Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) Intermodal Transport Hubs

FINAL PROJECT REPORT

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Final Project Report

1.0 Introduction and Background

Carbon dioxide (CO_2) transport will be required to implement carbon capture utilization storage (CCUS) in instances where a CO_2 source does not overlie a viable storage target or generates a volume of CO_2 that requires more than one well to store. Most studies have looked at pipeline transport of CO_2, as this is the most economical mode for large volume transport and is traditionally considered the most viable option (Onyebuchi et al., 2018; Lu et al., 2020). CO_2 pipeline opposition like the recently mothballed Navigator Pipeline (Dura, 2023) and high-profile accidents like the Satartia, Mississippi pipeline rupture (Kieba et al., 2023), however, means that other modes of transport, such as barge, rail, and truck, may be more viable alternatives for smaller sources. Pipelines also require a larger investment in capital and time, as they often require extensive planning, environmental assessments, and public engagement (Schoots et al., 2011).

Intermodal and/or non-pipeline transport of CO_2 has been previously studied by some peer reviewed literature, although it is not as commonly studied as pipeline transport. Many of the intermodal transport studies focused on pipeline and shipping transport, often for offshore CCUS projects (Kjarstad et al., 2016; Munkejord et al., 2016; Orchard et al., 2021; Roussanaly et al., 2013a, 2013b, 2013c, 2014). Others discuss pipeline, trucking, and/or rail (Carbon Sequestration Leadership Forum [CSLF], 2021; Lu et al., 2020; Han et al., 2015; Simonsen et al., 2024; Mallon et al., 2013; Bergqvist and Monios, 2021; Bielenia et al., 2023; Zhang et al., 2013; Dehdari et al., 2023; Svensson et al., 2004), which are the transport mechanisms considered in this study. Several studies that have considered pipeline transport (Knoope et al., 2013; Onyebuchi et al., 2018; Hasan et al., 2014; Jensen et al., 2013; Grant et al., 2018; Middleton et al., 2012; Morbee et al., 2011; Brunsvold et al., 2011; Peleteri et al., 2018).

One of the most important considerations when developing a transport network is costs. Because CO_2 capture costs are high for many sources, viable transport and storage networks must be efficient to ensure an economically viable carbon mitigation system. The per tonne cost of transport limits the use of trucks and rail for CO_2 transport projects (CSFL, 2021). Svensson et al. (2004) went so far as to say that only pipeline, barge, or a combination of the two modes provide a viable pathway from an economic standpoint. However, other factors may lead to the selection of other modes of transport. Rail transport can be accomplished largely using existing infrastructure. This conclusion led Roussanaly et al. (2017) to conclude that, under circumstances where additional CO_2 processing costs to transport via train are minimal and where risk tolerance is low, rail transport may be the preferable mode. An additional drawback to the use of rail is that the source and sink must be located near a railway (Lu et al., 2020). This is not practical in all areas but is less of a problem in an industrialized area like the study region discussed this in this report. Trucks also do not require special investments and may be the preferred mode to move smaller volumes of CO_2 shorter distances. Han et al. (2015), for instance, mention that tanker trucks may be most viable during the early stages of a project prior to the large-scale implementation and prior to a pipeline being built. While trucking is adaptable, the overall costs are high due to fuel and labor (Lu et al., 2020).

Several studies have discussed the economics of CO_2 pipelines. Knoope et al. (2013) studied 14 cost models to determine the efficacy of the models to estimate costs of CO_2 pipelines. The authors note that costs are dependent on mass flow; pipeline length, diameter, and thickness; elevation change; terrain;

impurities; and technology and material costs, which can lead to a large range of costs (Knoope et al., 2013). The authors state that the cost models underestimate CO_2 pipeline costs because they are based on the cost of natural gas pipeline construction in the United States in the 1990s and early 2000s. Additionally, except for weight-based models, these models do not account for the higher operation pressure of CO_2 pipelines and likely higher material costs that occurred over time. Fewer studies have modeled the cost of transport using truck and rail; however, a recent paper by Myers et al. (2024) presents a model for these modes that was used in this study.

Onyebuchi et al. (2018) note that the most important issues facing CO_2 pipeline construction include pipeline integrity, CO_2 availability; costs, and environmental, health, and safety (ES&H) issues. The authors provide a review of available literature to determine the state of knowledge to overcome these issues. Some of the most important findings from their review are related to the impact of impurities and corrosion management. The authors noted the need for careful consideration of CO_2 stream impurities, particularly as multiple streams of CO_2 must be managed in pipeline networks, such as the one being investigated as part of this project. The authors also note the impact of elevation changes and impurities on pressure drop in the line potentially impacting the spacing of pressure booster stations along the line.

The carbon footprint of different transport modes is also an important consideration because greenhouse gas emissions during transport could impact the efficacy of the carbon mitigation project. Several factors influence the lifecycle emissions of intermodal transport, including the type of fuel, age of vehicles, technological advancements of the vehicles, route selection, driving conditions, and logistics (e.g., load fact) (Bielenia et al., 2023; Dehdari et al., 2023). As such, a complex intermodal transport network may need to use multiple different emissions factors to accurately calculate lifecycle emissions.

Studies have discussed modeling intermodal transport and pipeline routing optimization (Zhang et al., 2013; Middleton et al., 2009; Morbee et al., 2011). Zhang et al. (2013) present an intermodal CO_2 transport model that minimizes costs of intermodal transport networks and shows how it can be used to limit CO_2 emissions under different assumed CO_2 costs. Software like the Scalable Infrastructure Model for Carbon Capture Storage (SimCCS), described by Middleton et al. (2009), can help design these optimized routes by providing a robust modeling approach that generates viable, optimized pipeline network based on terrain and other factors that complicate pipeline routes (e.g., environmentally and culturally sensitive areas, critical infrastructure, populated areas, and other obstacles). Similarly, Morbee et al. (2011) describe a model capable of optimizing pipeline routing between multiple sources and sinks across different areas.

Pipeline optimization may improve economics through the optimization of pipeline routes with one or more trunk lines and a series of branches connecting several sources to one or more storage areas (Hasan et al., 2014; Jensen et al., 2013; Grant et al., 2018; Middleton et al., 2012; Morbee et al., 2011). Previous work has shown the potential benefits of this approach through regional (Grant et al., 2018; Jensen et al., 2013; Middleton et al., 2012) and continental (Hasan et al., 2014; Morbee et al., 2011) optimized pipeline networks. The pipeline itself can also help optimize project economics by providing mitigations for project uncertainties or improving efficiencies. Wetenhall et al. (2017) discuss the potential for improving efficiencies by using pipelines as temporary storage vessels for CO_2 to help mitigate storage uncertainties.

Other issues may reduce the overall operational efficiency of pipelines. Two papers note that pipeline designs often do not consider impact of impurities on pipeline performance (Peletiri et al., 2018; Lu et al., 2020). Peletiri et al. (2018) reviewed several aspects of pipeline development and operations that could be impacted by the presence of impurities. They found that improved knowledge of the impact of impurities on density and viscosity of the fluid will help optimize pipeline velocity and operating conditions. Impurities in the CO_2 stream may also complicate optimization of CO_2 transport networks; however, establishing CO_2 quality standards must be weighed against the economics of separating CO_2 from other constituents, which have different costs for different CO_2 source types (Simonsen et al., 2024).

The CO_2 pipeline industry has a wealth of experience that dates back decades. Best practices for pipeline design and operation have been developed by US institutions like the American Petroleum Institute (API) as well as international organizations like Det Norske Veritas (DNV). Johnsen et al. (2011) report on the DNV (2010) recommended practice, which they state is applicable to onshore and offshore pipelines and intended to supplement the international, national, state, and local regulations governing the pipelines. In addition, API is currently developing a recommended practice for CO_2 transport by pipeline (RP 11CO_2), which has been drafted but is currently awaiting final approval. Piazza (2024) reports that this standard will address issues related to integrity, impurities, and risks. The guidance will also deal with potential accidents, including causes, consequences, mitigations, and recovery mechanisms for these accidents. Finally, the guidance will address construction and siting requirements. Both DNV and API have recommended practices for pipelines that, in conjunction with national, state, and local regulations, may help guide the construction of CO_2 pipelines.

The selected study area for the project is the tristate region of Ohio, Pennsylvania, and West Virginia. This is an important economic region with many different sources of CO_2, ranging from industrial facilities like natural gas processing plants, chemical production plants, and steel plants, as well as fossil fuel electric power facilities (United States Environmental Protection Agency [U.S. EPA], 2024). The goal of the project is to develop the pre-Front End Engineering Design (pre-FEED) study of an intermodal transport hub that demonstrates an efficient and economic transport network to transport CO_2, using multimodal methods, from sources of CO_2 to sinks of CO_2 in this tristate region. The project considered the existing regional infrastructure of roads, rail and river transportation methods along with construction of new infrastructure. The project will also take into consideration the decarbonization incentives and carbon credit policies. The project will coordinate with the Appalachian Regional Clean Hydrogen (ARCH2) Hub Project, also led by Battelle, and include information about other publicly announced projects to ensure the impact aligns with other federal investments. Two top-line objectives defined project success. The first is to develop a conceptual design and a pre-FEED design. The second is to integrate costs, regulations, permitting and decarbonization incentives, and policies into the economics of the project.

This report provides an assessment of the pre-FEED concept and design. The report discusses the following:

- Section 2 discusses developing the intermodal transport network from conceptual design and optimization, design basis, and regional connections to other projects to ensure that the project is appropriately sized and has a realistic scope.
- Section 3 discusses the permitting and regulatory plan and land acquisition plan to ensure that the project can be permitted and that the land and rights-of-way (ROWs) can be obtained.
- Section 4 discusses the project cost estimate and business case analysis (BCA) to ensure the project is economically viable.
- Section 5 discusses risks, including hazard identification (HAZID) and the environmental safety and health (ES&H) assessment to ensure that risks are properly quantified and prioritized.
- Section 6 provides the pre-FEED study for the selected node of the project hub.
- Section 7 discusses the project accomplishments and path forward to progress the project to a full FEED assessment.

2.0 Developing Intermodal Transport

The *Developing Intermodal Transport* task had four subtasks. The first was to develop *conceptual designs* that ensured that the intermodal hub is based on realistic source conditions and considered realistic transport options. The second subtask sought to establish *design and optimize the intermodal transport hub*. This involved aligning the sources in logical groups or clusters and developing pooling strategies to ensure that the proper transport modes are selected and that the system is optimized. In addition, a single node was selected for the pre-FEED analysis. The *basis of design* was then completed for the selected pre-FEED node. Finally, the *regional connection* considered how the hub could be expanded and connected to other projects in the area.

2.1 Conceptual Design

The Conceptual Design subtask included four goals: (1) identify source sponsors and sink sites, (2) estimate of appropriate transport modes and distances, (3) develop multiple realizations of parameters applicable to multi-modal transport and down-select set of designs are expected to be advanced to the pre-FEED stage, and (4) identify specific site (i.e., a single node) that will serve as the site for subsequent detailed analyses.

Goal 1. Identify source sponsors and sink sites

Sources sponsors and CO_2 emissions were identified during the proposal using publicly available data from the U.S. Environmental Protection Agency (U.S. EPA) Greenhouse Gas Reporting Program (GHGRP) (U.S. EPA, 2024). This reference provided source locations and 2023 annual CO_2 emissions. Because these partners do not have immediate plans to capture CO_2 at their plants, the sources were anonymized (Table 1).

Table 1. Anonymized sources for both scenarios considered in the project.

No.	Facility Name	Elevation (ft above mean sea level [amsl])	County	State	Source Type	Capturable CO_2 Emissions (million tonnes per year [MMt/yr])
Existing Anonymized Sources in the First System						
1	NG Compressor A	1031	Washington	PA	NG Compressor	0.04
3	NG Compressor B	1217	Monongalia	WV	NG Compressor	0.03
4	NG Gathering and Boosting A	1132	Allegheny	PA	NG Gathering/Boosting	0.225
5	NG Gathering and Boosting B	732	Allegheny	PA	NG Gathering/Boosting	0.775
6	NG Compressor C	1229	Monroe	OH	NG Compressor	0.07
7	NG Compressor D	1280	Wetzel	WV	NG Compressor	0.04
8	NG Compressor E	1125	Greene	PA	NG Compressor	0.05
9	NG Gathering and Boosting C	978	Washington	PA	NG Gathering/Boosting	0.325
10	NG Compressor F	1005	Washington	PA	NG Compressor	0.075
11	NG Compressor G	971	Monongalia	WV	NG Compressor	0.04
RR1	Railyard 1	1156	Washington	PA	Railyard/Rally Point	0
RR2	Railyard 2	820	Monongalia	WV	Railyard	0
RR3	Railyard 3	696	Wetzel	WV	Railyard	0
ST	Storage	1065	Tuscarawas	OH	Storage Area	0
-	**Scenario 1 Total**	**-**	**-**	**-**	**-**	**1.67**
Hydrogen Plant included in the Second System						
2	Hydrogen Production Facility	648	Doddridge	WV	Hydrogen	0.5
PLM	Pipeline B Meeting Point	1231	Wetzel	WV	Rally Point	0
-	**Scenario 2 Total**	**-**	**-**	**-**	**-**	**2.17**

Potential storage sites were identified by plotting the US Department of Energy (DOE)-sponsored studies in the area (Battelle, 2024; Cumming et al., 2019; Gupta et al., 2014) as well as the projects that have been recently announced by commercial projects (Tenaska, 2024a, b, c). Figure 1 maps out these potential storage sites in relation to sources (Table 1) in the region. Details about the storage sites that were considered are provided in Table 2.

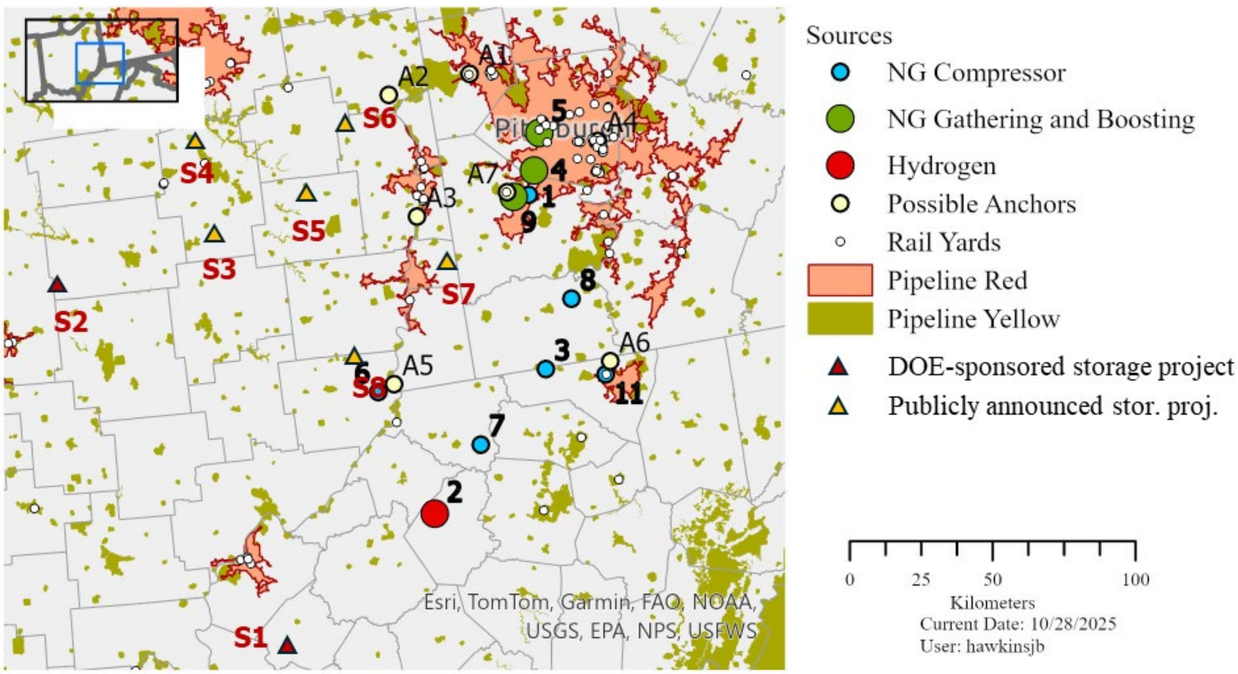

*Figure 1. Map of anonymized sources (#), potential storage sites (**S#**), and anonymized anchor sites (A#). Also shown are areas where pipeline development may be complicated by high populated aeras (pipeline red) or other sensitive areas, including other populated areas, sensitive areas, and protected lands (pipeline yellow).*

Table 2. Storage sites and capacity estimates for sites considered in the project. Numbers correspond to those on the map in Figure 1.

No.	Storage Site Descriptor	Storage Type	County, State	Elevation (ft amsl)	Capacity[b] (MMt/yr)
S1	Ritchie, WV MRCI Model (Oriskany)	Saline	Ritchie, WV	1,034	Subcomm.
S2	CAB-CS Secondary (Cambro-Ord/Clinton)	Saline/EOR	Tuscarawas, OH	1,036	Comm.
S3	Harrison County, OH	Saline	Harrison, OH	985[a]	Unk.
S4	Carroll County, OH	Saline	Caroll, OH	1,249[a]	Unk.
S5	Jefferson County, OH	Saline	Jefferson, OH	1,051[a]	Unk.
S6	Hancock County, WV	Saline	Hancock, WV	1,087[a]	Unk.
S7	Washington County, PA	Saline	Washington, PA	1,212[a]	Unk.
S8	Marshall County, WV	Saline	Marshall, WV	1,164[a]	Unk.
NA	Mountaineer (Cambro-Ord)	Saline	Mason, WV	590	Comm.
NA	CAB-CS Primary (Cambro-Ord/Clinton)	Saline/EOR	Coshocton, OH	773	Comm.

Notes: a. Exact project location unknown. Elevation is from middle of county. b. Capacity are either unknown (unk.), commercially viable quantities (comm.) (i.e., 1.67 MMt/yr or more), or subcommercial quantities (i.e., less than 1.0 MMt/yr).

Goal 2. Estimate of appropriate transport modes and distances

Transport modes and distance were initially assessed through a mapping exercise during which the sources were logically clustered, different modes were considered, and distances of transport were estimated. This involved clustering nearby sources, selecting logical transport modes, and making rough estimates of the distances between the selected sources and a selected sink. This work was conducted using a commercial mapping software and data from the Department of Transportation (United States Census Bureau, 2023; Federal Railroad Administration [FRA], 1995) and the Pipeline and Hazardous Materials Safety Administration (PHMSA, 2019) as seen in Figure 2 below.

