al., 2016; NACE MR0175/ISO 15156, 2020; Ji et al., 2024). These characteristics impose stringent requirements on hydraulic performance, erosion control, and integrity management in onshore trunklines transporting untreated wellhead gas to central processing facilities.

Recent advances in pipeline and energy infrastructure design increasingly emphasise integrated techno-economic optimisation to address the complex interplay between hydraulic behaviour, compression strategy, material durability, regulatory considerations, and lifecycle cost. Peletiri et al. (2018) reviewed CO_2 pipeline design and highlighted the importance of thermodynamic modelling, hydraulic constraints, and material qualification in high-CO_2 transport systems. Andreasen et al. (2025) further demonstrated that optimisation of pressurisation strategies significantly influences pipeline feasibility and cost efficiency. In the broader energy context, techno-economic analyses have shown that infrastructure configuration and fiscal frameworks critically determine project viability (Hayat et al., 2024; Sugihardjo et al., 2024). Recent studies in Indonesia have also emphasised the importance of integrating fiscal, engineering, and economic considerations in CO_2-rich and energy transition projects (Ramadhani et al., 2025; Supriyadi et al., 2025). These works collectively underline that pipeline design in high-CO_2 environments requires a systematic framework that simultaneously addresses engineering performance and economic sustainability.

In onshore gas gathering and trunkline systems, declining wellhead pressure remains a primary operational challenge because it directly limits deliverability and can induce excessive velocity, unstable flow regimes, or compression inefficiencies if pipeline diameter and booster strategy are not properly designed (Economides and Kappos, 2009). Engineers therefore rely on hydraulic evaluation to ensure that pressure drop, gas velocity, and erosional velocity ratio (EVR) remain within acceptable limits throughout the production lifecycle. API RP 14E continues to serve as a widely applied preliminary screening criterion for erosion risk in gas pipelines, particularly during early design stages, despite its limitations for multiphase flow conditions (API RP 14E, 2018).

Material selection further complicates the design of sour gas pipelines. CO_2-dominated gas streams promote general corrosion, while H_2S introduces risks of sulfide stress cracking and hydrogen embrittlement, requiring compliance with sour-service material standards such as API 5L, ASME B31.3, and NACE MR0175/ISO 15156 (API 5L, 2018; ASME B31.3, 2022; NACE MR0175/ISO 15156, 2020). The selection of corrosion-resistant alloys must therefore balance technical suitability with economic feasibility, particularly for long onshore trunklines where material costs significantly affect project viability.

Previous studies have examined individual aspects of gas pipeline design, including hydraulic optimisation (Zhang et al., 2006), compressor placement (Asyari, 2018), and corrosion behaviour in CO_2-H_2S environments (Wang and Yang, 2024). However, most existing studies treat hydraulic design, material selection, and economic evaluation as separate analyses. Comprehensive integration of these dimensions within a unified decision framework tailored to onshore trunklines transporting high-CO_2 gas during new well development remains limited. Moreover, recent techno-economic studies in energy infrastructure have highlighted the need for holistic evaluation frameworks that link engineering performance with lifecycle cost and system reliability (Hasan et al., 2023; Andreasen et al., 2025).

This study addresses these gaps by developing an integrated simulation-based design and techno-economic evaluation of an onshore gas trunkline system serving newly developed wells with high CO_2 and H_2S content. The study aims to determine an optimal pipeline diameter, material specification, and booster configuration that jointly satisfy hydraulic stability, erosion control, and economic performance under early- and mid-life production conditions. By combining hydraulic simulation, sour-service material assessment, and lifecycle cost analysis, this work provides a systematic engineering framework for designing cost-efficient and technically robust onshore gas pipeline systems under high-CO_2 operating conditions.

METHODOLOGY

Figure 1 illustrates the engineering design methodology used in this study. The process begins with data collection and analysis, including well and pad information, flow properties, and gas composition. These inputs serve as the foundation for pipeline process simulations conducted in Unisim under various production and outlet pressure scenarios. The simulation results are then used for pipeline sizing to determine the optimum diameter, length, and EVR while ensuring compliance with safety and performance criteria. Based on the selected pipeline configuration, suitable materials are identified to handle high CO_2 and H_2S content. Finally, a techno-economic analysis is performed to estimate the Capital Expenditure (CAPEX) and Operational Expenditure (OPEX), allowing a comprehensive evaluation of both technical performance and economic feasibility.

System description and design basis

This study evaluates an onshore gas trunkline system designed to transport untreated single-phase wellhead gas from newly developed wells in the X and Y Fields to a central gas processing facility. The gas contains approximately 60 mol% CO_2 with H_2S at ppm levels and is produced under declining wellhead pressure typical of early- to mid-life field operation. Because no upstream acid gas removal is assumed, the design prioritizes hydraulic performance, erosion control, and sour-service material selection. The design basis follows API RP 14E for erosion screening, API 5L and ASME B31.3 for pipeline and piping design, and NACE MR0175/ISO 15156 for material qualification in CO_2–H_2S environments (API RP 14E, 2018; API 5L 2018; ASME B31.3, 2022; NACE MR0175/ISO 15156, 2020).