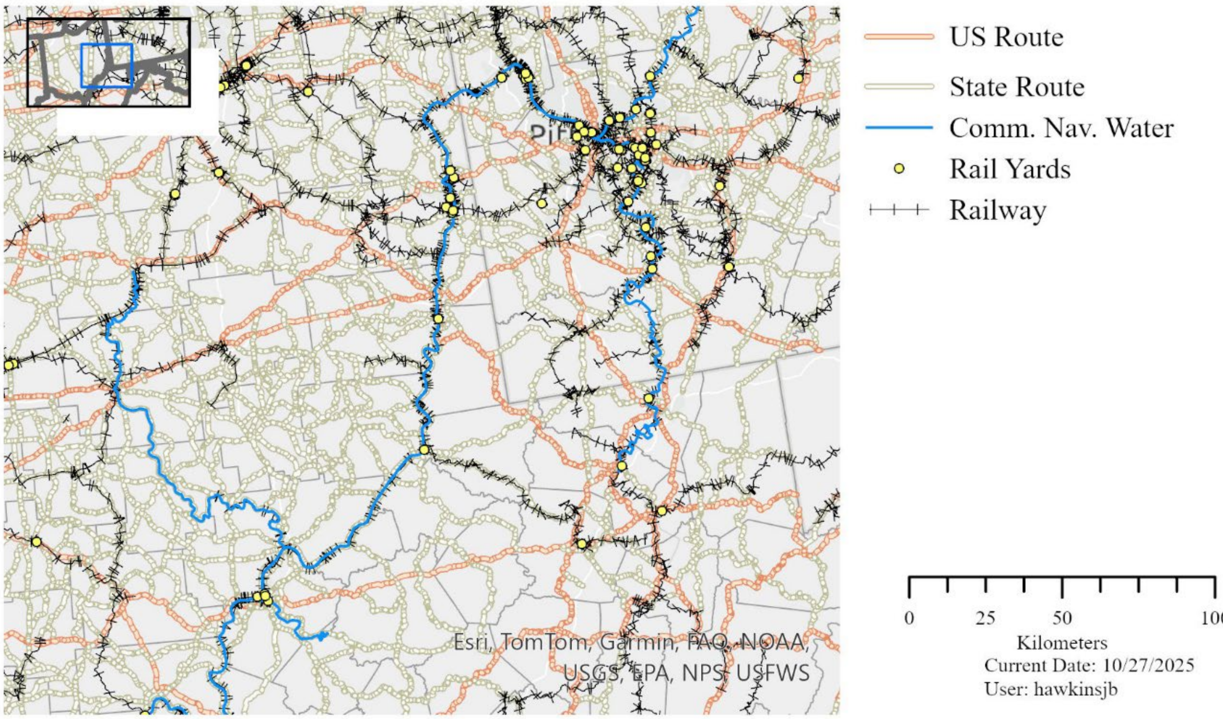

Figure 2. Modes of transport in the study area. Shapefiles are from Department of Transportation (United States Census Bureau, 2023; FRA, 1995) and the PHMSA (2019).

Once sources clusters were established, multi-modal interconnections for the hub were defined using a logical decision tree process that balanced the distance between nodes, the volume of CO_2, the proximity of railyards, and the feasibility of pipeline construction. These decision trees, along with the rationale for decision points, are presented in Figure 3, Figure 4, and Figure 5 for pipelines that are less than 25 miles from the next node, 25 to 75 miles from the next node, and more than 75 miles from the next node, respectively.

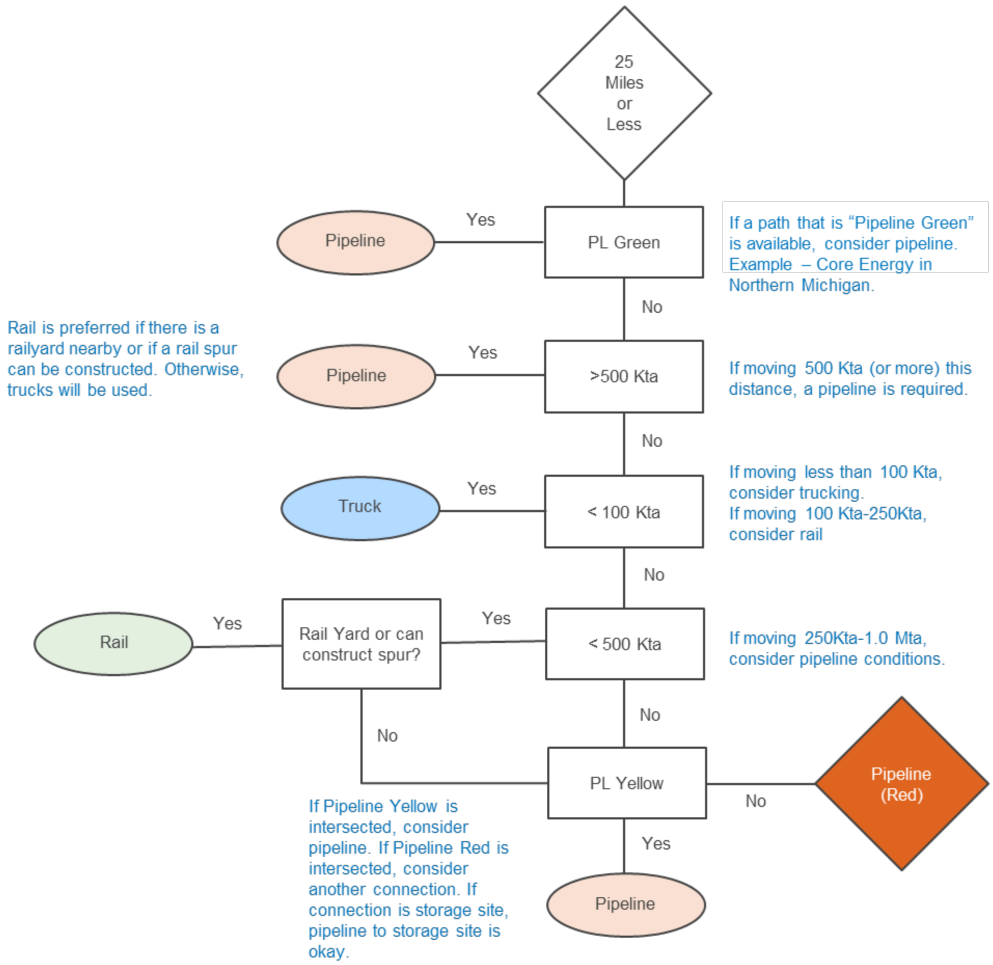

Figure 3. Decision tree for mode selection (less than 25 miles from node to node). Rationale for decision points are presented in blue text.

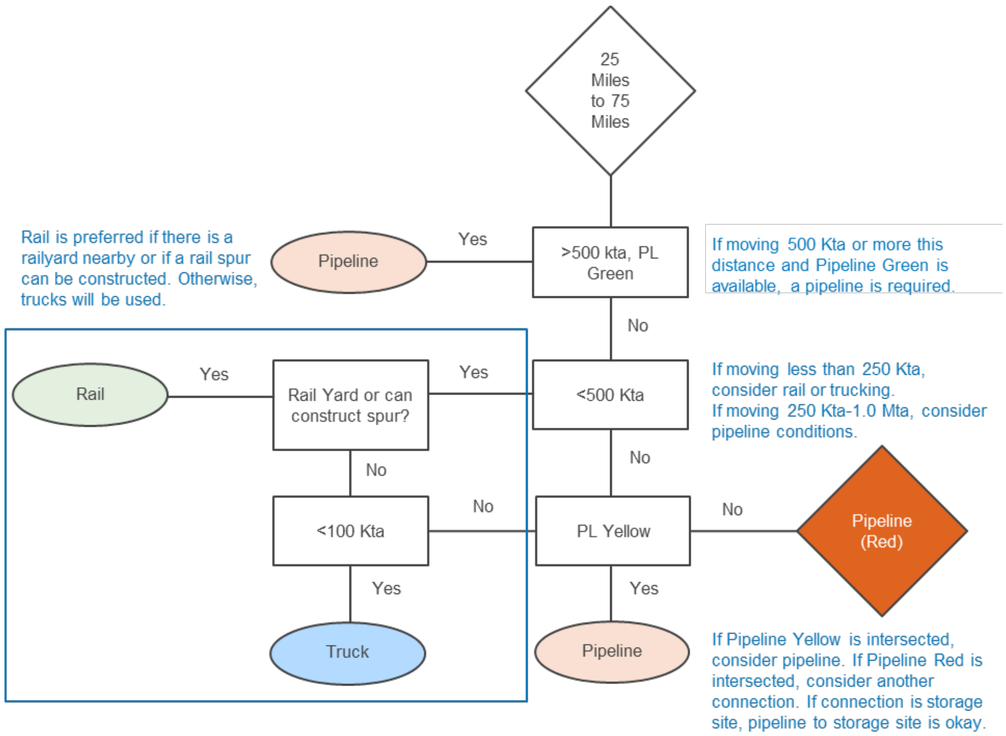

Figure 4. Decision tree for mode selection (25 to 75 miles from node to node). Rationale for decision points are presented in blue text.

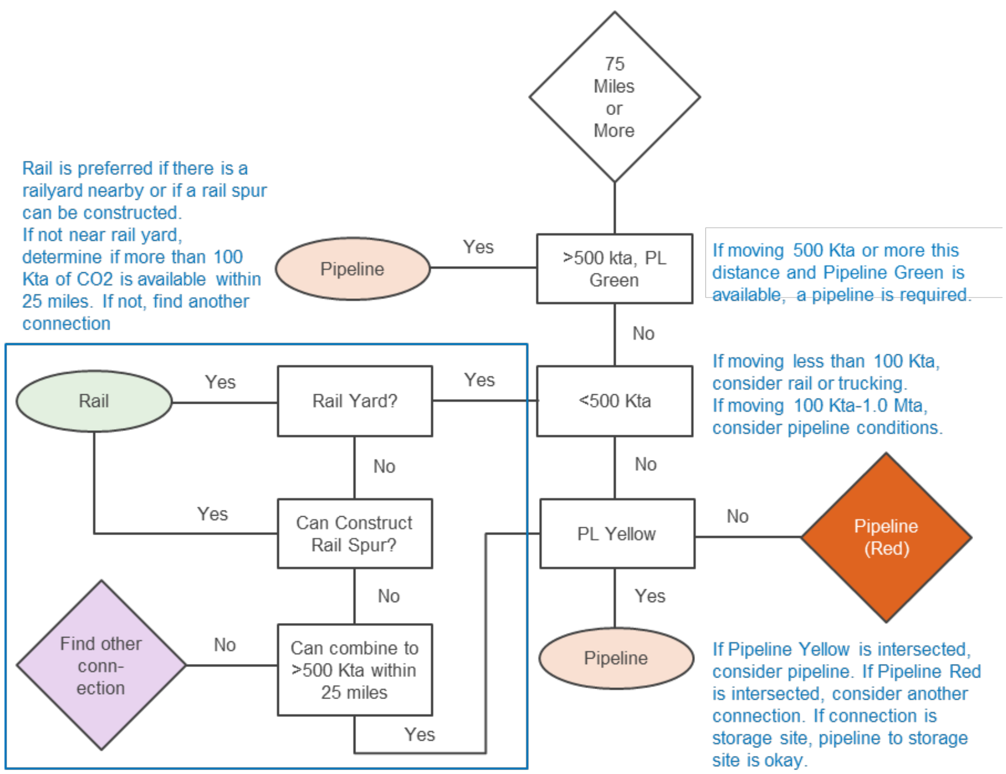

Figure 5. Decision tree for mode selection (more than 75 miles from node to node). Rationale for decision points are presented in blue text.

Goal 3. Develop multiple realizations of parameters applicable to multi-modal transport and down-select set of designs are expected to be advanced to the pre-FEED stage.

Two individual setups were developed to connect the sources (Figure 6). Setup A connected the sources in the northern portion of the study area and connected them Storage Area S2 in eastern Ohio. Setup B considered the sources in the Pittsburgh area These setups were combined to develop a combined scenario that served as Scenario 1. The project team then considered the construction of a hydrogen facility to determine how a newly built facility would impact the network. This is considered Scenario 2. These are discussed in detail below.

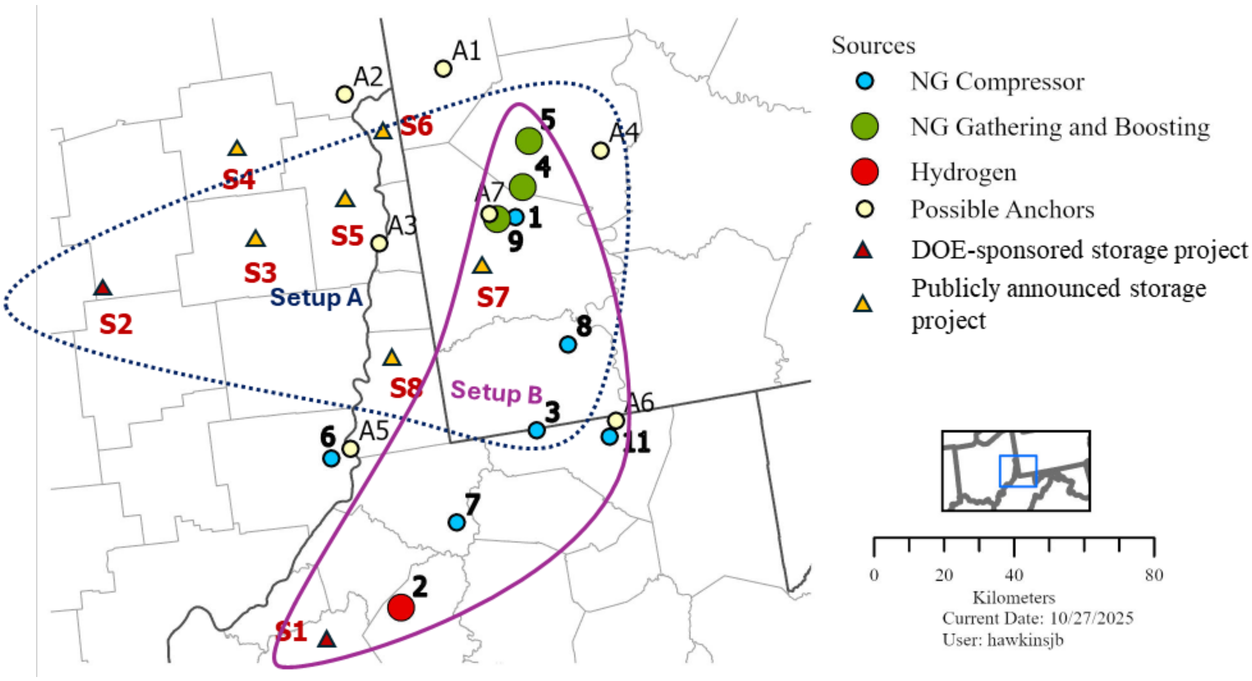

Figure 6. Map showing the initial setups that were combined and modified to develop the sources and sinks used in Scenarios 1 and 2.

Goal 4. Identify specific site (i.e., a single node) that will serve as the site for subsequent detailed analyses

The project team also sought to determine and anchor site for the project. This site would provide a point at which the transport hub could be organized and serve as the point from which all the CO_2 could be routed. As such, the anchor site would serve as a single node within the preferred scenario was selected for subsequent detailed analyses. Seven different anchor sites were considered and are listed in Table 3. Factors considered in the selection included the proximity to partner sources and railyards, which were considered the transport points that would be hardest to build. Six of the seven sites were large sources in the area, including one steel plant (A1), two chemical plants (A2 and A3), and three electric power plants (A4, A5, and A6). The last anchor point (A7), and the selected node, is the Railyard 1 Hub Receiving Area (RY1 Hub Area). The node was selected to ensure that all applicable transport mechanisms are accounted for and that all states are considered. Subsequent analyses like parts of the design basis (see Subtask 2.3), regulations and permitting (Task 3), the BCA (Subtask 4.2), and environmental safety and health analysis (Task 5) are completed considering this node. For issues related to design and optimization (Subtask 2.2), parts of the design basis (see Subtask 2.3), regional connecting (Subtask 2.4), project cost analysis (Subtask 4.1), and long lead material and equipment needs (Subtask 4.3), the entire preferred scenario was considered.

Table 3. Potential anchor sites considered in the project. Numbers correspond to those presented in Figure 1.

No.	CO_2 Emissions (MMt)	Industry	Within 10 Miles of Partner Source	Within 25 Miles of Partner Source	Within 1 mile of Rail Yard	Within 10 miles of Rail Yard
A1	3.0	Steel Plant	Yes	Yes	Yes	Yes
A2	1.4	Chemical Plant #1	No	Yes	Yes	Yes
A3	0.52	Chemical Plant #2	Yes	Yes	No	Yes
A4	3.9	Power Plant #1	No	Yes	No	Yes
A5	10.0	Power Plant #2	No	Yes	No	Yes
A6	3.0	Power Plant #3	No	No	No	No
A7	NA	Railyard 1	Yes	Yes	Yes	Yes

2.2 Intermodal Transport Design and Optimization

The intermodal transport design and optimization included two goals: (1) investigating the methods of transport most appropriate for selected sources and (2) detail engineering infrastructure. Two systems are discussed. The first gathers CO_2 from hypothetical locations of sources that currently exist in the study area, focusing on small and medium-sized sources throughout southwestern Pennsylvania, northern West Virginia, and eastern Ohio (Figure 7; Table 1). The second scenario explores how the network would change with the introduction of a hydrogen plant in Doddridge County, WV (Figure 8; Table 1). CO_2 emissions shown are capturable CO_2 emissions.

Scenario 1 Pipeline Interconnections: The pipeline for Scenario 1 runs from Pittsburgh to the RY1 Hub Area (Figure 7). It connects four different sources of CO_2 to the Hub:

1. The pipeline originates at the Gathering and Boosting Station B in Pittsburgh and connects to the Gathering and Boosting Station A.
2. The pipeline then connects from the Gathering and Boosting Station A to the Gathering and Boosting Station C and co-located Compressor F.
3. The pipeline connects from the Gathering and Boosting Station C and co-located Compressor F to the RY1 Hub Area where it picks up additional CO_2 from the remaining sources considered in the scenario.
4. The pipeline routes from the RY1 Hub Area to the Storage Area in Tuscarawas County, Ohio.

Scenario 1 Truck Transport: Trucking of CO_2 will be accomplished using tanker trucks capable of carrying 20 tonnes of liquefied CO_2 per load (Myers et al., 2024). To minimize disruptions to local traffic patterns, the routes will be restricted to highways (e.g., interstates, state highways, etc.) except when leaving the point of capture or approaching the destination (if facilities are not adjacent to highways). Five distinct trucking routes are planned for Scenario 1:

1. Natural Gas Compressor B to Railyard 2 – One truck approximately every 5 hours traveling 18.0 miles to Railyard 2 for Train transport tox RY1 Hub Area.
2. Natural Gas Compressor D to Railyard 2 – One truck approximately every 4 hours traveling 72.9 miles to Railyard 2 for Train transport to RY1 Hub Area.
3. Natural Gas Compressor E to Railyard 2 – One truck approximately every 3 hours traveling 26.6 miles to Railyard 2 for Train transport to RY1 Hub Area.
4. Natural Gas Compressor C to Railyard 3 – One truck approximately every 3 hours traveling 26.6 miles to Railyard 2 for Train transport to RY1 Hub Area.

Scenario 1 Rail Transport: Rail transport is accomplished using unit trains of rail tankers. Each rail tanker is assumed to hold 80 tonnes (Myers et al., 2024) and each intermodal car is assumed to hold 20 tonnes. For Scenario 1, two railyards receive CO_2 and transport it to the RY1 Hub Area:

1. Railyard 2 (and co-located Natural Gas Compressor G) to RY1 Hub Area. Around 6400 tonnes are delivered 139.2 miles from Railyard 2 to the RY1 Hub Area every 16-17 days by a tanker unit train.
2. Railyard 3 to RY1 Hub Area. Around 1700 tonnes are delivered 85.8 miles from Railyard 3 to the RY1 Hub Area every seven to eight days.

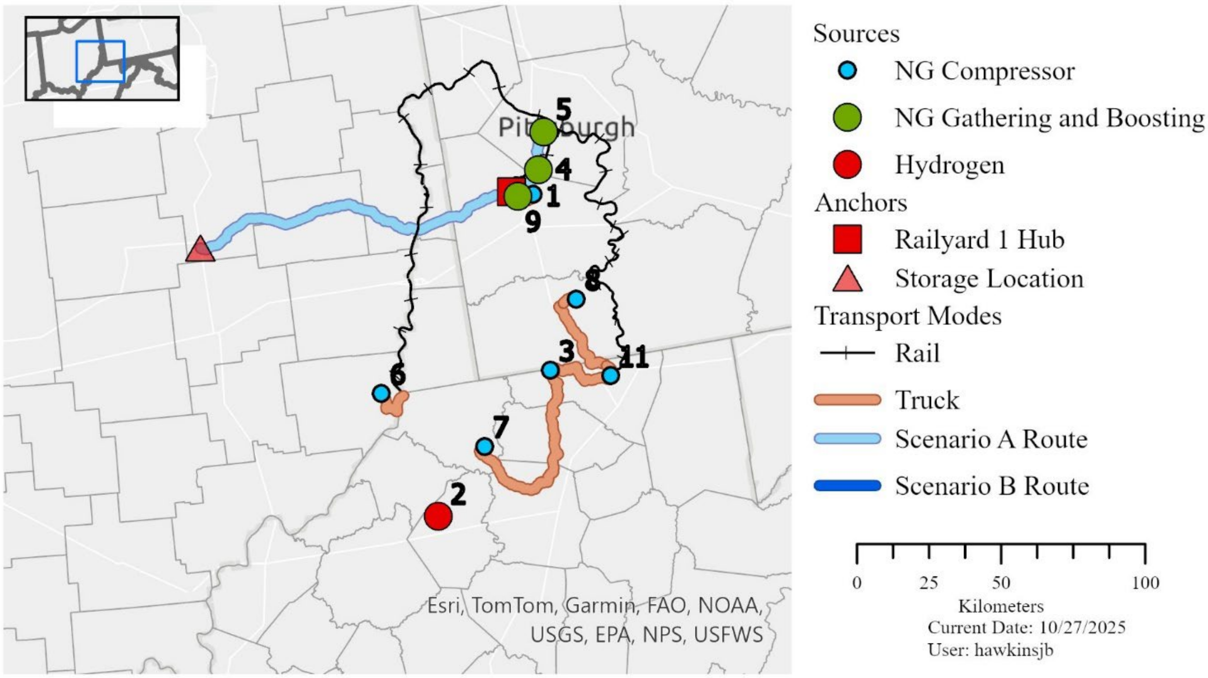

Figure 7. Scenario 1: intermodal transport for existing anonymized sources. Roads and railroads are determined using data from the US Census Bureau (2023) and FRA (1995).

Scenario 2 considers the impact of a newly constructed hydrogen plant on the intermodal transport hub (Figure 8). The plant is in Doddridge County, West Virginia, and emits 500,000 tonnes of CO_2 per year. The CO_2 is transported via pipeline northward to RY1 Hub Area. The location of the pipeline impacts the transport of CO_2 from Natural Gas Compressors C and D. The changes resulting from this scenario are detailed in bold text below:

- NG Compressor A: No change from initial plan
- NG Compressor B: No change from initial plan
- NG Gathering and Boosting A: No change from initial plan
- NG Gathering and Boosting B: No change from initial plan
- **NG Compressor C: 70,000 tonnes per year meeting pipeline in Wetzel County, West Virginia**
- **NG Compressor D: 40,000 tonnes per year transported to hydrogen plant by pipeline**
- NG Compressor E: No change from initial plan
- NG Gathering and Boosting C: No change from initial plan
- NG Compressor F: No change from initial plan
- NG Compressor G: No change from initial plan
- **Railyard 2: 40,000 tonnes per year less CO_2 transported (new amount: 110,000 tonnes per year)**
- **Railyard 3: No longer used**
- **RY1 Hub Area: 500,000 tonnes per year additional CO_2 transported**

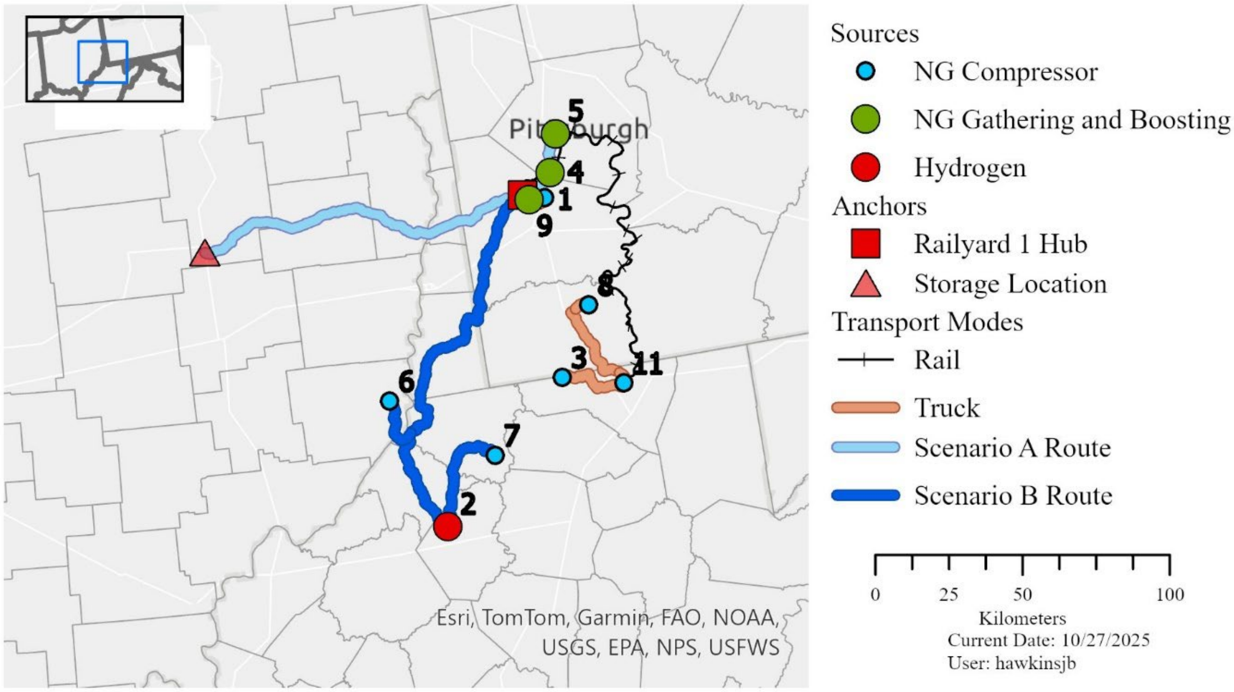

Figure 8. Scenario 2: intermodal transport for existing anonymized sources and a newly built hydrogen plant. Roads and railroads are determined using data from the FRA (1995) and the United States Census Bureau (2023).

For both systems, all CO_2 must meet the pipeline specifications shown in Table 4 prior to arriving at the RY1 Hub Area.

Table 4. Gas specifications for both conceptual scenarios. Gas must meet these specifications prior to entering the RY1 Hub Area.

Component	Limit	Reason
CO_2	>95 mol%[1,2]	Line efficiency, compression
Water	<50 ppmv[1]	Corrosion
Oxygen (O_2)	<10 ppmv[2]	Corrosion
Nitrogen (N_2)	<1 mol%[2]	Line efficiency, compression
Hydrogen (H_2)	<10 ppmv[1]	Line efficiency, compression
Hydrogen Sulfide (H_2S)	<10 ppmv[1]	Health risks, acid formation
Total Sulfur	<35 ppmv[1]	Foul odor, acid formation
Carbon Monoxide (CO)	<35 ppmv[2]	Health risks
Glycol	46 ppbv[2]	Damage to pump seals
Ammonia (NH_3)	<50 ppmv[2]	Health risks, corrosion
Argon (Ar)	<1 mol%[2]	Line efficiency, compression
Particulates	<1 ppmv[2]	Clogging, damage

2.3 Design Basis

The purpose of the design basis was to describe the RY1 Hub Area that will serve as the rally point for CO_2 in both scenarios. The facility will be capable of receiving and distributing at least 1.67 million metric tonnes (t) of pipeline grade CO_2 per year for Scenario 1 and at least 2.17 million metric tonnes of CO_2 per for Scenario 2. Assumptions are presented in this section while the remaining items of the pre-FEED are presented in Section 6.

The system is designed from the perspective of a CO_2 transport entity (Figure 9). The transport operator is assumed to be a mid-stream CO_2 pipeline company that is operating near RY1 Hub Area. The transport operator is purchasing the CO_2 from all sources and selling it to the storage operator for use in a saline storage project in Tuscarawas County, Ohio. This assumes that purification of CO_2 to the specifications required for CO_2 transport and initial compression of CO_2 is handled outside of the examined system. Liquefaction and intermediate storage for trucking and rail and compression to pipeline specifications for pipeline transport are considered within the integrated project design. Executing transport and interconnections between transport modes are also considered to be the purview of the transport operator. Once the CO_2 is transported to the storage location, the storage operator is assumed to be responsible for offloading the CO_2, providing intermediate storage, and eventual recompression and injection of the CO_2.

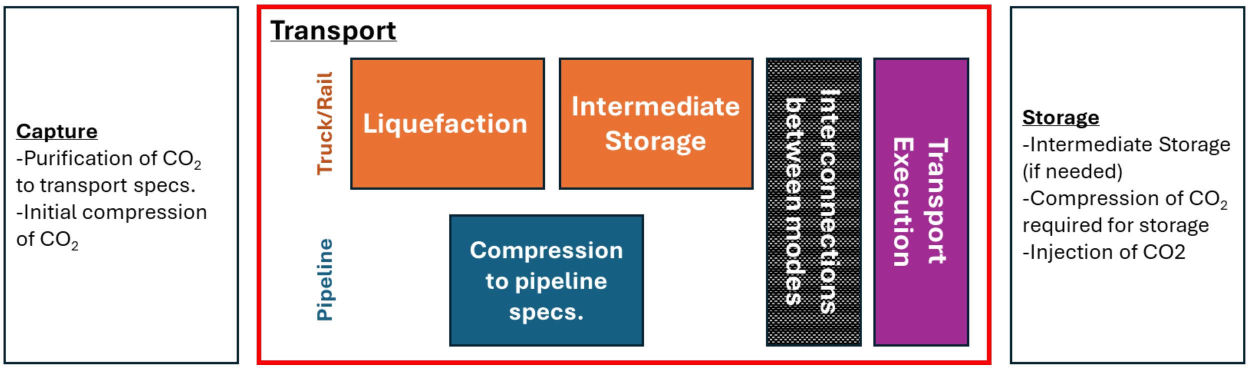

Figure 9. Integrated project considerations. This project considers liquefaction and intermediate storage for rail and trucking, interconnections between modes, and transport execution.

The transport operator is assumed to be in control of all aspects of pipeline and trucking but to be paying a fee for transport via rail. Additional assumptions are provided below:

- The capture systems are assumed to always operate, except during scheduled downtimes. The downtimes are assumed to occur once a year and equal to about seven (7) days, or around 2% of the entire year. These downtimes are assigned randomly and meant to demonstrate scheduled maintenance of the capture systems.
- Trucks are assumed to operate for a single 8-hour shift each day (including weekends). Therefore, storage is required at each source served by a truck for the CO_2 two-thirds of the time.
- Trains are assumed to run as unit trains of 80 cars for both tankers and intermodal transport containers. Additional equipment required at the railyard to move and store CO_2 are considered in this analysis. In addition, the analysis also considers acquisition of all required equipment for the project, including rail tankers and intermodal cars, storage tanks, and required pumps and connections. However, improvements to rail system (e.g., expansion of the track or land, increased employment of railyard workers, or increased capacity to serve cars) are not considered. The analysis assumes there is capacity at the railyard to service all train cars needed for the project. For the economic assessment, the project assumes a single payer is paying a negotiated rate to the railyard to service all unit trains and host storage tanks.
- The pipeline(s) will operate continuously. Required maintenance is expected to be completed in isolated sections to minimize impacts on operations. The pipeline(s) will be developed according to API5L PSL2 X65M.

A conceptual analysis was completed for each of the two Scenarios. This conceptual analysis included a high-level assessment of the required permits for the system; a high-level economic assessment of the operating system (from the perspective of the transport operator); and development considerations, such as pipe size, pressure requirements, equipment availability, population centers, potentially impacted environmental and cultural areas.

2.4 *Regional Connection*

This subtask researched the potential use of the CO_2 transport hub over the next 50 years. The project focuses on natural gas resources, which will continue to be an important part of the study area for the foreseeable future. This is evidenced by the production of natural gas in the Marcellus and Utica/Point Pleasant. Ohio, Pennsylvania, and West Virginia produced a combined 13,000,000 million cubic feet (mcf) of natural gas in 2024 (Energy Information Administration [EIA], 2025a). This accounted for nearly 30% of the natural gas produced in the United States that year. In addition, natural gas consumption is high in the project study area for a number of end users. The three states in the study area accounted for the use of around 3.5 billion cubic feet (bcf) of natural gas in 2023 (EIA, 2025b), around 11% of the gas used in the United States. Most of this was used for power production and residential end users. Around 1.5 bcf of the gas produced in 2023 was used by electric power end users. In addition, 55%, 45%, and 39% of homes using natural gas for heating in Ohio, Pennsylvania, and West Virginia, respectively (EIA, 2023).

Additional sources in the study area include industrial and electric power facilities, ranging from small sources that emitted less than 100,000 tonnes of CO_2 in 2023 to large electric power plants and industrial sources that emitted more than 1.0 million tonnes of CO_2 in 2023 (U.S. EPA, 2024). The sources within 10, 25, and 50 miles of each facility considered in the assessment and the RY1 Hub Area (A7) are shown in Figure 10, and the sum of the emissions, average emissions, and number of sources are detailed in Table 5. This work helps show the potential for hub expansion to include other sources in the region and the potential for individual sources considered in the network to serve as significant nodes in future development.

The mode selection process, outlined in Section 2.1, was applied to the sources within 150 miles of the RY1 Hub Area (Figure 11). The scenario was not optimized like Scenarios 1 and 2 above but was intended to show the function of the decisions trees on selecting modes for other sources in the vicinity of the RY1 Hub Area. Sources within 50 miles of the storage area were not considered because these sources would be closer to the storage area than the RY1 Hub Area. In the scenario presented in Figure 11, sources that emit 500,000 tonnes of CO_2 or more a year would be transported by pipeline because of logistical considerations with the other modes of transport.

Sources within 25 miles of the RY1 Hub Area would largely be transported by truck directly to the storage area (if they emit less than 100,000 tonnes per year) or by rail (if they emit more between 100,000 and 500,000 tonnes per year). One source near the RY1 Hub area could also be served by a pipeline because it is situated in an ideal area for pipeline development.

Most sources 25 to 75 miles from the RY1 Hub Area need to be trucked to a nearby railyard, pipeline inlet, or directly to the RY1 Hub Area. Other sources close to railyards could truck CO_2 to the railyard or construct spurs that would connect to these railyards. These sources largely emit between 100,000 and 500,000 tonnes per year. Other sources that emit between 100,000 and 500,000 tonnes per year but are not within five miles of a railyard may be serviced by pipeline branches that connect to pipeline trunk-lines, railyards or spurs, or directly to the RY1 Hub Area.

Rail is the most common selected mode for sources 75 to 150 miles from the source, particularly in Cleveland where there are several railyards. Alternatively, these sources may eventually be serviced by a pipeline, although its development may be complicated by the population center. Several sources, labeled as “other” are too small to be considered for dedicated pipeline infrastructure and are not close enough to a railyard to construct a spur (i.e., are more than five miles from the nearest railyard). Sources like these may be stranded without additional pipeline infrastructure, other transport options (like barge), or additional optimization beyond the scope of this exercise.

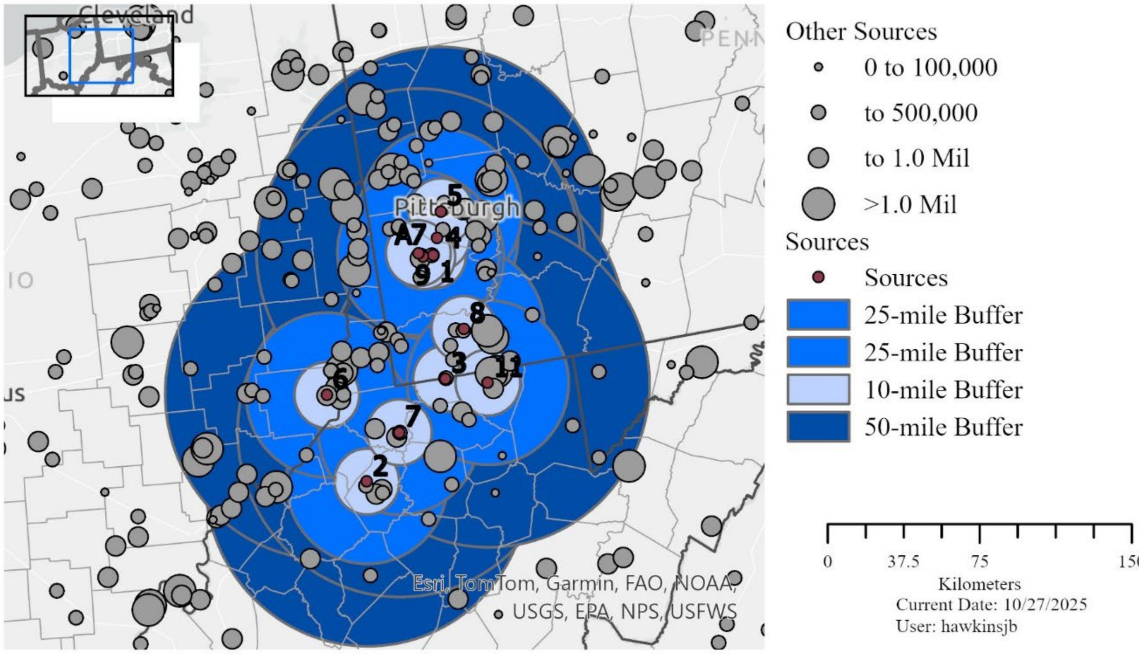

Figure 10. Map of sources considered in the project with 10-, 25-, and 50-mile buffers to show the other sources in the area that may be served by the hub. The emissions from these sources are detailed in Table 5.

Table 5. Other industrial and electric power sources within 10, 25, and 50 miles of the sources considered in this study. Source data includes the sum and average CO_2 emissions in 2023 and the number of facilities U.S. EPA, 2024).

Facility No.	10 miles			25 miles			50 miles		
	CO_2 (MMt/yr)		Count	CO_2 (MMt/yr)		Count	CO_2 (MMt/yr)		Count
	Sum	Mean		Sum	Mean		Sum	Mean	
1	0.3	0.06	4	15.4	0.55	28	47.8	0.54	89
2	0.4	0.09	4	12.2	1.22	10	28.8	0.52	55
3	0.1	0.03	3	25.4	1.02	25	43.4	0.64	68
4	0.2	0.08	3	7.4	0.25	30	51.3	0.57	90
5	0.3	0.04	8	8.9	0.26	34	45.9	0.53	87
6	5.5	0.61	9	6.2	0.29	21	44.0	0.68	65
7	0.2	0.06	3	14.7	0.77	19	40.3	0.68	59
8	3.5	0.58	6	12.8	0.61	21	48.9	0.62	79
9	0.2	0.07	3	15.4	0.53	29	50.9	0.53	97
11	8.9	2.2	4	13.2	0.83	16	33.2	0.53	62
A7	0.2	0.06	4	15.4	0.53	29	52.6	0.53	99

The intermodal hub is positioned well to take advantage of synergies with other carbon removal and CO_2-enhanced oil recovery (EOR) projects. The intermodal hub is in an area with significant federal investments. Projects like the ARCH2 Hub will provide an additional end-user for natural gas. The ARCH2 Hub seeks to connect producers of blue hydrogen (i.e., hydrogen produced from natural gas with CCS) with hydrogen transporters and consumers. The project also tracked nearby storage system development conducted by the Southern States Energy Board (SSEB) through its Phase III Carbon Storage Assurance Facility Enterprise (CarbonSAFE) effort (Wernette, 2024). These locations were considered for when developing the scenarios presented in Sections 2.1 and 2.2 but were ruled out because they were still under development at the time of the project. Additional carbon capture, storage (CCS) projects, and other carbon removal projects are mapped in Figure 12. These projects could serve as additional connections for a regional hub or additional redundancies to help defray risks of project investment.