To evaluate the impact of reservoir depletion on pipeline performance, this study defines early-life and mid-life production stages and analyzes three operating cases: early-life production in 2029, mid-life production of Field X in 2031, and mid-life production of Field Y in 2037, with target gas rates of 5 MMSCFD and 30 MMSCFD, respectively. Early-life operation reflects higher wellhead pressures and stable flow conditions, while mid-life operation represents reservoir depletion with reduced wellhead pressure and increased hydraulic constraints. The analysis applies outlet pressure levels of 400, 200, 100, and 50 psig to represent practical operating envelopes in onshore gas transmission systems, where 400 psig corresponds to typical inlet pressure requirements of central processing facilities, intermediate levels capture progressive pressure losses, and 50 psig defines the minimum acceptable delivery pressure for stable gas transport. These pressure levels enable systematic assessment of pressure drop, gas velocity, erosion risk, and booster compression requirements across production stages. Each case incorporates changes in well availability and booster compression deployment based on confidential production data provided by Company "A," including flow rates, gas composition, H_2S concentration, and wellhead pressure and temperature (Pamungkas et al. 2024).

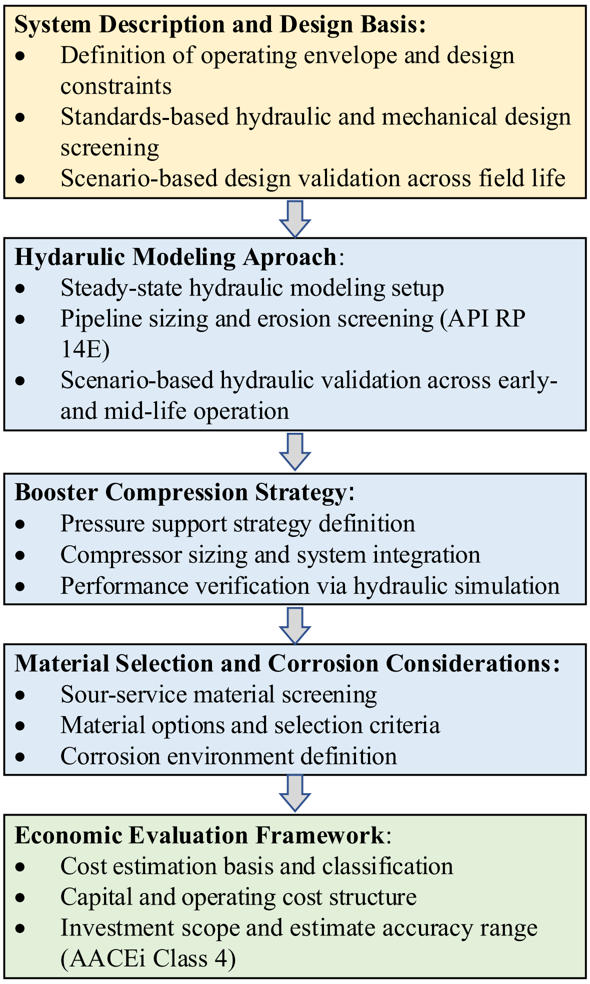


Figure 1. Integrated engineering design methodology for onshore sour gas trunkline development.

Hydarulic modeling aproach

This study applies steady-state gas hydraulic simulations using UniSim R490 to evaluate pressure drop, gas velocity, and EVR for an onshore trunkline system extending from the wellhead to the pad station, through the gathering system, and onward to the terminal facility, as illustrated in **Figure 2**. **Tables 1** and **2** provide summaries of the flowline/padline and trunkline data. The model employs the Peng–Robinson equation of state because it reliably predicts the thermodynamic behavior of high-CO_2 and H_2S-containing gas mixtures (Jaubert et al. 2005; Wongsri and Hermawan 2005; Costa et al. 2014; Kristanto and Hermawan 2020; Rahman and Anjana 2021; Windyaningrum et al., 2025). Pipeline diameter and length are determined from gas flow rate, delivery pressure, and operating temperature, while sizing explicitly accounts for pressure drop and EVR, which directly influence material selection, capital cost, and operational safety. Pressure drop represents frictional energy loss along the pipe wall and depends on flow rate, pressure, pipe roughness, length, diameter, temperature, and fluid viscosity (Syarif 2004; Jalaluddin et al. 2019). The erosion criterion follows API RP 14E, where the maximum allowable velocity, V_e (ft/s), is defined as:

$$V_e = C/\sqrt{\rho_m} \tag{1}$$

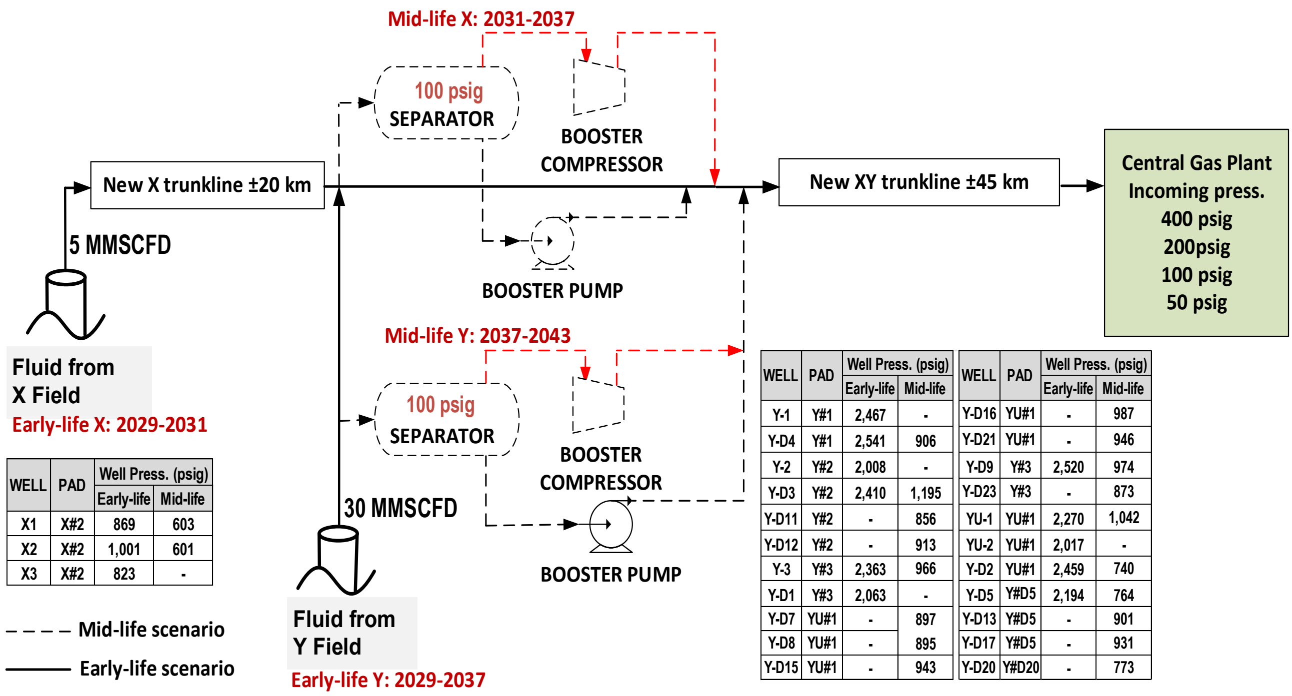
with $C = 100$, empirical constant (ft/s $\cdot \sqrt{\text{lb/ft}^3}$) and ρ_m representing the mixture density (lb/ft^3). This conservative screening limit ensures mechanical integrity for continuous operation under corrosive, solid-free gas conditions. The simulations evaluate early-life and mid-life production scenarios with declining wellhead pressure to identify the minimum trunkline diameter that simultaneously satisfies pressure delivery and erosion constraints.

Booster compression strategy

To mitigate pressure decline during mid-life operation, the study evaluates a booster compressor installed at the trunkline inlet. The booster increases inlet pressure to maintain target delivery pressure at the processing plant without exceeding erosion velocity limits. Compressor sizing follows standard gas compression principles, with performance evaluated through hydraulic simulation rather than transient dynamic analysis.

Material selection and corrosion considerations

Material selection focuses on resistance to CO_2 corrosion and H_2S-related cracking mechanisms. Candidate materials include carbon steel with



WELL	PAD	Well Press. (psig)	
		Early-life	Mid-life
X1	X#2	869	603
X2	X#2	1,001	601
X3	X#2	823	-

WELL	PAD	Well Press. (psig)		WELL	PAD	Well Press. (psig)	
		Early-life	Mid-life			Early-life	Mid-life
Y-1	Y#1	2,467	-	Y-D16	YU#1	-	987
Y-D4	Y#1	2,541	906	Y-D21	YU#1	-	946
Y-2	Y#2	2,008	-	Y-D9	Y#3	2,520	974
Y-D3	Y#2	2,410	1,195	Y-D23	Y#3	-	873
Y-D11	Y#2	-	856	YU-1	YU#1	2,270	1,042
Y-D12	Y#2	-	913	YU-2	YU#1	2,017	-
Y-3	Y#3	2,363	966	Y-D2	YU#1	2,459	740
Y-D1	Y#3	2,063	-	Y-D5	Y#D5	2,194	764
Y-D7	YU#1	-	897	Y-D13	Y#D5	-	901
Y-D8	YU#1	-	895	Y-D17	Y#D5	-	931
Y-D15	YU#1	-	943	Y-D20	Y#D20	-	773

Figure 2. Hydraulic model scenarios.

corrosion allowance and corrosion-resistant alloys such as duplex stainless steel and austenitic stainless steel. Selection criteria include compliance with NACE MR0175/ISO 15156, resistance to sulfide stress cracking, availability, constructability, and lifecycle cost implications (NACE MR0175/ISO 15156, 2020).