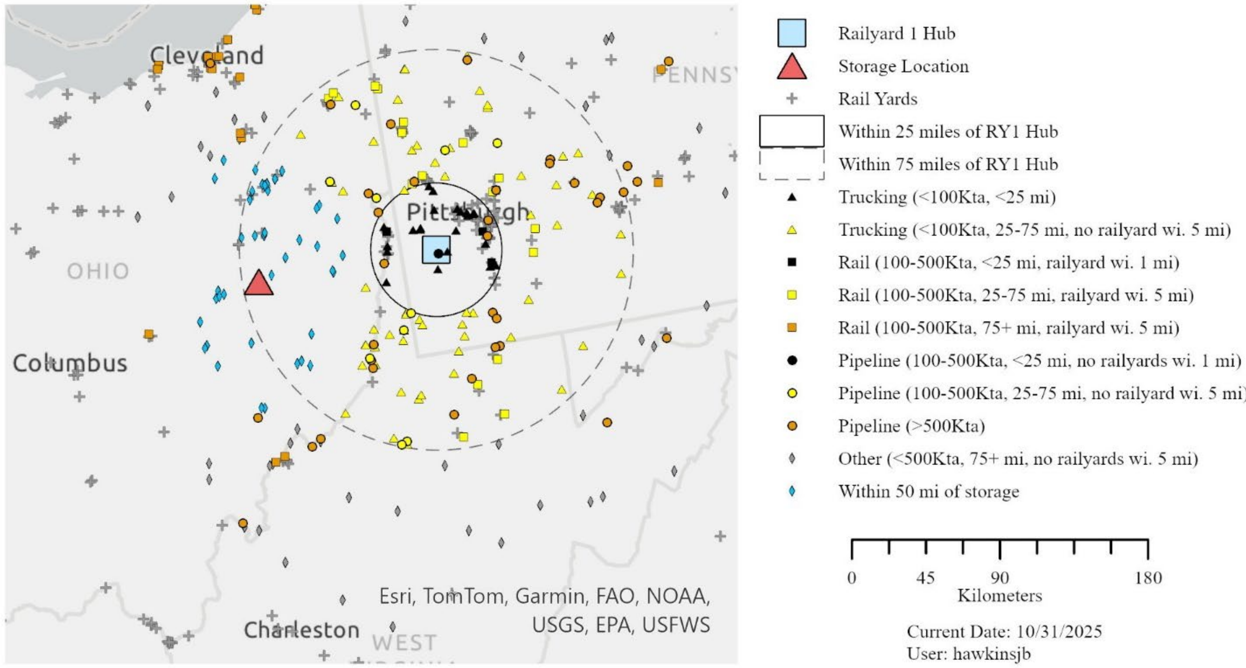

Figure 11. Mode selection for sources within 150 miles of the RY1 Hub Area. Modes were selected using the process outlined in Figure 3 (for sources within 25 miles of the RY1 Hub Area) Figure 4 (for sources 25 to 75 miles from the RY1 Hub Area), and Figure 5 (for sources more than 75 miles from the RY1 Hub Area). Additional optimization would be required for sources labeled as "other" or those within 50 miles of the storage area.

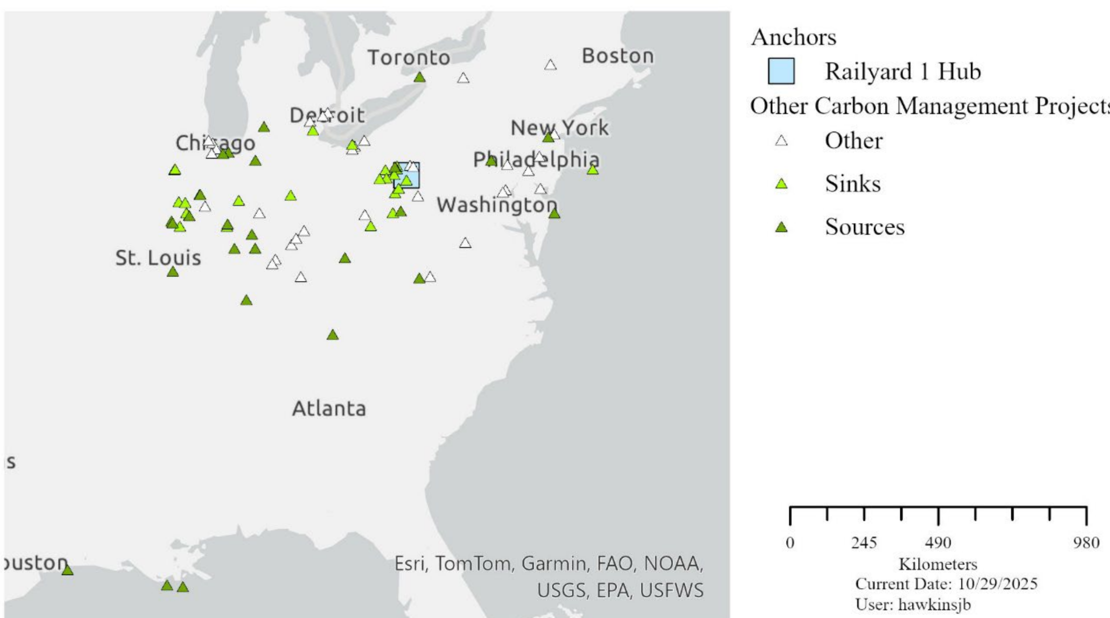

Figure 12. Additional carbon capture (sources), storage (sinks), and other projects near the RY1 Hub Area.

3.0 Regulations and Permitting

This task will result in information about the federal, state, and local regulations and permits needed for the intermodal designed transport hub. In addition, a land acquisition plan to ensure all necessary ROWs for the project can be acquired in future phases will be researched as part of this task.

3.1 Permitting and Regulatory Plan

The relevant federal, state, and local regulations and permits required for each mode of transport included in the hub were reviewed as part of this project. The analysis is summarized below with the full permitting analysis and matrix table in Appendix 1.

Federal Regulatory Framework: CO_2 pipelines are subject to multiple federal regulations. The Pipeline and Hazardous Materials Safety Administration (PHMSA) enforces safety standards under 49 C.F.R. Parts 190–199, which cover design, construction, operation, and emergency response. These rules aim to prevent accidents and ensure public safety. Environmental reviews under the National Environmental Policy Act (NEPA) are required for projects involving federal lands or funding. Additionally, permits under the Clean Water Act may be necessary for wetland and stream crossings. Permanent CO_2 storage is regulated through the EPA's Underground Injection Control (UIC) program for Class VI wells unless states have obtained primacy.

Pipeline Transportation

- PHMSA (Pipeline and Hazardous Materials Safety Administration, DOT)
  - Regulates pipeline safety (design, construction, operation, maintenance).
  - Requires detailed engineering plans, safety and emergency response documentation, and ongoing compliance audits.
- NEPA (National Environmental Policy Act)
  - Required for pipelines crossing federal lands or involving federal actions.
  - Involves environmental impact assessments, public engagement, and mitigation planning.
- USACE (U.S. Army Corps of Engineers) Section 404/10
  - Required for water crossings.
  - Requires site plans, impact analyses, and mitigation strategies.

Rail Transportation

- PHMSA (DOT)
  - Regulates hazardous materials packaging, labeling, and documentation.
- FRA (Federal Railroad Administration, DOT)
  - Sets safety standards for rail equipment, track, and operations.
- STB (Surface Transportation Board)
  - Approves new or modified rail lines, requiring environmental documentation.

Truck Transportation

- PHMSA (DOT)
  - Regulates hazardous materials transport, including packaging and documentation.
- FMCSA (Federal Motor Carrier Safety Administration, DOT)
  - Regulates vehicle and driver safety, requiring training and maintenance records.

State-Specific Requirements: State-level considerations for CO_2 transportation and permitting primarily revolve around property rights, environmental compliance, and regulatory authority for storage. All three states—Ohio, West Virginia, and Pennsylvania—define pore space ownership as belonging to the surface estate, requiring developers to secure rights through agreements or pooling mechanisms. Each state allows some form of unitization for storage projects, with consent thresholds ranging from 70% in Ohio to 75% in Pennsylvania, while West Virginia follows oil and gas pooling principles. Class VI injection wells, essential for permanent CO_2 storage, are regulated under the EPA's UIC program unless states have primacy; West Virginia currently holds primacy, while Ohio and Pennsylvania are pursuing it. These frameworks ensure that subsurface storage aligns with property rights and environmental safeguards.

Pipeline siting and construction lack dedicated CO_2-specific statutes in these states, creating uncertainty around eminent domain authority. Developers typically rely on negotiated easements or, in some cases, common carrier status to secure rights-of-way. Environmental permitting remains a critical component, including water obstruction permits for stream and wetland crossings, air permits for compressor stations, and erosion control measures under state programs. Public engagement requirements, liability transfer provisions, and long-term monitoring obligations vary by state but are increasingly emphasized to address safety and environmental justice concerns. Below are the primary regulatory state agencies.

Ohio

- ODNR (Ohio Department of Natural Resources)
  - Oversees oil and gas activities and injection wells.
  - Recently granted primacy for Class VI well permitting.
- PUCO (Public Utilities Commission of Ohio)
  - Regulates intrastate pipeline safety.
- ODOT (Ohio Department of Transportation)
  - Oversees hazardous materials transport by truck and rail.

Pennsylvania

- PA DEP (Department of Environmental Protection)
  - Reviews and monitors underground injection wells.
  - EPA remains the permitting authority for Class VI wells.
- PUC (Public Utility Commission)
  - Regulates intrastate pipeline safety.
- PennDOT (Department of Transportation)
  - Oversees hazardous materials transport by truck and rail.

West Virginia

- WVDEP (Department of Environmental Protection)
  - Permits and regulates underground injection wells.
  - Administers Class VI well program (recently granted primacy).
- PSC (Public Service Commission)
  - Regulates intrastate pipeline safety.
- WVDOT (Department of Transportation)
  - Oversees hazardous materials transport by truck and rail.

Local Requirements: In addition to federal and state-level requirements, CO_2 transportation projects typically require local permits and approvals. For pipelines, developers often need road crossing permits from county or municipal authorities, utility coordination agreements, and local zoning approvals for compressor stations or valve sites. Construction activities may also trigger stormwater management permits and erosion control plans under local ordinances.

For truck and rail transport, local permits generally include oversize or overweight vehicle permits for CO_2 tankers, issued by city or county transportation departments. Rail shipments require coordination with local emergency management agencies and compliance with municipal hazardous material handling ordinances. In some jurisdictions, additional fire safety and emergency response planning approvals are required to ensure community preparedness for CO_2 transport incidents.

Permitting Summary: The permits and processes required for this conceptual intermodal facility are consistent with previously studied CCS projects. Federal requirements, such as the application for a Class VI well permit or developing an environmental impact summary (EIS) through NEPA, can require a large amount of time and effort. These can take over two years in some cases to complete the required information and apply for appropriate approvals.

Most of the permits that are needed for construction are routine permits that require a short preparation period a modest application fee. They are also generally approved within a few weeks or months. Potential issues with permitting requirements could come from public comments or public opposition to the permit. In particular, the sitting of pipelines could possibly prove to be a time-consuming permitting process if formal objections are made to project plans. Permitting generally takes at least one month for approval (with a public comment period) if no comments are received. With comments, however, the process can take up to 12 months. Water quality permits, air quality permits, wetlands permits, and endangered species act permits also have a public comment period and/or iteration with regulators that could potentially delay the project. These permit applications need to be started at the project outset. Application fees are not exorbitant, but public engagement costs to avoid public protests and rejection will be a significant expense.

3.2 Land Acquisition Plan

The project, as envisioned, includes eleven CO_2 emission points (natural gas compressors serving natural gas gathering and transmission pipelines) approximately 135 miles of pipeline, four (4) compressor stations, and three (3) railroad transfer locations. Three CO_2 emission points are adjacent to the planned CO_2 pipeline and the captured and conditioned CO_2 will be injected directly into the CO_2 pipeline. CO_2 emissions from the other eight CO_2 emission points will be captured, conditioned, and transported by truck to one of the railroad transfer locations. An analysis was completed evaluating the estimates steps and affected area of the pipeline Right-of-Way (ROW) acquisition.

Affected Area: Table 6 summarizes the counties and property parcels that the pipeline will traverse, the length of the pipeline in the indicated county, and the total acreage for the property parcels in the indicated counties.

Table 6. Summary of Key Statistics for Planned CO_2 Pipeline

County and State	Miles of Pipeline	Property Parcel Count	Acreage
Doddridge, West Virginia	9.03	62	710.9
Greene, Pennsylvania	1.84	12	121.1
Marshall, West Virginia	27.31	166	1659.6
Monroe, Ohio	8.43	45	538.5
Tyler, West Virginia	26.2	148	1793.9
Washington, Pennsylvania	31.79	202	1951.8
Wetzel, West Virginia	30.15	167	2160.3
Total	134.8	802	8936.1

Land Requirements: The planned routing represents approximately 75% collocation with existing natural gas pipelines, powerlines, railroads, and road easements. The remaining 25% of the routing will require new easements. In either case, permission from landowners must be obtained to build the planned CO_2 pipeline.

It is anticipated that existing railyards can accommodate the required CO_2 transfer and storage equipment.

It is also anticipated that the eight CO_2 emission locations requiring truck transport of the CO_2 will be able to accommodate the CO_2 compression transfer equipment and have sufficient space to accommodate truck access, maneuvering, and parking. In the absence of adequate space at existing CO_2 emission locations, a truck transfer facility will require 5-10 acres to accommodate operations.

CO_2 compression stations typically require 5 to 10 acres of land to accommodate compression equipment, control buildings and electrical infrastructure, storage tanks, access roads, and safety buffers. This property will have to be acquired or leased by CO_2NNECTION Project Developers.

Regulatory Agencies: The project team developed permitting/notification matrices for each mode of CO_2 transportation in Ohio, Pennsylvania, and West Virginia. These matrices identify the agency having jurisdiction over the issue, permitting or notification requirements for each, any required studies, and typical timelines and costs for the permitting or notification activity.

Although the proposed pipeline is an interstate pipeline, the Federal Energy Regulatory Commission (FERC) does not currently regulate CO_2 pipelines. Note also that implementation of the eminent domain process for acquiring property for CO_2 pipelines is contentious and will be governed by evolving state regulations.

Right of Way Acquisition Sequence of Operations: Below are the list of tasks that need to occur to acquire the ROW:

<u>Task 1. Finalize Routing</u>

The conceptual route for the CO_2 pipeline has not been evaluated to determine "constructability" Determining constructability will require a visual assessment of the route and more detailed environmental and cultural assessments than those provided by the Pivvot® pipeline routing tool.

Estimated completion time: 3 months, in advance of all other tasks except Task 2, Public Engagement.

<u>Task 2. Public Engagement</u>

Develop and deploy a public engagement strategy to inform stakeholders about the pipeline project and the benefits it will produce. Identify opponents and develop plans to counter anticipated negative messaging.

Estimate completion time: From project inception through the life of the project.

Task 3. Research Titles and Identify Landowners

Engage a land services firm to conduct title searches and create a database of parcels, landowners, and contact information.

Estimated completion time: 3 months, beginning after completion of Task 1.

Task 4. Engage Landowners

Authorize the land services firm to contact landowners to negotiate easement agreements for the pipeline and purchase or lease agreements for property required for compression stations or truck transfer locations.

Estimated completion time: 6-12 months, beginning when information from Task 3 is available.

Task 5. Conduct Property Surveys and Environmental Studies

Conduct formal surveys to finalize the pipeline route and mark right-of-way boundaries. Perform necessary environmental and cultural resources surveys to ensure that mitigation plans are developed to protect endangered or threatened species, cultural resources, and sensitive environmental areas. Advance discussions with regulatory agencies that were initiated during Task 2.

Estimated completion time: 6-12 months following substantial completion of Task 4.

Task 6. Secure Permits and Regulatory Approvals

Conduct formal and more detailed meetings with regulatory agencies to further explain the carbon dioxide pipeline project. Prepare and submit the required notifications and permit applications to the agencies identified in Appendix 2. Maintain the public engagement strategy developed during Task 2. Participate in public meetings or hearings as required.

Estimated completion time: 18-24 months, following substantial completion of Task 5.

Begin Pipeline Construction: Pipeline construction can begin once all land has been acquired, all notifications have been made, and all permits have been obtained.

4.0 Techno-Economic Assessment

The transportation of CO_2 from point source emitters, such as natural gas processing plants, to designated injection wells is a critical component of CCS strategies aimed at reducing greenhouse gas emissions. Thus, it is crucial to understand the impact of different modes of transportation on CCS project economics and feasibility. In Task 4, a techno-economic assessment demonstrating a high-level cost analysis and BCA of the CO_2NNECTION intermodal transport hub was completed and is available as Appendix 2 to this report. In addition, a preliminary long-lead material and equipment list was developed. The techno-economic assessment and BCA explore the logistical and economic considerations of three primary transportation modes: truck, rail, and pipeline. The initial techno-economic assessment and BCA was submitted to DOE in July 2025; the project team refined the report into a final version that is included as Appendix 2 of this report. The results of the report are summarized in this section.

Each transportation method presents unique advantages and challenges in terms of scalability, cost-effectiveness, infrastructure requirements, and regulatory compliance. Trucking offers flexibility and low initial capital investment, making it suitable for small-scale or early-stage CCS projects, but it is limited by capacity and higher per-tonne transport costs. Rail transport provides a middle ground, offering greater volume capacity and moderate infrastructure needs, though it requires access to rail networks and transloading facilities. Pipelines, while capital-intensive and subject to stringent permitting processes, offer the most efficient and cost-effective solution for large-scale, continuous CO_2 transport over long distances. The BCA reviews the cost of each transportation method of the proposed multi-modal hub in two primary scenarios and three sub-scenarios to determine the impacts of more distant CO_2 sources on the network's economics.

A selection of scenarios and sub-scenarios was considered to understand the influence of various sources and modes of transportation on the project. Two primary scenarios are presented; these scenarios are defined in Table 7. The first gathers CO_2 from hypothetical sources that currently exist in the study area, focusing on small- and medium-sized sources throughout southwestern Pennsylvania, northern West Virginia, and eastern Ohio. The second scenario explores how the network would change with the introduction of a hydrogen plant in Doddridge County, West Virginia. The hydrogen plant is assumed to use natural gas as a feedstock and capture the CO_2 resulting from hydrogen production.

Table 7. Overview of scenarios and sub-scenarios considered in the discounted cash flow (DCF).

Scenario	Description
Scenario 1	Gathers CO_2 from hypothetical locations of sources that currently exist in the study area, focusing on small and medium-sized sources throughout southwestern PA, northern WV, and eastern OH
Scenario 2	Considers the impact of a newly constructed hydrogen plant on the intermodal transport hub
Scenario 1A – Only Pipeline	Same as Scenario 1 but excludes all methods of transportation and CO_2 sources other than pipelines and CO_2 originating at pipeline hubs. This scenario was used for the Economic Assessment only.
Scenario 1B – Fewer Trucking Connections	Same as Scenario 1 but excludes three trucking routes that connect at Railyard 2 and one trucking route that connects at Railyard 3. This scenario was used for the Economic Assessment only.
Scenario 1C – No Railyard 3	Same as Scenario 1 but excludes Railyard 3 and its associated CO_2 source. This scenario was used for the Economic Assessment only.

The project's net present value (NPV) and internal rate of return (IRR) were calculated using a discounted cash flow (DCF) model. Based on 45Q credits for geological storage from point-source capture, a revenue of $85 per net tonne of CO_2 transported was assumed (Carbon Capture Coalition, 2025).

Truck and rail cost estimates (both capital expenditures [CAPEX] and operating expenditures [OPEX]) were obtained using the methodology outlined by Myers et al. (2024) and thus follow the assumptions defined therein. Additionally, simplifying assumptions were made by the CO_2NNECTION team for the purpose of obtaining a high-level cost analysis. Transport costs and impacts for truck and rail were each calculated as one route transporting the total mass of CO_2 to be transported by each method. The geographical scale and location were selected as “Regional” and “East,” respectively, and the container type was assumed to be intermodal for both truck and rail

After further review by the CO_2NNECTION project team, it was determined that the Office of Fossil Energy and Carbon Management / National Energy Technology Laboratory (FECM/NETL) CO_2 Transport Cost Model originally specified in the Statement of Project Objectives (SOPO) is not capable of efficiently modeling pipeline networks. Instead, it is more applicable for single source/sink pipeline scenarios. As a result, pipeline capital cost estimates were largely obtained using the methodology outlined by McCollum and Ogden (2006), which estimates capital cost as a function of pipeline length and CO_2 mass flow rate as opposed to conventional inch-mile estimates. The FECM/NETL CO_2 Transport Cost Model (Morgan and Shih, 2024) was only utilized to estimate the CAPEX and OPEX associated with pumping the truck and rail CO_2 volume to pipeline specifications.