External corrosion considerations reflect an onshore environment and exclude marine exposure, eliminating chloride-induced seawater corrosion mechanisms. Internal corrosion assessment considers average CO_2 and H_2S partial pressures under steady operating conditions.

Economic evaluation framework

This study evaluates project economics by estimating capital expenditure (CAPEX) and annual operating expenditure (OPEX) using deterministic cost methods appropriate for concept and pre-FEED assessment. The evaluation adopts the cost estimate classification matrix in Table 3, adapted from the American Association of Cost Engineers International (AACEi) Recommended Practice No. 18R-97, which categorizes estimate classes based on project definition maturity, intended use, estimation methodology, and expected accuracy range (AACEi, 2020). Consistent with early-stage onshore gas pipeline development, the analysis applies a Class 4 (feasibility study) estimate corresponding to a project definition maturity of 1%–15% and developed using equipment-factored and parametric models (Pamungkas et al. 2024).

CAPEX includes pipeline materials, installation, and compression facilities, while OPEX accounts for compression energy and routine operating requirements. The Class 4 estimate carries an expected accuracy range of –15% to –30% on the low side and +20% to +50% on the high side, reflecting uncertainty inherent in preliminary design. The total investment cost equals the sum of fixed capital and working capital, where fixed capital comprises direct and indirect costs associated with Engineering, Procurement, Construction, and Installation (EPCI) activities, including project management, engineering, procurement, fabrication, installation, pre-commissioning, and start-up supervision.

Table 1. Summaries of the flowline/padline data.

Well	Pad	Well Press. (psig)		Rate (MMSCFD)		Pipe length (m)		Pipe diameter (in)	
		Early-life	Mid-life	Early-life	Mid-life	Early-life	Mid-life	Early-life	Mid-life
Flowline/Padline in X Field									
X1	X#2	869	603	1.47	1.99	1,906	1,906	4	4
X2	X#2	1,001	601	1.11	3.07	140	140	4	4
X3	X#2	823	-	2.49	-	130	-	4	-
Flowline/Padline in Y Field									
Y-1	Y#1	2,467	-	0.26	-	183	-	4	-
Y-D4	Y#1	2,541	906	3.20	1.80	185	185	4	4
Y-2	Y#2	2,008	-	1.47	-	70	-	4	-
Y-D3	Y#2	2,410	-	2.08	-	70	-	4	-
Y-D11	Y#2	-	856	-	0.76	-	70	-	4
Y-D12	Y#2	-	913	-	1.35	-	402	-	4
Y-3	Y#3	2,363	966	1.17	0.95	35	35	4	4
Y-D1	Y#3	2,063	911	4.09	3.11	1,496	1,496	4	4
Y-D7	YU#1	-	897	-	0.88	-	625	-	4
Y-D8	YU#1	-	895	-	3.89	-	1,644	-	4
Y-D15	YU#1	-	943	-	3.59	-	85	-	4
Y-D16	YU#1	-	987	-	1.14	-	85	-	4
Y-D21	YU#1	-	946	-	1.27	-	85	-	4
Y-D9	Y#3	2,520	974	2.63	1.07	35	35	4	4
Y-D23	Y#3	-	873	-	0.42	-	2,345	-	4
YU-1	YU#1	2,270	1,042	3.57	2.37	88	87	4	4
YU-2	YU#1	2,017	1,148	3.59	2.61	104	104	4	4
Y-D2	YU#1	2,459	740	4.00	1.38	1,496	1,496	4	4
Y-D5	Y#D5	2,194	764	4.00	0.79	6,632	6,632	4	4
Y-D13	Y#D5	-	901	-	1.31	-	160	-	4
Y-D17	Y#D5	-	931	-	0.80	-	960	-	4
Y-D20	Y#D20	-	773	-	0.56	-	4,032	-	4

Table 2. Summaries of the trunkline data.

Trunkline	Length (km)	Diameter (in)	Rate (MMSCFD)	
			Early-life	Mid-life
X	±20	6	5	5
XY	±45	12	30	30
		total	**35**	**35**

Table 3. Cost estimate classification matrix (AACEi 2020).

Estimate class	*Primary characteristic*	*Secondary Characteristic*		
	Maturity level of project definition deliverables Expressed as % of complete definition	**End usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Range** Typical variation in low and high rang[a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization	Semi-detailed unit costs with assembly	L: -10% to -20% H: +10% to +30%

Table 3. Cost estimate classification matrix (AACEi 2020) (continued)

Estimate class	*Primary characteristic* **Maturity level of project definition deliverables** Expressed as % of complete definition	*Secondary Characteristic* **End usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Range** Typical variation in low and high rang[a]
		or control	level line items	
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] the state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/– value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typical at a 50% level of confidence) for given scope.