Mass flow rates for the intermodal transport network pipelines were rounded up to the nearest of the four values (1,000, 5,000, 10,000, or 20,000 tonnes per day) to match with one of McCollum and Ogden’s four cost curves. Costs were adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI) values (averaged over the year) for 2006 and 2024. Annual operating expenses were conservatively assumed to be 4% of capital expenses (Solomon et al., 2024), and other labor costs were assumed to be negligible.

Sub-awardee TRC Companies, Inc. (TRC) provided expertise in pipeline modeling and costing to further refine the techno-economic assessment. TRC used an inch-mile approach to develop a preliminary total installed cost estimate for the pipelines in Scenarios 1 and 2, wherein the product of the pipeline diameter in inches and the pipeline length in miles is multiplied by a unit-cost per inch mile.

TRC based the unit cost per inch-mile on recent expenditures for similar pipelines in the project area. These data were compiled from several sources, including from clients, industry organizations, and publicly available information. Total installed costs include, but are not limited to, elements such as materials (e.g., pipe, valves, and all associated components), construction (including post construction restoration), engineering, surveying, permitting (e.g., environmental, regulatory), and land acquisition. For the CO_2NNECTION project, historical pipeline costs were adjusted upward due to specialized material requirements for transporting CO_2, the unique geography of the Appalachian region, and geopolitical factors in the area (namely, the opposition of the installation of new pipelines, which results in higher permitting and land acquisition costs).

The inch-mile estimating approach for pipeline construction offers several advantages. Primarily, this approach is relatively quick and simple, making it useful for early-stage cost estimation when many aspects of the project are still unknown. Additionally, this method can be applied to pipelines of varying sizes and lengths, and it supports benchmarking by facilitating cost comparison with historical projects. However, the inch-mile approach is also subject to limitations. Most notably, this method does not account for project-specific complexities and instead relies heavily on the accuracy of the unit cost per inch-mile, which may or may not be representative of the CO_2NNECTION project’s specific pipeline material requirements and routing considerations. Completing the next level of cost estimation (Class 4 Feasibility Estimate, +/- 30%) will require additional work by construction, engineering, environmental, right-of-way, and permitting experts to further refine the routes and CO_2 sources.

4.1 Project Cost Estimate

A techno-economic assessment was completed for the selected hub node. The results of the assessment are presented in Table 8, Table 9, and Table 10. Scenario 1A, which uses only pipelines for transportation, was calculated to have the lowest breakeven price of $5 per net tonne of CO_2 and the highest carbon efficiency of 98.9%. Labor for this scenario was considered negligible, as it is not reliant on physically moving or connecting containers and vessells to the pipeline. Scenario 1 was found to have the highest breakeven price of $31 per net tonne of CO_2 and the lowest carbon efficiency of 97.6%. All scenario calculations yielded a positive internal rate of return.

Table 8. Key values for scenarios and sub-scenarios

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	Breakeven Price of CO_2 ($ / net tonne)
Scenario 1	1,788,817,379	42	97.6	31
Scenario 2	2,730,985,108	42	98.4	22
Scenario 1A	2,253,521,755	105	98.9	5
Scenario 1B	2,135,004,677	73	98.5	13
Scenario 1C	1,953,336,958	53	97.9	23

Table 9. CAPEX, OPEX, and labor costs for scenarios and sub-scenarios

Scenario	Truck CAPEX ($)	Rail CAPEX ($)	Pipeline CAPEX ($)	Total CAPEX ($)	Total OPEX ($ / yr)	Total Labor ($ / yr)
Scenario 1	57,443,758 ***(27%)***	86,920,611 ***(41%)***	68,047,622 ***(32%)***	212,411,991	30,768,949	6,813,574
Scenario 2	28,467,893 ***(9%)***	41,865,846 ***(13%)***	248,150,520 ***(78%)***	318,484,258	23,601,955	4,054,482
Scenario 1A	-	-	67,643,788 ***(100%)***	67,643,788	2,705,752	-
Scenario 1B	19,939,774 ***(18%)***	23,369,272 ***(21%)***	67,754,284 ***(61%)***	111,063,330	8,625,764	3,447,576
Scenario 1C	42,147,067 ***(26%)***	53,212,474 ***(32%)***	67,944,060 ***(42%)***	163,303,601	21,900,390	5,237,172

Table 10. Pipeline total installed cost estimates provided by TRC Companies, Inc.

	Scenario 1	Scenario 2
Pipeline route length (mi)	101.77	241.09
Pipeline cost (million $)	347	687
Compression / pumping facilities cost (million $)	54	114
Total installed cost (million $)	401	801

4.2 Business Case Analysis

The business case for operating the hub was developed using capital and operation and maintenance (O&M) expenses from Subtask 4.1. Potential sources of revenue, cash flows, earnings before interest, taxes, depreciation, and amortization (EBITDA), tax credits and liabilities, and project return on investment were also considered. Additionally, projections for future development scenarios were prepared and the project's potential benefits were quantified, including an evaluation of applying 45Q credits to project costs based on a market analysis of industry practices for offsetting infrastructure expenses.

The CO_2NNECTION intermodal transport network could generate revenue primarily through carbon credits in the compliance and the voluntary markets, wherein 45Q tax incentive credits could be sold to third parties. As of 2024, over 4,000 companies have committed to reaching voluntary decarbonization targets. Many of these companies rely on carbon credit purchases as well as infrastructure investments to meet their goals. Companies that are capturing their own carbon to fulfill environmental promises need a reliable transportation network if they are not sequestering or utilizing the captured carbon on site. One key requirement for on-site carbon sequestration is the site being located at a geological formation with appropriate storge capacity and characteristics. Projects capturing carbon at a site that does not meet geological requirements must transport CO_2 to a suitable location. Companies may be willing to pay for transportation services to meet voluntary or regulatory environmental commitments. As a transportation project, CO_2NNECTION would not be able to receive 45Q tax credits directly, but it could instead provide a necessary service to companies seeking to qualify.

The 45Q tax incentive provides tax credits to companies that capture and store or utilize carbon that would otherwise be released into the atmosphere. Currently, the credits offer between \$12 and \$85 per tonne of CO_2 sequestered. These credits can either be used to offset construction and operational costs or sold at a premium to third parties. When a company decides to transfer 45Q credits to a third party, the payment is not taxable to the seller. To qualify for 45Q, a facility must begin construction before 2033. The facility can then claim the credit for up to 12 years (AccountingInsights Team, 2025). Electing to receive the 45Q credits as transferable and selling them at a premium greater than the government rate provides a significant opportunity for generating revenue.

Potential financing structures for the CO_2NNECTION intermodal transport hub include traditional project financing, tax equity financing, and tax credit monetization. In traditional project financing, project developers secure debt financing from banks or other financial institutions to fund a portion of the project's capital costs. For tax equity financing, investors, such as corporations with tax liabilities, provide upfront capital, in exchange for a share of the tax benefits generated by the project, including the 45Q tax credits. Similar to tax equity financing, tax credit monetization project developers may also monetize the 45Q tax credits directly by selling them to third-party investors or financial institutions. This method provides immediate cash proceeds to the project developer, which can be used to fund project development or repay debt.

While there is a significant number of carbon capture facilities either under development or currently operating on the eastern half of the United States, there are no CO_2 pipelines operating east of the Mississippi River, and only one under development in Mississippi, Louisiana, and Texas (American Carbon Alliance, 2025). As the carbon sequestration market grows, more companies will need reliable transportation for their captured CO_2. Future projects or expansions of CO_2NNECTION could partner with companies to connect their facilities with an integrated carbon transportation system based on the original CO_2NNECTION project.

In the tristate region of Ohio, West Virginia, and Pennsylvania (home to a dense concentration of natural gas processing facilities, petrochemical plants, and coal-fired power stations), future deployment scenarios for CO_2 transportation are expected to evolve rapidly, assuming federal incentives continue to be offered, such as those from the 45Q tax credit and state-level decarbonization goals. In a moderate-growth scenario, CO_2 capture and transport infrastructure would expand incrementally, with early projects relying on truck and rail to move captured CO_2 to nearby injection wells, particularly in areas with limited pipeline access. In a high-growth scenario, driven by aggressive climate policy, carbon markets, and industrial decarbonization mandates, the region could see the rapid buildout of a shared CO_2 pipeline network, similar to the development of natural gas infrastructure in the early 2000s. Strategic deployment would likely prioritize clusters such as the Appalachian Basin, where geological storage potential aligns with high-emission industrial zones.

In 2024, there were 45 facilities globally applying carbon capture, utilization, and storage. These facilities had a combined carbon capture capacity of 50 million tonnes per year; however, to achieve the net zero emissions (NZE) scenario by 2050, 1,300 million tonnes of CO_2 will need to be captured annually by 2050 (International Energy Agency [IEA], 2024). It is estimated that approximately 1,178 million tonnes of CO_2 will be produced by U.S. industry in 2040 (EIA, 2024). A technoe-conomic assessment of the CO_2NNECTION project demonstrated the intermodal transport network's capability of transporting up to 1,630 net kilotonnes of CO_2 per year in Scenarios 1 or 2,135 net kilotonnes of CO_2 per year in Scenario 2. These capacities correspond to 0.14% and 0.18% of the CO_2 estimated to be produced by United States industry in 2040. A major pipeline project such as CO_2NNECTION could employ over 500 construction workers for the installation of approximately 100 miles of pipeline alone (Liquid Energy Pipeline Association, 2025a, 2025b). Net-Zero America estimates that over 100,000 kilometers or 62,000 miles of CO_2 pipelines could be needed in the U.S. by 2050 to achieve net zero emissions (Larson et al., 2021). Using this assumption, the Net-Zero America scenario would require up to 310,000 construction jobs to complete. In addition to construction jobs, pipeline installation projects generate hundreds of professional service and management jobs for engineers, architects, and contractors.

4.3 Long-Lead Material and Equipment

A list of equipment that is needed to support the hub was developed. The list was used to determine which of these critical supplies have a long-lead time for procurement, which is defined as materials or equipment that will require six months or more lead time. This subtask was completed primarily by TRC Companies, which has substantial experience with large-scale infrastructure projects. TRC Companies determined that many of the materials and equipment required for the hub have long lead times (Table 11). Additionally, it is pertinent to note that permitting requirements for the various intermodal facilities and the acquisition of right-of-way for the pipelines will take several years.

Table 11. Long-lead material and equipment list for the CO_2NNECTION project.

Item	Modes or Locations Requiring	Purpose	Lead Time
CO_2 conditioning equipment	Class VI well, CO_2 emission sources	Equipment to compress, dehydrate, and clean up CO_2 to meet pipeline or injection well specifications	12-18 months
Circuit breakers and switchgear	Substations servicing various intermodal operations	Control, protect, and isolate electrical circuits within the substation	6-12 months
Compressor/pump stations	Pipeline	Maintain CO_2 pressure and flow in pipeline	12-18 months
Cryogenic or pressurized tanks	Any location requiring CO_2 storage or buffering capacity	Storage of CO_2 at transfer locations.	6-12 months
Drilling rig and equipment	Class VI well	Construction of the Class VI well	6-12 months to schedule the drill rig use
Fittings and flanges	Pipeline, truck, rail	Connection of pipeline or piping components	6-8 months
Liquefaction and vaporization equipment	Truck, rail	Liquefaction of pipeline CO_2 for truck or rail transport. Vaporization of CO_2 from truck or rail tanks to pipelines	12-24 months
Metering and regulating stations	Pipeline	Measure and control CO_2 flow and pressure in the pipeline	8-12 months
Monitoring and testing equipment	Class VI well	Equipment for monitoring well integrity, CO_2 plume migration, and environmental impacts	6-12 months
Pipe and coatings, 8", 12", 18", 24"	Pipeline, truck, rail	Transport of CO_2 over long distances as well as at intermodal operation facilities	6-18 months, depending on size, grade, and coating requirements

Supervisory Control and Data Acquisition (SCADA) systems	All	Supports remote monitoring and control of the various intermodal operations	6-12 months

4.4 Discussion and Conclusion

Based on the results of the techno-economic assessment, the following conclusions were drawn:

1. All scenarios show economic viability when supported by the 45Q tax credit.
2. It is anticipated that the majority of capital costs would be incurred at the capture and/or injection sites, not by the transportation network itself.
3. The scenario with the lowest identified breakeven cost, Scenario 1A, only utilizes pipeline as a transportation method. This outcome is reasonable based on CO_2 transport literature (McCoy and Rubin, 2008).
4. Truck and rail are viable transportation methods for smaller carbon sources, but their implementation needs to be balanced by considering their impacts to the overall transportation project.

The economic models for pipelines implemented in the analysis, although robust, are becoming outdated and do not necessarily reflect recent technological advances or information specific to the CO_2NNECTION project. Additionally, these general models rely on national averages or outdated figures, which may not reflect the unique terrain, permitting environment, and labor costs in the Appalachian region today. Thus, sub-awardee TRC provided more recent and region-specific data for pipeline cost estimates to improve the quality of the techno-economic assessment and BCA. TRC estimated total installed costs of $401 million and $801 million for the pipelines in Scenarios 1 and 2, respectively. These estimates are higher than those determined in the original analysis, which is not unexpected. TRC's unit cost per inch-mile of pipeline is based on more recent financial data and accounts for elements that were not included in the original economic assessment, such as land acquisition, surveying, and permitting.

To further develop this BCA, areas for cost optimization across the proposed transportation network should be identified. This step would include tasks such as 1) evaluating economies of scale in pipeline diameter selection, 2) identifying opportunities for co-location with existing rights of way, and 3) researching potential for shared infrastructure among emitters. Furthermore, benchmarking CO_2NNECTION against comparable recent projects would highlight aspects of CO_2NNECTION that can be further refined to maximize the project's benefit.

5.0 Hazard Identification and Sensitive Areas/High Consequence Areas (HCAs)

The *Hazard Identification and Sensitive Areas/High Consequence Areas (HCAs)* Task had two subtasks: HAZID and ES&H Analysis. The results of the HAZID are presented in Appendix 3 and summarized below.

5.1 Hazard identification (HAZID)

The HAZID study included two parts: (1) an accounting of the potentially sensitive areas that might be impacted by the intermodal hub and (2) an assessment of the likelihood and severity of potential leakage scenarios from each transport mode. Surface conditions, including HCAs, critical infrastructure, and other sensitive areas, were identified using a process described by Battelle (2024). The project team used publicly available shapefiles to define or approximate the HCAs and sensitive areas, considered how the development of pipelines could impact these areas, discussed the prioritization of minimizing impacts, and presented possible mitigation options. Important impacts were evaluated using the Bowtie Risk Assessment methodology described by Alizadeh and Moshashaei (2015). This analysis included evaluations of top-line events (hazards), causes and consequences of the hazards, control measures to prevent hazards, recovery mechanisms to recover from a hazard, and threats to these control measures. The potential impacts of development were evaluated using a qualitative risk assessment, which included an assessment of the likelihood of the impact occurring (on a scale from 1-5) and its severity (also on a scale of 1-5). A Risk Ranking was calculated by multiplying the likelihood and severity. The qualitative assessment was through a risk roundtable during which the bowtie assessments were also evaluated and revised.

Pipeline, Rail and Trucking Hazards: CO_2 transport by pipeline, trucks, and rail carries distinct risks related to mechanical failure, environmental exposure, and public safety. Understanding these risks is essential for designing resilient infrastructure and implementing effective mitigation strategies, particularly in regions with active or planned CCS deployment. This section presents literature review of CO_2 transport infrastructure in the United States.

Carbon dioxide transport infrastructure has experienced a range of failure modes across pipelines, trucking, and rail systems. According to Xi et al. (2023), analysis of 112 accident records from the Pipeline and Hazardous Materials Safety Administration (PHMSA) reveals that equipment failure is the most frequent cause of pipeline incidents, accounting for over 53% of cases. However, this failure mode does not correspond to the highest economic or environmental impact. Natural force damage, though rare, results in the greatest economic losses (67.21%), while material failure, particularly manufacturing defects, contributes most significantly to carbon emissions (52.26%), see Figure 13. The regulatory definition of a CO_2 pipeline accident, as per 49 CFR §195.50, includes any event involving unintentional explosion or fire, release of more than five gallons of CO_2, casualties requiring hospitalization, or property damage exceeding $50,000.

Vitali et al. (2022) further analyzed PHMSA data from 1994 to 2021, identifying 113 incidents involving onshore CO_2 transmission pipelines. Notably, no fatalities were recorded and only one injury was officially reported, though the Satartia, Mississippi incident in 2020 involved 46 hospitalizations. According to these authors, the most common failure types included leaks, pinholes, connection failures, and valve discharges under unwanted conditions. Approximately 19% of incidents were linked to relief valves, while ruptures accounted for only 3%, confirming that leakage is the dominant failure mode. The average shutdown duration was around 53 hours, with extreme cases like Satartia requiring up to 246 days for full recovery.

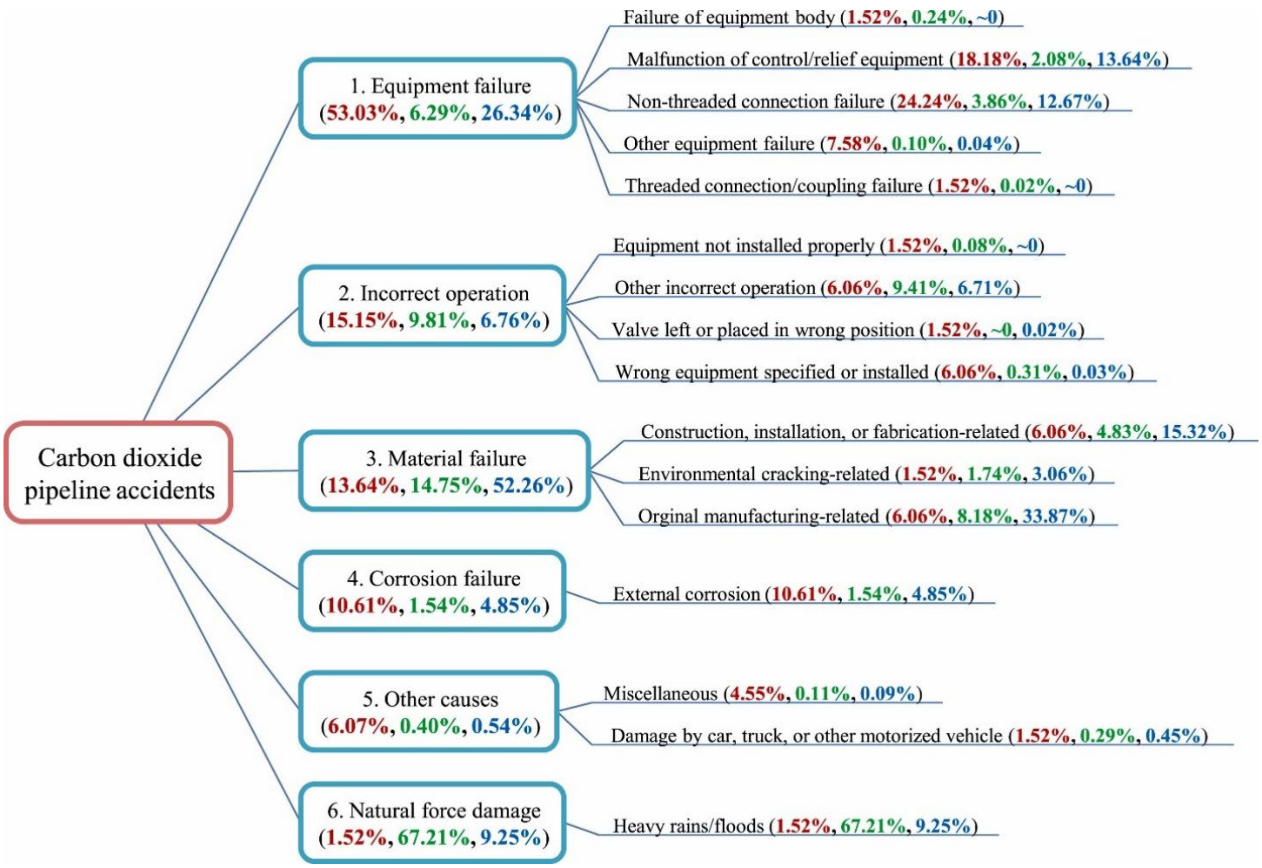

Figure 13. Primary and secondary causes of accidents in carbon dioxide pipelines (reproduced from Xi et al., 2023). Note: Red represents the proportion of accident frequency, green represents the proportion of economic losses, and blue represents the proportion of carbon emissions.

Duguid et al. (2022) conducted a risk assessment of accident data from PHMSA for four different pipeline types: natural gas transmission, natural gas distribution, non-CO_2 hazardous liquid, and CO_2 pipelines. The authors found that CO_2 pipelines carried significantly lower risk than the other three pipeline types, particularly because the severity of the consequences of failures are often lower for CO_2 pipelines, with the average CO_2 pipeline accident costing $23,808 (median of $6,334) compared to $740,000 to over $1.0 million (median of $25,000 to $122,000) for the other three pipeline types.

To complement these findings, updated PHMSA data through 2024 was compiled for this report and is presented in Figure 14. This data confirms the predominance of equipment failure, now accounting for 56 incidents, followed by material failure of pipe or weld (22 incidents) and corrosion (12 incidents). Other causes such as excavation damage, incorrect operation, and natural force damage remain less frequent. These results are consistent with previous studies (Xi et al., 2023 and Vitali et al., 2022). The proportional distribution of incident causes is further illustrated in Figure 15, where equipment failure represents 48% of all cases, followed by material failure (19%), corrosion (10%), and other causes each contributing less than 10%.

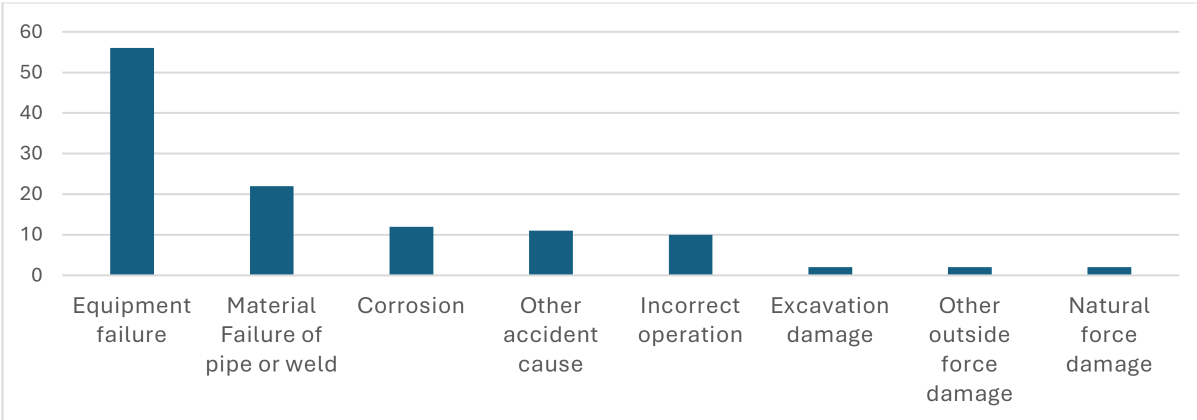

Figure 14. Number of incident causes in CO_2 pipelines reported to PHMSA (1994–2024) (Vitali et al., 2022).

The nature of release types in pipeline incidents is further detailed in Figure 15, which shows the distribution of failure modes from 1994 to 2024, based on PHMSA data. Leaks account for nearly 49% of all incidents, followed by relief valve discharges (18%) and pinhole leaks (16%). Ruptures remain rare at 3%, while 14% of cases lack specific release type information. These proportions align closely with the findings of Vitali et al. (2022), who noted that leakage is the dominant failure mode and that relief valves are frequently involved in unwanted discharges.

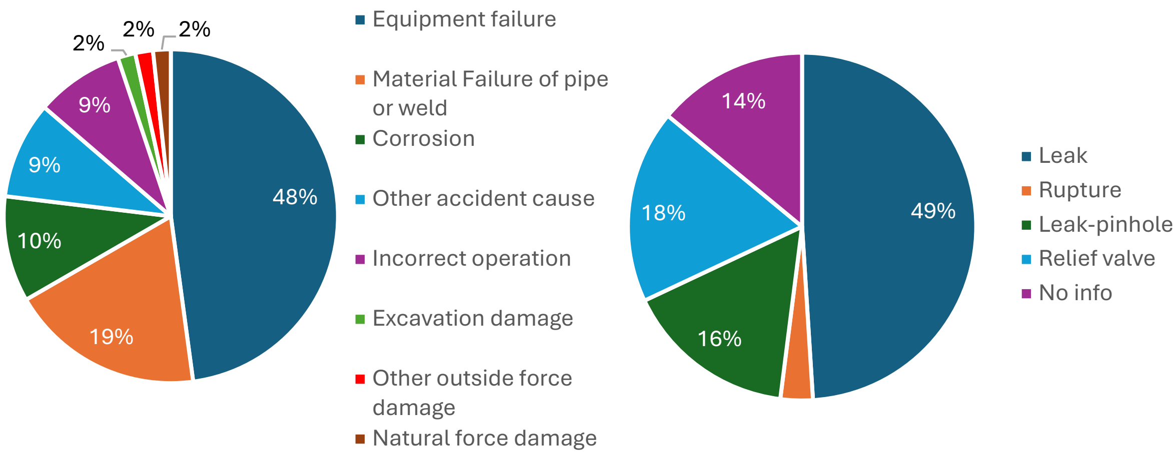

Figure 15. Causes (left) and types (right) for CO_2 pipeline accidents reported to PHMSA (1994-2024) (Vitali et al., 2022).

Trucking and rail transport, though less studied, show high incident rates but lower release volumes. Railcars, in particular, benefit from specialized design features that reduce the likelihood of failure. Nevertheless, the limited availability of public data on truck and rail incidents presents a challenge for comprehensive risk assessment. Highway trucking has a high incident rate among CO_2 transport modes, averaging 11.95 incidents per year between 2003 and 2022 (Ho et al., 2024). Most of these incidents were unscheduled releases, often due to over pressurization or component failure. Despite the frequency, trucking results in relatively low CO_2 release volumes 13.67 tonnes of CO_2 per year, compared to pipelines (2,553.33 tonnes of CO_2 per year). Rail transport, while less frequent in terms of incidents (3.25 incidents per year), also shows a low release volume (40.32 tonnes of CO_2 per year) and has maintained a steady transport volume of around 900,000 tonnes annually from 2013 to 2021. Failures in rail systems are typically linked to pressure relief valve malfunctions and frangible disc failures.

Maty and Wright (2022) and Ho et al. (2024) emphasize that CO_2 is transported in DOT 105-J500W tank cars, which are jacketed, insulated, and pressure-regulated to safely handle liquefied CO_2. These tankers are classified as Class 2.2 hazardous materials—non-toxic and non-flammable, under U.S. Department of Transportation regulations. Their specialized design has contributed to the relatively low incident rate in rail transport.

Trucking, though more prone to incidents, tends to result in smaller releases and is more flexible for short-distance transport. Rail offers a middle ground, with low incident rates and moderate release volumes, making it a viable option for regional CO_2 distribution. The likelihood and severity of CO_2 leaks vary significantly depending on pipeline characteristics, and failure type. According to Xi et al. (2023), pipelines in service for 0 to 10 years exhibit the highest frequency of accidents and the greatest proportion of carbon emissions, while those aged 11 to 20 years are associated with the highest economic losses. Bielka et al. (2024) reports an average of 5.11 CO_2 pipelines incidents per year between 2004 and 2021. Palmer et al. (2007) noted that CO_2 pipelines have a safety record comparable to natural gas and oil pipelines, with an incident rate of 0.00032 per km per year and no recorded fatalities from 1990 to 2002.

Leak types in CO_2 pipelines range from pinholes to ruptures, each with distinct implications. Mazzoldi et al. (2011) and Duncan and Wang (2013) describe pinholes as the most common failure mode, accounting for 65.1% of leakage incidents. These small, millimeter-scale holes typically produce visible white vapor plumes and are considered non-lethal and easily detectable. Punctures, which represent 15.1% of leakage incidents, are usually 2 to 4 inches in diameter and may depressurize slowly, delaying automatic valve shutoff. Ruptures, though rare, are the most severe, capable of releasing large volumes of CO_2 rapidly and generating shock waves with potentially fatal effects within a 5-meter radius (Mazzoldi and Oldenburg, 2013).

The volume and rate of CO_2 leaked is influenced by several factors, including pipeline diameter, hole size, operating pressure, distance between block valves as well as environmental and operational conditions, such as soil type, groundwater presence, pipeline depth, and impurities in the CO_2 stream (Koornneef et al., 2009; Nyborg et al., 2011) also play a role in leak probability and behavior. The behavior of leaked CO_2 in the environment is influenced by leak size, pipeline orientation, flow rate, CO_2 phase, and atmospheric conditions.

Upon release, liquid CO_2 vaporizes and, due to its density being 1.53 times greater than air, can displace oxygen and pose a serious asphyxiation risk to humans and animals (Bielka et al., 2024). The resulting CO_2 plume size behavior can depend on the type of leak. Hu et al. (2022) investigated the behavior of supercritical CO_2 released from high-pressure pipelines, combining large-scale experiments with computational fluid dynamics (CFD) modeling. Their findings show a three-stage concentration evolution: rapid rise, peak, and gradual decay. Larger leak diameters lead to higher peak concentrations and longer hazard distances. Spatial migration patterns reveal strong gradients in the near-field and slower dispersion in the far-field. The study also confirmed that temperature drops, phase changes, and radial jet expansion significantly influence the fate of leaked CO_2. Herzog et al. (2013) observed that larger leaks (e.g., 0.6 m) produce broader and taller plumes than smaller ones (e.g., 0.04 m), due to stronger inertial forces during the jet phase. The plume undergoes rapid vertical and lateral expansion, followed by slower passive dispersion. Shang et al. (2024) focused on buried pipeline leaks, noting that soil interaction leads to the formation of dry ice balls, frozen soil layers, and jet-induced cavities. These phenomena can alter soil pH, electrical conductivity, and organic matter content. This, in turn, can disrupt microbial communities and potentially affect groundwater quality.

After the leak occurs and the CO_2 plume forms and begins to move in the environment, hazard zones (i.e., where the plume could potentially impact human health or the environment) can be determined. Flow rate, leak size, pipeline geometry, leak orientation, and surrounding topography can all play a critical role in determining the size of the hazard zone. Small leaks generally pose limited risk, with dispersion zones confined to a few meters. However, large ruptures can affect areas up to hundreds of meters in radius, especially under low wind conditions that hinder plume dilution (Kuckshinrichs and Hake, 2015; Bielka et al., 2024). Leak orientation and location can also lead to different results. Bielka et al. (2024) conducted simulations that revealed that buried pipelines, while generally more contained, can still produce extensive dispersion zones if the rupture is large. In addition, the authors found that leaks from an above ground pipeline that were oriented toward the ground had larger dispersion zones.

The phase of CO_2 gas, liquid, or supercritical, affects dispersion behavior and hazards. Gas phase releases produce the smallest hazard zones (~2.0 m), while supercritical CO_2, due to its expansion potential, results in broader dispersion (~5.7 m) (Bielka et al., 2024). The initial jet phase of a CO_2 release has a significant impact on dispersion. Mazzoldi et al. (2009) demonstrated that jet velocity (~49 m/s) drives rapid entrainment of ambient air, diluting the plume more effectively than static models suggest. The direction of the jet influences plume shape more than wind speed or atmospheric stability, with horizontal releases producing higher ground-level concentrations. Hu et al. (2025) expanded on this by using neural networks and simulations to predict hazard boundaries for 4% CO_2, the Immediately Dangerous to Life or Health (IDLH) threshold defined by National Institutes for Occupational Safety and Health (NIOSH) (See Section 5.2).

Pipelines remain the most extensively studied and widely used mode of CO_2 transport due to their efficiency and capacity. However, they also pose the highest risk in terms of volume released during failures. Equipment failure is consistently identified as the most frequent cause of pipeline incidents, accounting for nearly half of all reported cases. Material failure and corrosion follow as secondary contributors. While these failures often result in minor leaks, large ruptures, though rare, can lead to significant environmental and economic impacts. The Satartia, Mississippi incident in 2020 serves as a critical example of the potential severity of CO_2 pipeline failures, despite the absence of formally recorded fatalities.

Overall, the findings underscore the importance of robust design, monitoring, and emergency response strategies for CO_2 transport infrastructure. While pipelines are indispensable for large-scale carbon management, their risks must be carefully managed through targeted maintenance and real-time leak detection systems. Rail and truck transport offer viable alternatives, particularly for regional distribution, but require further study to fully understand their risk profiles. Future work should focus on closing data gaps for non-pipeline transport modes and refining dispersion models to improve hazard prediction and mitigation planning.

Special Risk Topics: During the risk roundtable discussion, three topics potentially requiring additional investigations were identified: (1) the impact of acid mine drainage on pipelines, (2) the impact of road salt on pipelines, and (3) the impact of agricultural inputs (e.g., fertilizer and herbicides and pesticides) on pipelines. Preliminary literature reviews of these topics were completed and are presented below.

Impact of Acid Mine Drainage (AMD) on Pipeline Infrastructure: The safe and efficient transport of CO_2 through pipeline infrastructure is a critical component of CCS strategies. In regions with extensive mining histories, such as the Tri-State Area of Ohio, Pennsylvania, and West Virginia, environmental conditions pose unique risks to pipeline integrity. One of the significant concerns is AMD, a geochemically driven process that can severely impact carbon steel infrastructure through corrosion. AMD originates from the oxidation of sulfide minerals, particularly pyrite, upon exposure to oxygen and water. This reaction produces ferrous iron, sulfate, and hydrogen ions, significantly lowering the pH of surrounding waters. Subsequent oxidation of ferrous iron to ferric iron and its precipitation as iron hydroxide further contributes to acidity, often forming the characteristic orange sediments observed in AMD-affected streams. Microbial activity, particularly under low pH conditions, accelerates these reactions, intensifying the release of metals and acidity (Daniels et al., 2020). In the Appalachian coalfields, AMD is commonly associated with the weathering of metal sulfides in coal-bearing strata, resulting in drainage that is highly acidic, with elevated concentrations of iron, aluminum, manganese, sulfate, and trace elements such as copper, zinc, selenium, and arsenic (Daniels et al., 2020; Robb and Robinson, 1995).

The project area is particularly vulnerable to AMD due to its extensive legacy of coal mining and high-sulfur geology (Appalachian coalfields, 2025). In these areas, the natural buffering capacity of surrounding rock formations is often insufficient to neutralize acidic discharges, leading to persistent AMD generation (Daniels et al., 2020). Cravotta et al. (1999) identified a bimodal pH distribution in Pennsylvania's mine drainage, with one group of waters exhibiting strongly acidic conditions (pH 2.5–4) and another showing near-neutral pH (6.0 to 7.0), reflecting variability in geochemical and hydrological settings. The widespread presence of AMD in this region poses a significant threat to infrastructure, particularly pipelines, which are highly susceptible to corrosion under acidic and metal-rich conditions (Fortes et al., 2022). The corrosive nature of AMD is further exacerbated by factors such as dissolved oxygen, temperature, and microbial activity, all of which accelerate degradation processes in metallic materials (Fortes et al., 2020).

As shown in Figure 16, mining activity is widespread across the study area, with a dense concentration of abandoned coal mines along the Pittsburgh coalfield, particularly intersecting the Scenario 1 pipeline route. These legacy sites are known sources of AMD and pose a risk to pipeline infrastructure due to their proximity and the likelihood of acidic groundwater intrusion. Additionally, the Scenario 2 pipeline crosses areas with underground mines and active permit sites, which also present potential exposure to AMD. The spatial overlap between these mining-impacted zones and proposed pipeline routes highlights the importance of incorporating risk assessments into infrastructure planning.

The corrosive nature of AMD presents a significant threat to pipelines, particularly in regions with legacy mining activity. As Daniels et al. (2020) noted, AMD is chemically aggressive due to its low pH and high concentrations of dissolved metals and sulfates, which can initiate and accelerate corrosion processes in steel infrastructure. This is especially concerning for CO_2 transport systems, where pipeline integrity is critical for operational safety and long-term containment. Experimental studies have provided strong evidence of AMD's corrosive impact on carbon steel. Fortes et al. (2022) conducted a 30-week immersion test using thirty carbon steel plates exposed to AMD water with a pH of 2.9. Weekly measurements revealed progressive weight loss and volume reduction, confirming severe material degradation. The study established a direct correlation between exposure time and corrosion severity, highlighting the cumulative nature of AMD-induced damage. These findings are consistent with Fortes et al. (2023), who observed generalized corrosion across the entire surface of steel plates, resulting in section thinning and reduced structural integrity.

Further insights into the mechanical consequences of AMD exposure were provided by Sarmiento et al. (2024), who evaluated AISI 1020 carbon steel under both static (chemical corrosion) and dynamic (erosion corrosion) scenarios. In static conditions over 80 days, steel specimens experienced a 0.5% weight loss and a 28% reduction in fatigue strength. In dynamic conditions, degradation accelerated dramatically, with up to 35% weight loss and a 50% drop in fatigue strength within just four days. These results underscore the vulnerability of steel components not only in external pipeline structures but also in internal systems such as valves, joints, and compressors, which may be exposed to AMD.

The chemical aggressiveness of AMD is influenced by several factors, including pH, sulfate concentration, dissolved oxygen, temperature, and microbial activity (Fortes et al., 2020). Low pH values (<4.0) increase the solubility of iron oxides, while elevated sulfate levels contribute to the formation of expansive corrosion products. Temperature accelerates reaction kinetics, and acidophilic bacteria such as

Acidithiobacillus ferrooxidans enhance corrosion by producing sulfuric acid and forming biofilms. These combined effects lead to thinning, cracking, and fatigue failure in steel infrastructure, as observed in both laboratory and field studies (Daniels et al., 2020; Fortes et al., 2020, 2022, 2023, 2024; Sarmiento et al., 2024). Complementary research by Mohammed et al. (2023) on carbon steel immersed in sulfuric acid solutions further supports these findings. Over a 20-day period, the study documented weight loss, corrosion penetration rates, and mechanical property degradation, reinforcing the conclusion that acidic environments (whether synthetic or naturally occurring as AMD) pose a serious risk to steel durability. Taken together, these studies provide a robust foundation for assessing the chemical impacts of AMD on pipeline systems and emphasize the need for corrosion-resistant materials and protective strategies in CO_2 transport infrastructure.