Source *Adapted from AACEi Recommended Practice No. 18R-97 (AACEi, 2020). Terminology and formatting have been revised for clarity.*

RESULTS AND DISCUSSION

Hydraulic performance under early- and midlife production conditions

The hydraulic simulations confirm that pipeline diameter governs pressure delivery and gas velocity for the onshore trunkline transporting high -CO_2 gas. Under early-life production conditions, when wellhead pressure remains relatively high, smaller diameters satisfy minimum delivery pressure requirements at the central gas plant (CGP); however, declining wellhead pressure during midlife operation significantly increases pressure losses and constrains smaller pipelines.

As shown in Figure 3, the relationship between trunkline diameter and inlet pressure demonstrates that a 12-inch pipeline provides a stable hydraulic operating point across all evaluated outlet pressures. At this diameter, the trunkline maintains an inlet pressure of approximately 650 psig for outlet pressures of 400, 200, 100, and 50 psig, indicating that frictional pressure losses remain well controlled. For smaller diameters, inlet pressure increases sharply, reflecting higher frictional resistance and reduced hydraulic margin, particularly under lower outlet pressure conditions. Conversely, increasing the diameter beyond 12 inches yields diminishing reductions in inlet pressure, indicating limited incremental benefit relative to additional capital cost. The convergence of inlet pressure values at the 12-inch diameter across all outlet pressure scenarios confirms that this configuration effectively decouples upstream pressure requirements from downstream operating conditions, thereby providing sufficient margin to accommodate reservoir pressure decline while maintaining stable gas delivery to the processing facility.

In addition to pressure delivery performance, pipeline sizing was constrained by the maximum allowable erosional velocity defined by API RP 14E. The allowable velocity was calculated using Equation (1), where the empirical constant $C = 100$ corresponds to conservative continuous-service operation and yields velocity in ft/s when mixture density is expressed in lb/ft³. This criterion provides a screening-level limit to mitigate erosion and long-term integrity degradation in gas pipelines. As shown in Figure 4, candidate trunkline diameters below 12-inch exceed or approach the EVR threshold of unity under low outlet pressure conditions, indicating unacceptable erosion risk. In contrast, the 12-inch trunkline maintains gas velocity below the allowable limit across all evaluated outlet pressures and production stages, confirming that erosion constraints, rather than pressure drop alone, govern the minimum feasible pipeline diameter. Figure 4 shows an inverse relationship between EVR and outlet pressure. At a delivery pressure of 50 psig, the 12-

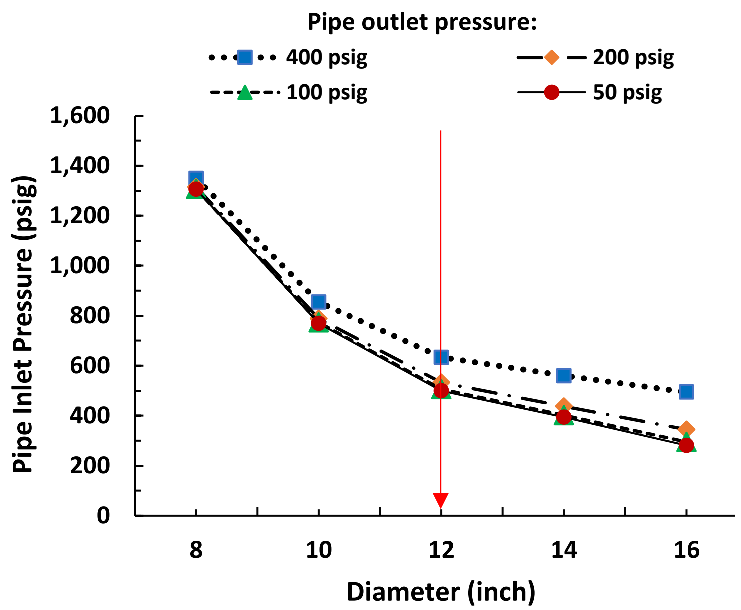


Figure 3. Hydraulic simulation results of XY trunkline: diameter vs pipe inlet pressure.

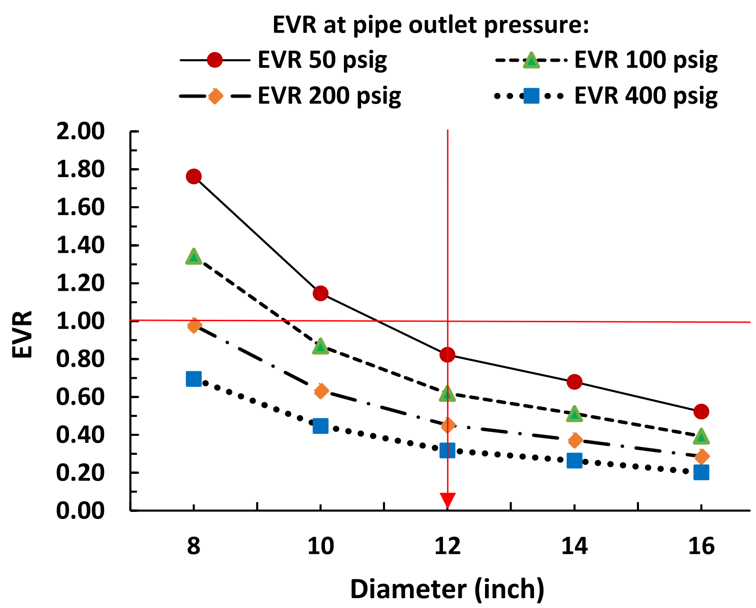


Figure 4. Hydraulic simulation results of XY trunkline: diameter vs EVR

inch trunkline maintains EVR below unity while limiting the total pressure drop to approximately 600 psig, which can be accommodated by the available wellhead pressure and a single booster compression stage.

Effectiveness of booster compression for pressure management

The introduction of a booster compressor at the trunkline inlet significantly improves system hydraulic stability during mid-life operation. Without compression, declining wellhead pressure reduces flow deliverability and narrows the operational envelope. The booster increases inlet pressure sufficiently to restore outlet pressure while maintaining gas velocity within acceptable erosion limits. Table 4 shows the quantitative impact of booster compression on pipeline sizing. Simulation results quantitatively demonstrate that booster compression enables the system to sustain the design throughput of 35 MMSCFD without increasing trunkline diameter. Under mid-life operating conditions and a delivery pressure of 50 psig, simulations indicate that a 12-inch trunkline without booster compression would require inlet pressures exceeding 900 psig and produce EVR values approaching or exceeding unity, indicating hydraulic and erosion constraints. Increasing the trunkline diameter to 14-inch reduces these constraints but significantly increases capital cost. In contrast, introducing booster compression reduces the required inlet pressure to approximately 650 psig while maintaining EVR below unity at a 12-inch diameter. This represents an inlet pressure reduction of approximately 250 psig compared with the non-boosted case and eliminates the need for diameter upscaling. These results confirm that integrating booster compression with pipeline sizing minimizes capital expenditure associated with larger diameters while preserving hydraulic reliability, supporting the coupled design approach recommended by Economides & Kappos (2009).

Erosion control and velocity management

Gas velocity emerges as a critical design constraint for high-CO_2 gas transport because elevated density and altered flow properties can increase erosive potential. The EVR analysis confirms that pipeline diameters smaller than 12 inch generate velocities close to the API RP 14E erosion threshold, particularly under compressed operation.

Table 5 quantifies the maximum gas velocity relative to the API RP 14E allowable limit for different trunkline diameters and outlet-pressure conditions. As outlet pressure decreases from 400 to 50 psig, gas density decreases and volumetric flow increases, resulting in progressively higher velocities for a fixed diameter. For the 12-inch trunkline, maximum velocities increase from approximately 19 ft/s at 400 psig to 129 ft/s at 50 psig, corresponding to EVR values rising from 0.32 to 0.82; however, EVR remains below unity for all evaluated cases, indicating compliance with the erosion screening criterion. In contrast, the 10-inch and 8-inch trunklines exceed the allowable velocity at low outlet pressures, with EVR values of 1.15 and 1.76 at 50 psig, respectively, and maximum velocities reaching up to 176 ft/s and 264 ft/s, signaling unacceptable erosion risk. Although the 14-inch trunkline maintains EVR well below unity across all conditions, the marginal reduction in velocity relative to the 12-inch case does not justify the additional capital cost. These results confirm that the 12-inch trunkline provides the optimal balance between erosion control, hydraulic performance, and economic efficiency across early- and mid-life operating conditions.

Material selection implications for sour gas service

The high CO_2 concentration and the presence of H_2S require materials that resist both general corrosion and sulfide stress cracking under sour-service conditions. In this study, the EVR assessment presented in Table 5 evaluates hydraulic performance as a function of pipeline diameter and operating pressure in accordance with API RP 14E and does not depend on material type. Therefore, material selection is assessed separately based on corrosion resistance, mechanical integrity, and compliance with NACE MR0175/ISO 15156. Carbon steel, while commonly used in gas transmission, would require substantial corrosion allowance and stringent operational control in CO_2–H_2S environments, increasing inspection frequency and long-term maintenance risk. In

Table 4. Quantitative impact of booster compression on pipeline sizing

Case	Booster installed	Trunkline diameter (in.)	Inlet pressure (psig)	Outlet pressure (psig)	EVR	Design feasible
A	No	12	>900	50	>1.0	No
B	No	14	~750	50	<1.0	Marginal
C	Yes	12	~650	50	<1.0	Yes
D	Yes	10	>800	50	≈1.0	No

contrast, corrosion-resistant alloys such as duplex stainless steel and austenitic stainless steel provide improved resistance to CO_2-induced corrosion and H_2S-related cracking mechanisms when properly qualified for sour service. From a lifecycle perspective, selecting corrosion-resistant materials reduces reliance on chemical inhibition and mitigates integrity risk, although the higher initial capital cost must be justified through techno-economic evaluation.