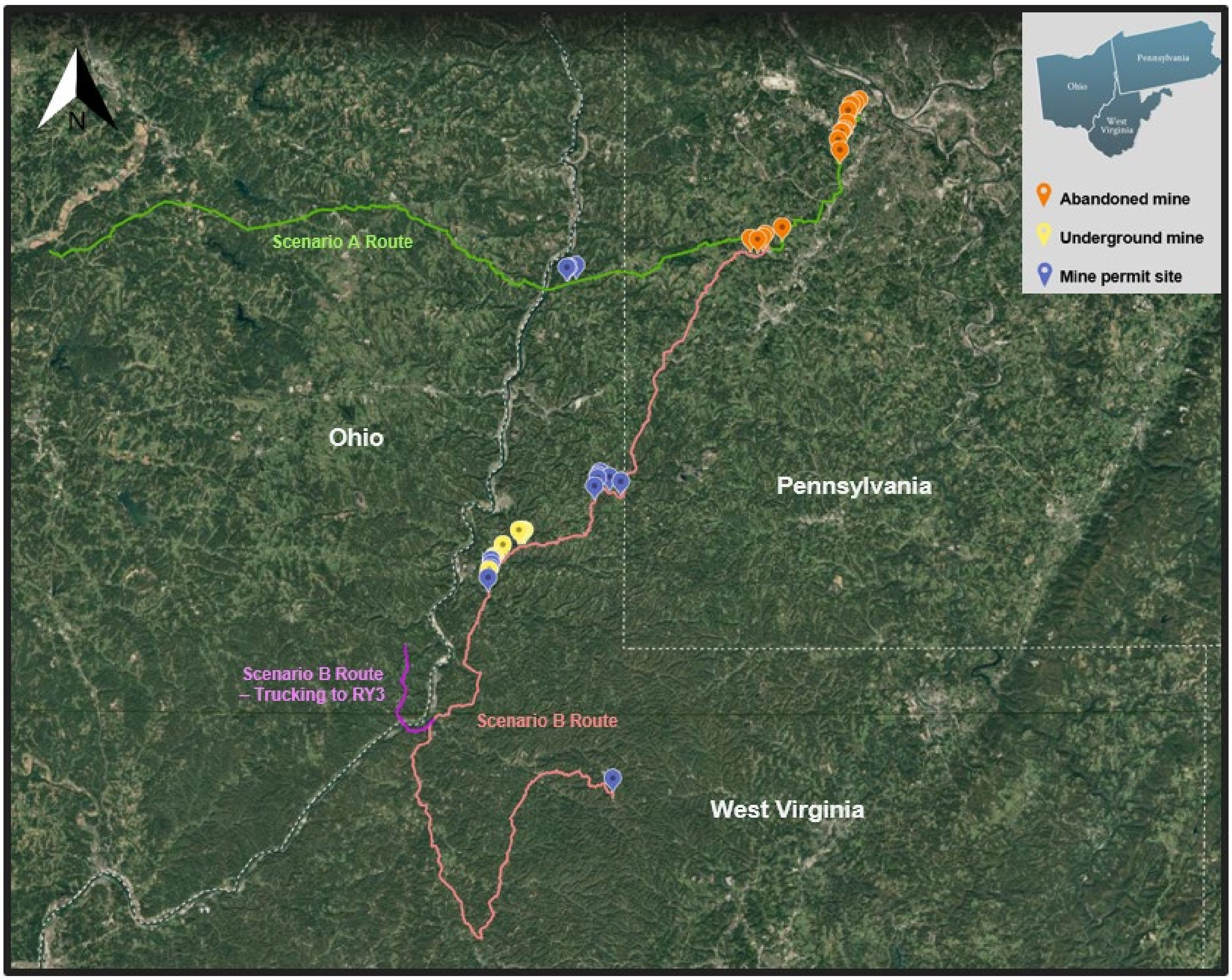

Figure 16. Proposed CO_2 transportation routes across the Tri-State Region with locations of abandoned, underground, and permitted mines. Co-locations were determined using the Pivvot Tool, developed by TRC Companies.

To mitigate the corrosive effects of AMD on pipelines and associated infrastructure, some operational and design strategies should be considered. First, it is essential to limit water exposure in pipeline systems because moisture accelerates corrosion, especially in environments with high sulfate and low pH levels. Additionally, direct exposure to radiant heating and high flow velocities should be avoided, as these factors increase turbulence and enhance the rate of chemical attack on steel surfaces. For systems handling acidic fluids, anodic protection has proven to be an effective method for reducing corrosion rates. This technique promotes the formation of a stable passive layer on the steel surface, significantly improving resistance to acid attack (Panossian et al., 2012). These recommendations are particularly relevant for both external and internal pipeline structures and equipment such as tanks, and valves that may be exposed to AMD or similar acidic environments.

The Impact of Road Salt on Steel*:* Several studies were found that cover the impact of road salt on steel. Pieper et al. (2018) studied the chloride levels in groundwater in various areas in and around highways. The highest salt levels in groundwater were found downgradient of salt storage barns, and the second highest concentrations were found within 30 meters of a major roadway. The authors conducted a laboratory experiment on well pipes and found increased corrosion with increasing chloride concentrations. Because major highways and road salt barns could increase the chloride concentrations in the subsurface, these must be mapped to ensure that pipeline infrastructure for the hub is properly protected and analyzed in these locations. Several authors have also studied the impact of chloride concentrations in soils on pipeline infrastructure (Song et al., 2017; Zhang et al., 2020; Deyab and Keera, 2012; Gao et al., 2022; Ahmed et al., 2023; Chung et al., 2021). These authors provide the impact of chloride on carbon steel in several different environments and concentrations. This information can be used to determine the impact of expected chloride concentrations that pipeline infrastructure will be exposed to. This will be an important component of a FEED study. Finally, alternative salts to rock salt have been developed and tested. Lawlor et al. (2023), for instance, tested road salts and less corrosive alternatives on steel rebar and found that the rock salt caused greater loss of material than the less corrosive alternatives. These rock salt alternatives should be explored to clear ice near hub infrastructure at the RY1 Hub Area.

Impact of Agricultural Inputs on Pipeline Infrastructure: Although a less common topic than the impact of rock salt, some studies did look at the impact of agricultural inputs on steel in the context of agricultural equipment. Sundaram et al. (2019); Fachikov et al. (2006); and Correa et al. (2023) studied the impact of ammonium fertilizers on steel corrosion. Sundaram et al. (2019) studied urea ammonium nitrate (UAN) and its impact on stainless steel and two alloys of mild steel to determine the best metal to use for a furrow open operated by a tractor. The authors found that the commercially available mild steel corroded more when exposed to UAN than the non-commercial mild steel. Fachikov et al. (2006) studied the impact of ammonium sulfate fertilizer on low-carbon steels. The author found that increasing concentrations of ammonium sulfate (range of 1% to 40%) is a less important factor than increasing temperature (range of 20 ºC to 60 ºC), both of which are positively correlated with corrosion rates. Correa et al. (2023) studied the impact of potassium chloride and urea on corrosion, mass loss, and thickness loss of galvanized steel and stainless steel to determine the impact of fertigation (fertilizer application during irrigation) on steel equipment. The authors found that stainless steel corroded less than galvanized steel in their experiments and that zinc coatings on galvanized steel were effective at protecting the underlying steel. Carbon steel is the most common material used for pipelines (Jansto, 2022); however, the results from Sundaram et al. (2019), Fachikov et al. (2006), and Correa et al. (2023) demonstrate the corrosive nature of nitrogen fertilizers on steel. This means that tests of materials used for pipes, safety equipment, and other equipment may be warranted for agricultural areas that have pipeline infrastructure.

5.2 Environmental Safety & Health (ES&H) Analysis

An ES&H analysis was completed for each relevant mode of transportation. The ES&H analysis included an evaluation of the air and water emissions; solid wastes; solvents and sorbents used in the technology; environmental degradation, bioaccumulation, and toxicological properties of substances used; potential dangerous or harmful properties of any chemicals used; regulatory compliance; analysis of potential engineering controls; and safe handling practices. These are defined in Table 12.

Table 12. ES&H Factors relevant to the intermodal hub.

Safety Factor	Analysis
Air and water emissions	Emissions from construction of pipelines and the RY1 Hub Area will include exhaust from equipment and dust during excavation and construction. Emissions from trucking from vehicles and fugitive emission of CO_2, particular from connections. Emissions from trains will include emissions from the engine and fugitive emissions of CO_2, particularly from connections. Proper engineering controls will be implemented to mitigate the impact of these emissions. CO_2 emissions from operations of RY1 Hub Area. These emissions may include the co-contaminants outline in Table 4.
Solids wastes	Solid waste may be expected from the construction of pipelines and the RY1 Hub Area. Solid waste would be expected to include the following: • Soil derived from excavating the site • Scaffolding, lumber, and other disposable construction materials and equipment • General refuse, including plastic coverings/wrappings, disposable personal protective equipment (e.g., Tyvek, disposable hearing protection, disposable gloves, etc.), and other trash All solid wastes will be reused, where possible, or recycled or disposed of in approved facilities to be identified during the FEED Study. Solid waste expected during operations is expected to be limited but may include non-hazardous waste derived from maintenance activities. This will be similar to the solid waste generated during construction activities and will be reused, where possible, or recycled or disposed of in approved facilities to be identified during the FEED Study. Singificant solid waste is not expected from rail or trucking operations.
Solvents and sorbents	Solvents and sorbents are not expected to be used in the RY1 Hub Area. Depending on the capture technology, amines or other capture derivatives may be present at trace concentrations.
Environmental degradation, bioaccumulation, and toxicological properties of substances used	When CO_2 escapes from a pressurized pipeline, the rapid phase change can form dry ice, with other CO_2 leaking a jet that expands, disperses as a cloud, and moves in the direction of the wind (Kieba et al., 2023; Vitali et al., 2021; Gorenz et al., 2023). Leaked CO_2 from pipelines has the tendency to accumulate in low-lying areas (Kieba et al., 2023; Liu et al., 2015). In these instances, CO_2 could become an asphyxiant. Eventually, CO_2 will escape into the atmosphere, a process helped along by wind (Vitali et al., 2021; Liu et al., 2015).
Potential dangerous or harmful properties of any chemicals used	The NIOSH published the health impacts of CO_2 exposure (NIOSH, 2019). Specific health hazards include "headache, dizziness, restlessness, paresthesia; dyspnea (breathing difficulty); sweating, malaise (vague feeling of discomfort); increased heart rate, cardiac output, blood pressure; coma; asphyxia; convulsions; frostbite (liquid, dry ice)" (NIOSH, 2019). Concentrations of CO_2 that identified by NIOSH as being : IDLH: 40,000 ppm Short-Term Exposure Limit (SEL) for 15 minutes: 30,000 ppm Permissible Exposure Limit (PEL) for 8-hour (weighted avg): 5,000 ppm
Regulatory compliance	All pipeline operations will comply with PHMSA and industry standards and adhere to 49 CFR §192. All other operations will comply with regulatory and industry standards and permitting requirements as described in Section 3 and Section 6 of this report.
Analysis of potential engineering controls	Potential engineering controls for pipeline operations, include SCADA systems, automatic and manual shutoff valves, markers, and other safety equipment. These systems will adhere to the standards set forth in 49 CFR §192 and consider additional protectiveness for pipelines routed through HCAs. Monitoring systems will also be implemented as part of the RY1 Hub Area to ensure leaks of CO_2 are identified and personnel can be alerted to potential hazards in the area.
Safe handling	Safe handling procedures, including safety equipment and PPE, will be defined during the FEED study.

6.0 Pre-FEED RY1 Hub Area

6.1 Process Description/Narrative

The RY1 Hub Area is intended to be an adaptable rally point for CO_2 transported in the intermodal transport hub (Figure 17). The pipeline in Scenario 1 and the additional pipeline in Scenario 2 are both routed here prior to transport. All CO_2 transported by truck or rail in both scenarios is gathered here prior to adding it to the pipeline for its final transport to the storage site via pipeline. Daily amounts of CO_2 by mode are plotted for each scenario. Items that require information that will be developed in future phases (e.g., vendor information or additional engineering) are highlighted in gray.

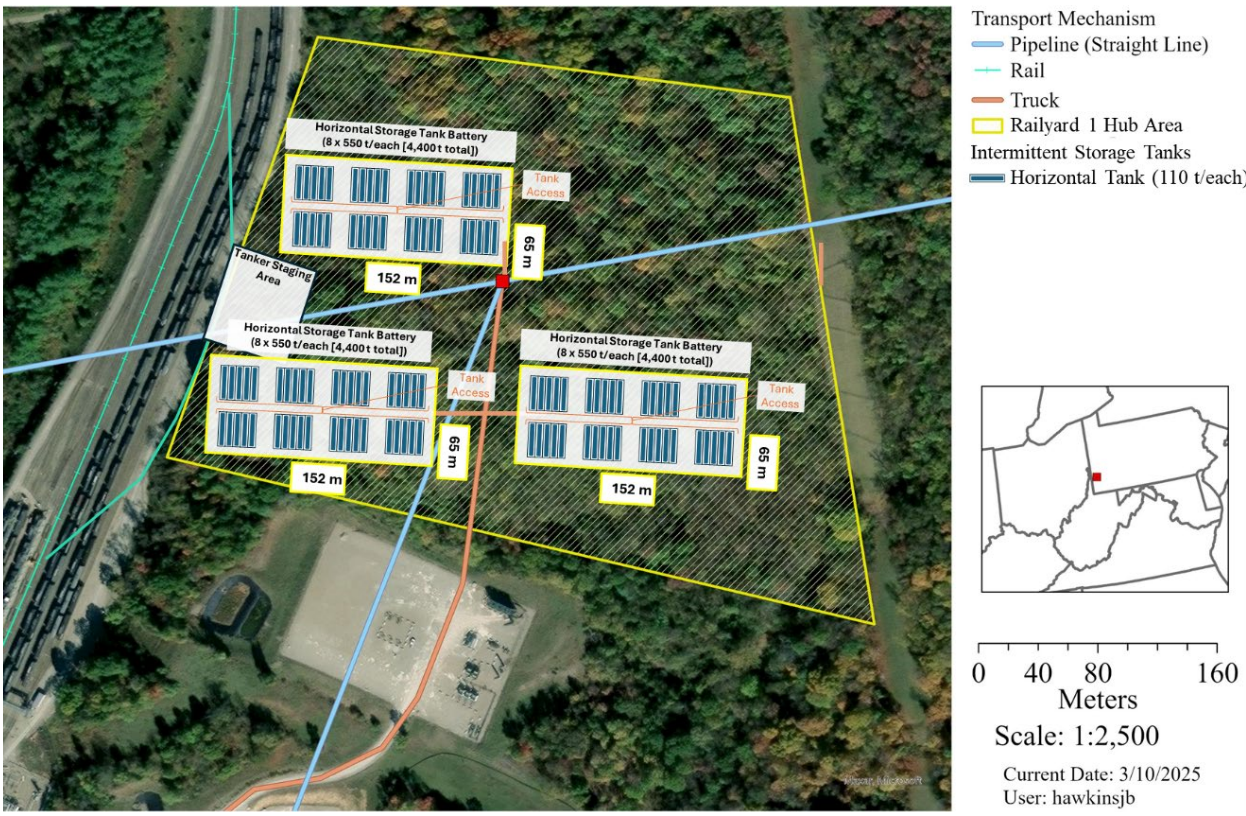

Figure 17. Map showing the conceptual RY1 Hub Area, including transport modes connecting to the area and above ground storage tanks.

Both Scenarios:

Modes. Trucks and rail will transport liquefied CO_2, and pipelines will transport supercritical CO_2.

Liquified CO_2 conditions. Liquefied CO_2 will meet the pipeline specifications in Table 4 and be between -20 to -40 ºF and 150 to 300 psi.

Supercritical CO_2 conditions. Supercritical CO_2 flowing into the RY1 Hub Area will meet the pipeline specifications in Table 4 and be between 40 to 90 ºF and 1600 to 1800 psi. Supercritical CO_2 flowing out of the RY1 Hub Area will meet the pipeline specifications in Table 4 and be between 40 to 90 ºF and 1800 to 2000 psi.

Above ground storage. Horizontal above ground storage tanks will provide intermediate storage of CO_2 from unit trains and trucks. CO_2 will be stored in a liquid form in these tanks. Pressure between 150 to 300 psi and temperature of less than 0 °C will be maintained during storage. These 110 tonne tanks will be staged in three batteries of 40 tanks each spread across the site (see Figure 17). This will provide a maximum above ground storage capacity of 13,200 tonnes at any given time.

Scenario 1: Scenario 1 is shown in the block flow diagram (BFD) provided in Figure 18.

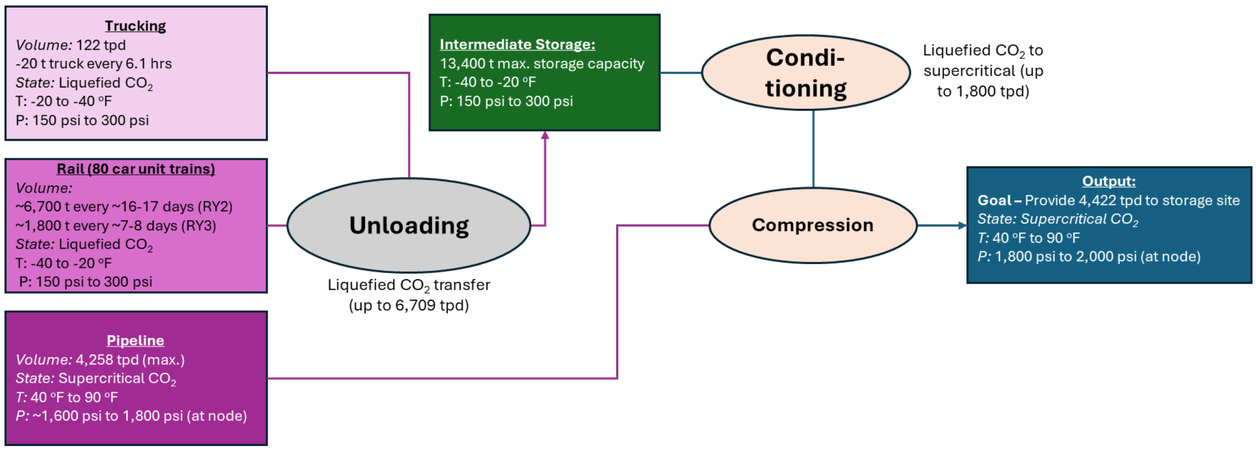

Figure 18. BFD for Scenario 1 at the RY1 Hub Area.

Total flow rates: CO_2 arriving via pipeline will remain in the pipeline and be supplemented by CO_2 from storage to maintain an average flow of approximately 4544 tonnes per day (Figure 19). For most days, the flow rate will be the maximum flow rate of 4645 tonnes per day. Lesser amounts flow from the system due to maintenance occurring on capture systems. The above ground storage of CO_2 onsite, however, ensures that at least 3000 tonnes of CO_2 are flowing every day. The CO_2 arriving at the site ranges from 1230 tonnes per day to 12,496 tonnes per day. Modal inflow is 4645 tonnes per day arriving via pipeline, truck, and rail (Figure 19). This is exceeded for 55 days of the year and not reached for 28 days of the year. During these times, CO_2 stored on-site will be used to ensure flow assurance.

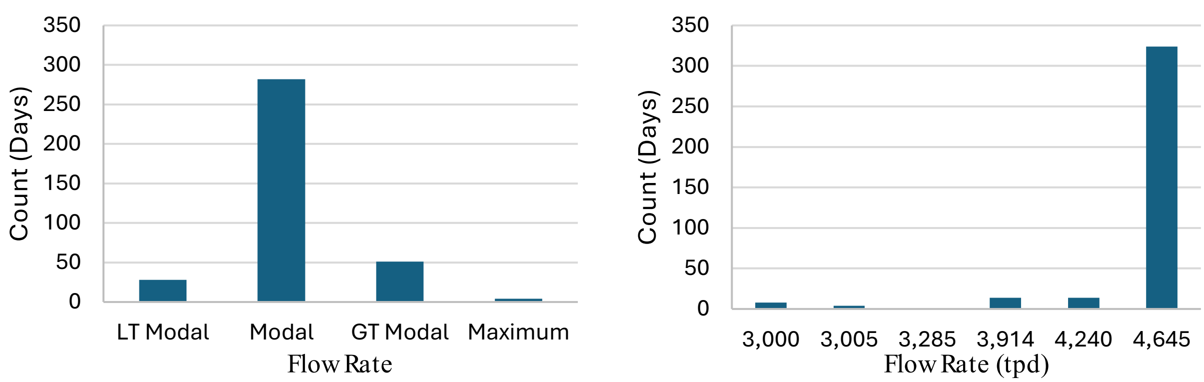

Figure 19. Number of days with specific inflow rates (left) and outflow rates (right) from RY1 Hub Area for Scenario 1. For inflow rates, the modal rate is 4026 tonnes per day. This modal rate is not reached for 28 days and amounts greater than the modal rate flow to the RY1 Hub Area 55 days of the year, including 4 where the maximum rate of 12,496 tonnes arrives via pipeline, truck, and rail. Modal outflow to the storage site is 4645 tonnes per day (the maximum amount of CO_2 transported), which is achieved 324 days out of the year. Lesser amounts flow from the system due to maintenance occurring on capture systems. The above ground storage of CO_2 onsite, however, ensures that at least 3000 tonnes of CO_2 are flowing every day.