Techno-economic implications of design selection

This study evaluates the techno-economic implications of the selected 12-inch trunkline design using cost estimates referenced to 2024 USD, reflecting prevailing market conditions for materials, labor, and energy at the time of analysis. In this study, the cost estimates were developed by the authors using internally prepared engineering data and simulation results, based on a Class 4 (feasibility-level) project definition corresponding to a maturity of approximately 1–15%, consistent with early-stage concept and pre-FEED evaluations (AACEi, 2020; Pamungkas et al., 2024). Deterministic, equipment-factored, and parametric cost methods were applied, with an expected accuracy range of –15% to –30% on the low side and +20% to +50% on the high side. At this level, uncertainty is implicitly captured within the classification accuracy band rather than through explicit probabilistic risk modeling, in accordance with AACEi recommended practice (AACEi, 2020). This structured cost assessment aligns with recent Indonesian techno-economic studies emphasizing the importance of integrating fiscal, engineering, and infrastructure considerations in CO_2-rich development contexts (Ramadhani et al., 2025).

As summarized in Table 6, the estimated CAPEX primarily reflects fixed capital costs associated with pipeline materials, installation, and compression facilities required to maintain delivery pressure under declining reservoir conditions. Direct costs include trunkline and flowline procurement, construction, and compressor installation, while indirect costs cover engineering, project management, and installation support consistent with Engineering, Procurement, Construction, and Installation (EPCI) activities. The selected 12-inch trunkline minimizes oversizing while avoiding excessive recompression, thereby reducing capital intensity compared with larger-diameter alternatives that

Table 5. Maximum gas velocity and API RP 14E allowable velocity across outlet-pressure cases (Trunkline XY).

Outlet press. (psig)	Diameter (inch)	Allowable velocity (ft/second)	EVR	Max velocity (ft/second)	Meets limit?
400	14	60.62	0.26	15.98	No
200	14	85.91	0.37	32.09	No
100	14	117.99	0.51	60.54	No
50	14	156.27	0.68	106.19	No
400	12	60.59	0.32	19.29	No
200	12	86.05	0.45	38.91	No
100	12	117.78	0.62	72.91	No
50	12	156.40	0.82	128.54	No
400	10	59.98	0.45	26.84	No
200	10	84.89	0.63	53.75	No
100	10	116.46	0.87	101.17	No
50	10	153.62	1.15	176.05	Yes
400	8	59.14	0.70	41.13	No
200	8	83.20	0.98	81.40	No
100	8	114.20	1.34	153.35	Yes
50	8	149.92	1.76	264.28	Yes

offer limited hydraulic benefit. At the feasibility level, the CAPEX estimate represents a base cost and does not explicitly separate contingency or management reserve, which should be incorporated during subsequent FEED and detailed design phases as project definition improves (AACEi 2020).

Table 7 presents the estimated OPEX for the selected configuration, including compression energy, routine operation and maintenance, labor, safety management, environmental monitoring, and insurance. These recurring expenditures reflect the operational requirements of transporting CO_2-H_2S-containing gas, including corrosion surveillance, integrity management, and regulatory compliance (Pamungkas et al., 2024). Compression energy constitutes the dominant OPEX component, underscoring the strong coupling between hydraulic design, diameter optimisation, and long-term operating cost. Similar techno-economic interdependencies between infrastructure configuration and lifecycle expenditure have been observed in recent energy infrastructure studies (Supriyadi et al., 2025; Andreasen et al., 2024; Sajan et al., 2024). The OPEX estimate reflects recurring operational costs consistent with a Class 4 feasibility assessment and does not explicitly allocate management reserve for low-probability events, which are typically addressed during later design stages through risk-informed economic evaluation (AACEi 2020).

The detailed breakdown of fuel gas cost is the detailed fuel gas cost breakdown which is shown in Table 8. Fuel consumption was evaluated on a life-of-field basis, where early production stages require minimal compression energy due to higher reservoir pressure, while mid-life operation increases fuel demand as booster compression compensates for pressure decline. The base fuel gas unit cost was derived from Peters and Timmerhaus (1991) and escalated to 2024 values using an indexed natural gas price adjustment. Overall plant cost represents the capital required for facility erection, including equipment procurement, installation, and construction, as summarized in Table 6.

CONCLUSION

This study evaluated an onshore gas trunkline system designed to support the opening of new gas wells producing high-CO_2 gas under declining wellhead pressure conditions. Hydraulic simulations demonstrate that pipeline diameter and inlet pressure control govern both pressure delivery and erosion risk. Among the evaluated options, a 12-in. trunkline consistently maintains the required outlet pressure while keeping the erosion velocity ratio below the API RP 14E threshold across early-life and midlife production scenarios.

Table 6. CAPEX estimation results.

Description		Cost (USD)	Total (USD)
Direct Cost			**199,940,159**
Detailed Engineering		1,380,675	
EPCI for X flowlines & Trunkline from wells to Y field		30,936,963	
Procurement and installation for X compressor		7,797,504	
EPCI for Y flowlines from well to Y station		39,350,043	
EPCI for Y station and CGP modification		35,081,816	
Procurement and installation for Y compressor		22,804,354	
EPCI for Y trunkline to CGP		54,805,161	
CGP modification		7,783,643	
Indirect Cost			**28,491,921**
Company PMT		1,500,000	
Insurances	1.50%	2,999,102	
Tax	12%	23,992,819	
		Total	**228,432,080**

Table 7. OPEX estimation results.

Description	Cost (USD)	Total (USD)	Remark
Raw Material		-	
Utilities		**30,797,744**	
Fuel Gas	29,833,056		for electricity and fuel gas supply
Telecommunication	964,688		radio data service subscription
Operating Labor		**14,313,750**	
Operating	3,600,000		operator 2x4, helper 2x4
Supervision	1,575,000		shift foreman 1x4
Maintenance	3,345,000		lead 1, shift craft men 2x4, helper 1x4, warehouse staff 1x4
Technical services	843,750		engineer 3
Safety	1,800,000		HSE 2x4
Laboratory	1,800,000		lab 8 (HSE 2x4)
Security	1,350,000		security 8 (HSE 2x4)
Labor related costs		**6,011,775**	
Payroll overhead	3,149,025		22% of labour
Supervisory, miscellaneous Labour	1,431,375		10% of labour
Laboratory charges	1,431,375		10% of labour
Capital related costs		**48,351,457**	
Maintenance	11,231,244		5% of plant cost
Operating supplies	2,855,401		1% of plant cost
Environmental	8,566,203		3% of plant cost
Depreciation	14,277,005		5% of plant cost
Local tax and assurances	8,566,203		3% of plant cost
Plant overhead cost	2,855,401		1% of plant cost
Sales related costs		**42,715,512**	
Administration cost	18,984,672		2% of sales
Distribution, and sales expenses	18,984,672		2% of sales
Research and development	4,746,168		0.5% of sales
	Total	**142,190,238**	

Table 8. The detailed breakdown of fuel gas cost.

Year	Main Gas (MMSCFD)	Fuel Cost @1.2 (USD)
2029	35	452,016
2030	35	452,016
2031	35	2,260,080
2032	35	2,260,080
2033	35	2,260,080
2034	30	2,260,080
2035	30	2,260,080
2036	30	2,260,080
2037	30	4,520,160
2038	25	4,520,160
2039	10	1,808,064
2040	7	1,808,064
2041	5	904,032
2042	4	904,032
2043	3	904,032

The integration of inlet booster compression proves essential for sustaining gas delivery during pressure decline. The booster restores hydraulic margin without requiring pipeline oversizing, thereby preserving operational flexibility and maintaining safe gas velocities. This combined sizing and compression strategy strikes a good balance between the needs for hydraulic performance and integrity when moving sour gas.

Material evaluation confirms that corrosion-resistant alloys, specifically duplex stainless steel and austenitic stainless steel, provide the necessary resistance to CO_2 corrosion and H_2S-related cracking under the modeled operating conditions. Their application reduces integrity risk and operational dependence on corrosion mitigation measures compared to carbon steel alternatives.

The techno-economic analysis shows that the chosen configuration strikes a good balance between capital and operating costs by cutting down on superfluous pipe oversizing and too much compression demand. In general, the results show that combining hydraulic, material, and economic design makes for a technically sound and financially viable foundation for building inland gas trunkline systems that move gas streams that are high in CO_2 and H_2S.

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GLOSSARY OF TERMS & SYMBOLS

Terms & Symbols	Definition	Unit
AACEi	American Association of Cost Engineers International	
API	American Petroleum Institute	
API 5L	American Petroleum Institute Specification 5L	
API RP 14E	American Petroleum Institute Recommended Practice 14E	
ASME	American Society of Mechanical Engineers	
CAPEX	Capital Expenditure	USD
CGP	Central Gas Plant	
CO_2	Carbon dioxide	
EPCI	Engineering, Procurement, Construction, and Installation	
EVR	Erosional Velocity Ratio	
FEED	Front End Engineering and Design	
H_2S	Hydrogen Sulphide	
ISO	International Organization for Standardization	
MMSCFD	Million Standard Cubic Feet per Day	
MR	Material Requirement	
NACE	National Association of Corrosion Engineers	
OPEX	Operating Expenditure	USD
PMT	Payment	
Pre-FEED	Preliminary-Front End Engineering and Design	
ρ_m	Mixture density	lb/ft^3
C	$C = 100$, empirical constant	$(ft/s \cdot \sqrt{lb/ft^3})$
V_e	Maximum allowable velocity	ft/s

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