Flow by transport mode: Inflow rates, by transport type, are shown for Scenario 1 in Figure 20. A truck arrives every 6 hours and delivers 20 tonnes of liquefied CO_2 per truck. This averages to be about 122 tonnes per day over the year. CO_2 will be transferred from trucks, assuming a rate of 500 kg/min, meaning the truck will be emptied in about 40 minutes.

A Unit Train of intermodal cars arrives carrying a total of around 1800 tonnes of CO_2 once every seven to eight days carrying liquefied CO_2. This will be offloaded and transferred to intermediate storage tanks using three lines (one for each storage tank battery) capable of transferring CO_2 at a rate of 500 kg/min, meaning the train will be unloaded in approximately 20-24 hours.

A Unit Train of tanker cars arrives carrying a total of around 6700 tonnes of CO_2 once every 16-17 days. This will be offloaded and transferred to intermediate storage tanks using three lines (one for each storage tank battery) capable of transferring CO_2 at a rate of 1000 kg/min, meaning the train will be unloaded in approximately 36-40 hours.

Pipeline provides most of the CO_2 arriving at the RY1 Hub Area transporting around 3914 tonnes of CO_2 per day to the RY1 Hub Area. CO_2 from the pipeline is considered must-move and thus will not go into intermediate storage but, rather, will continue transporting through the pipeline on to the storage area. The amount of CO_2 transported into the RY1 Hub Area via pipeline decreases to around 3700, 3000, and 1100 tonnes per day as individual gathering and boosting stations come offline for annual maintenance.

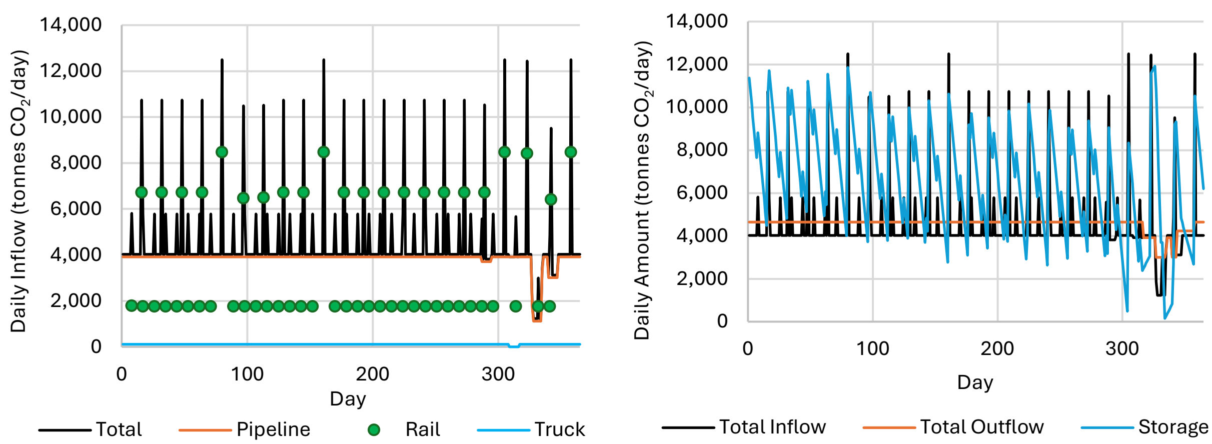

Figure 20. Daily inflow by Transport Mode (left) and Inflow and Outflow and Storge (right) at the RY1 Hub Area under Scenario 1.

Above ground storage requirements: In instances where pipeline flow drops below 3000 tonnes per day when larger sources are offline for maintenance, CO_2 from storage will be important to manage the minimum amount of flow required (3000 tonnes per day). Conditioning and compression of CO_2 from storage to the pipeline will occur at a rate of up to 1900 tonnes per day, although in most days only 730 tonnes or less will be required. Total above ground storage capacity at the RY1 Hub Area is 13,200 tonnes. Most days this capacity will not be used, instead around 3000 to 9000 tonnes of CO_2 (or around 20% to 70% of the overall capacity) is stored most days of the year (Figure 21, left). The storage outflow is constant over the year (Figure 21, right) except for when the storage must be built up over time in anticipation of the larger sources going offline for maintenance toward the end of the year (See Figure 20, right). During this time, flow is maintained at 3000 tonnes through an input of just under 1900 tonnes a day from storage for seven days and around 1200 tonnes a day from storage for five additional days.

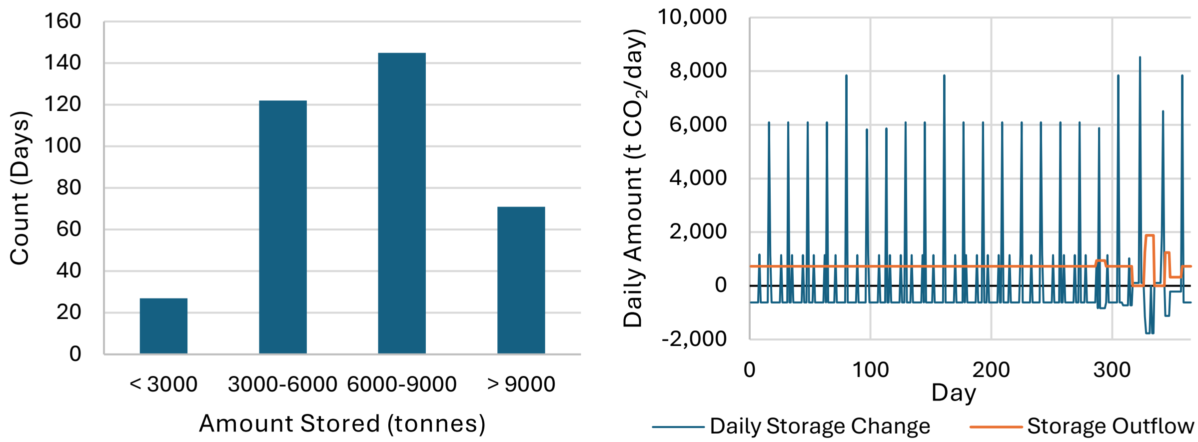

Figure 21. Number of days with specific volumes in above ground storage (left) and storage outflow and daily change in storage (right) at the RY1 Hub Area under Scenario 1.

Scenario 2: Scenario 2 is shown in the BFD provided in Figure 22.

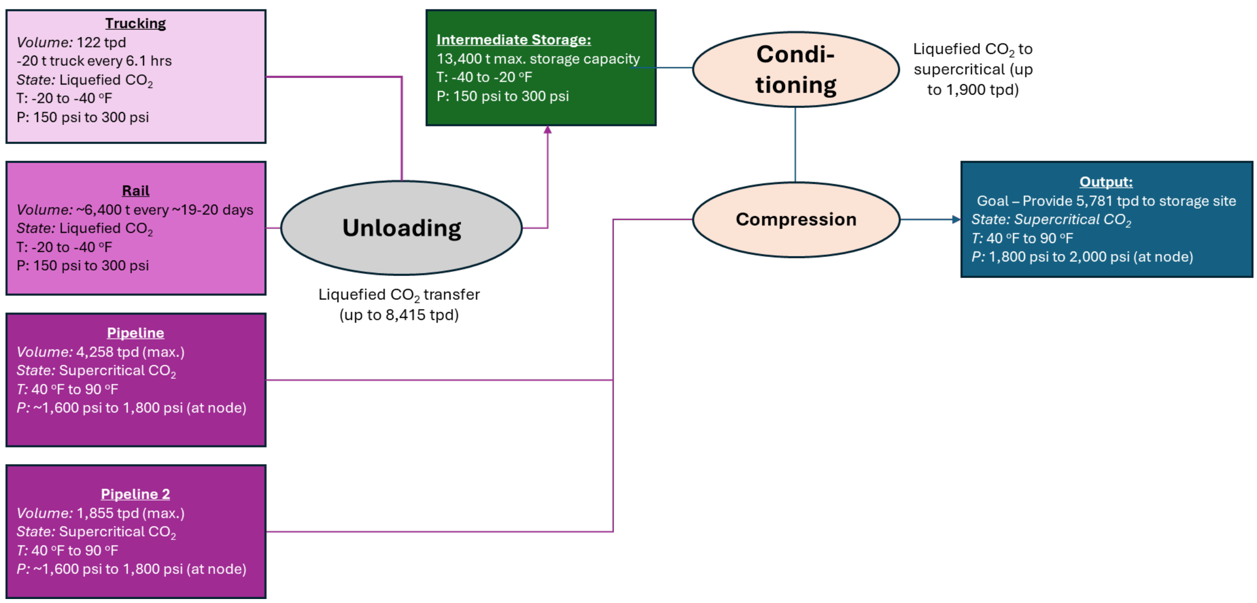

Figure 22. BFD for Scenario 2 at the RY1 Hub Area.

Total flow rates: CO_2 arriving via pipeline will remain in the pipeline and be supplemented by CO_2 from storage to maintain an average flow of around 5927 tonnes per day (Figure 23, left). For most days, the flow rate will be 5919 tonnes per day or the maximum flow rate of 6300 tonnes per day. Lesser amounts flow from the system due to maintenance occurring on capture systems. The above ground storage of CO_2 onsite, however, ensures that at least 3800 tonnes of CO_2 are flowing every day. The CO_2 arriving at the site ranges from 2824 tonnes per day to 12,440 tonnes per day. Modal inflow is 5731 tonnes per day arriving via pipeline, truck, and rail (Figure 23, right). This is exceeded for 17 days of the year and not reached for 49 days of the year. During these times, CO_2 stored on-site will be used to ensure flow assurance.

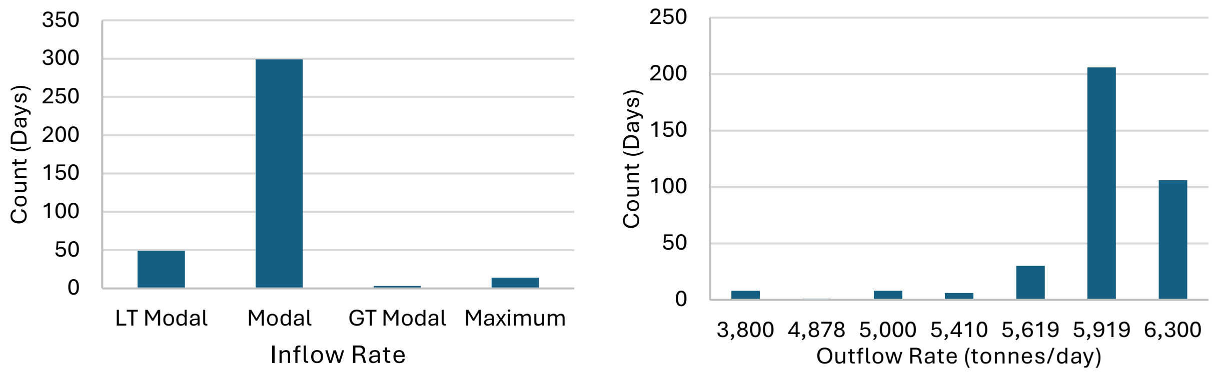

Figure 23. Number of days with specific inflow rates (left) and outflow rates (right) from RY1 Hub Area for Scenario 2. For inflow rates, the modal rate is 5731 tonnes per day. This modal rate is not reached for 49 days and amounts greater than the modal rate flow to the RY1 Hub Area 17 days of the year, including 14 where the maximum rate of 12,440 tonnes arrives via pipeline, truck, and rail. Modal outflow to the storage site is 5919 tonnes per day, which is achieved 206 days out of the year. The maximum amount of CO_2 transported per day (6300 tonnes) is reached 106 days out of the year. Lesser amounts flow from the system due to maintenance occurring on capture systems. The above ground storage of CO_2 onsite, however, ensures that at least 3800 tonnes of CO_2 are flowing every day.

Flow by transport mode: Inflow rates, by transport type, are shown for Scenario 2 in Figure 24. A truck arrives every 6 hours and delivers 20 tonnes of liquefied CO_2 per truck. This averages to be about 122 tonnes per day over the year. CO_2 will be transferred from trucks, assuming a rate of 500 kg/min, meaning the truck will be emptied in about 40 minutes.

A Unit Train of Tanker cars arrives carrying a total of around 6700 tonnes of CO_2 once every 16-17 days. This will be offloaded and transferred to intermediate storage tanks using three lines (one for each storage tank battery) capable of transferring CO_2 at a rate of 1000 kg/min, meaning the train will be unloaded in approximately 36-40 hours.

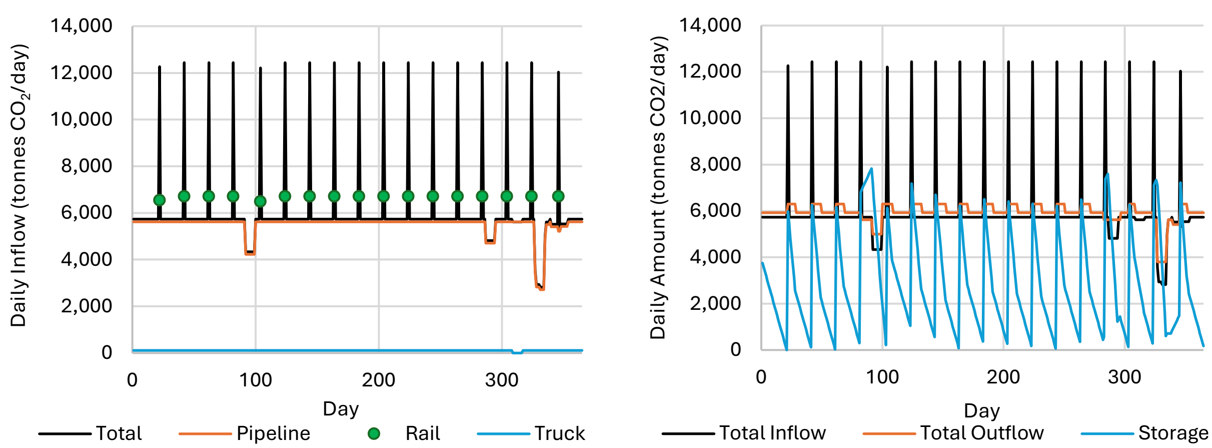

Figure 24. Daily inflow by Transport Mode (left) and Inflow and Outflow and Storge (right) at the RY1 Hub Area under Scenario 2.

Pipeline provides most of the CO_2 arriving at the RY1 Hub Area transporting around 3914 tonnes of CO_2 per day to the RY1 Hub Area. CO_2 from the pipeline is considered must-move and thus will not go into intermediate storage but, rather, will continue transporting through the pipeline on to the storage area. The amount of CO_2 transported into the RY1 Hub Area via pipeline decreases to around 3700, 3000, and 1100 tonnes per day as individual gathering and boosting stations come offline for annual maintenance. A second pipeline from northern West Virginia supplies additional CO_2.

Summary of equipment / process flow diagram: The process begins with a CO_2 delivery truck containing liquefied CO_2 at low temperature and moderate pressure or providing CO_2 from the temporary storage tanks. A cryogenic pump transfers the liquid from the truck/tanks and boosts its pressure to around 300 psig. This pump is designed for low-temperature service and prevents cavitation by maintaining adequate suction pressure. The vaporizer heats the pressurized liquid CO_2 to convert it into gas. This step ensures the fluid is in the correct phase for compression. Vaporizers can be ambient air, steam, or electrically heated units, and they include temperature and pressure controls to avoid dry ice formation.

After vaporization, the CO_2 gas enters a multi-stage compressor system. Each stage progressively raises the pressure to pipeline specifications (typically 1,500–2,200 psig). Interstage cooling is used to manage temperature rise and prevent excessive thermal stress. Compressors are equipped with vibration monitoring, pressure and temperature sensors, and recycle valves for control. The final stage is an aftercooler, which reduces the temperature of the compressed CO_2 to near ambient (60 °F) before entering the pipeline. This cooling step ensures compliance with pipeline specifications and protects downstream equipment. Heat exchangers are typically air-cooled or water-cooled, with flow and temperature control loops. A summary of the equipment and conditions is shown below in Figure 25.

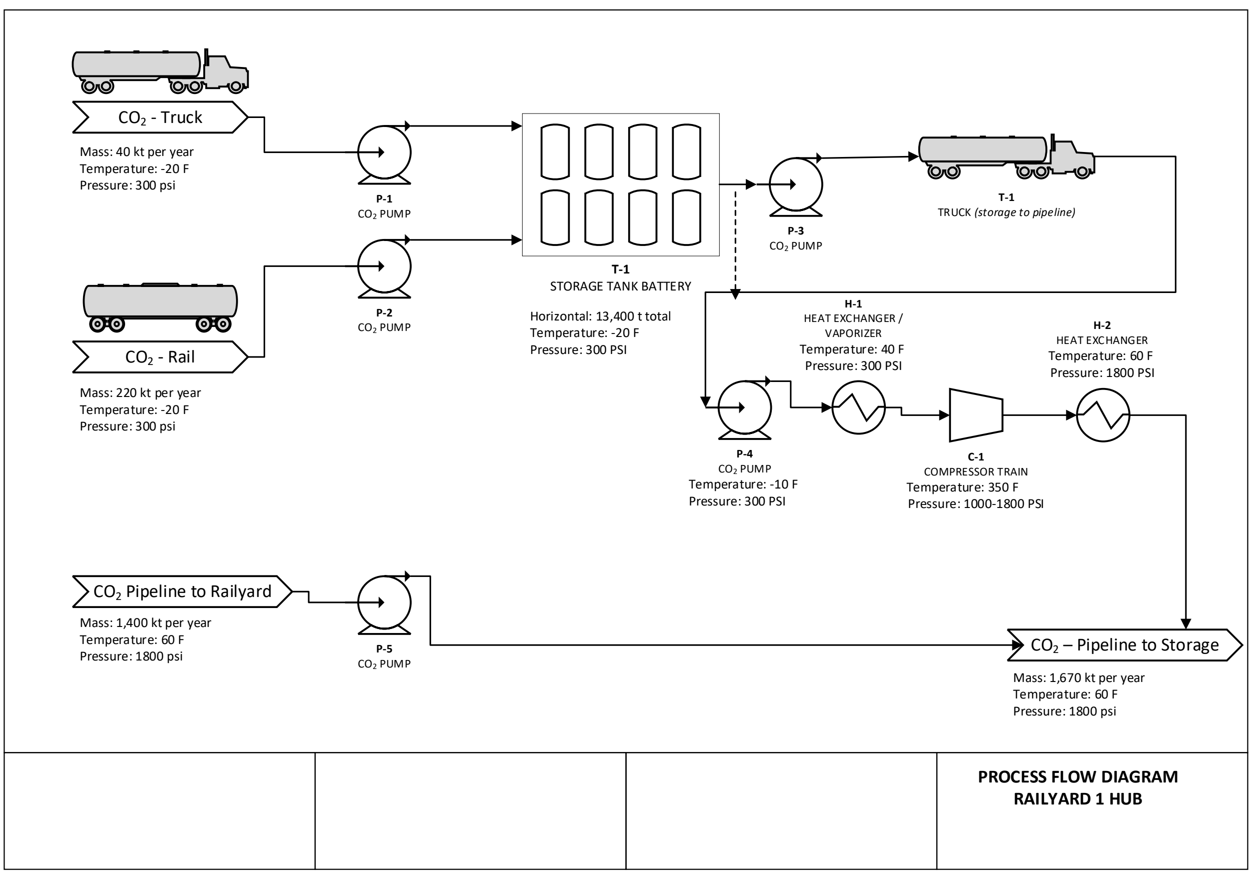

Figure 25: High-level Process Flow Diagram for Railyard 1.

One alternative equipment configuration uses a high-pressure cryogenic pump to raise the pressure of liquid CO_2 directly above the supercritical threshold (~1,070 psia). After pumping, the fluid passes through a heater to increase its temperature above 60 °F, ensuring it becomes a supercritical fluid. This approach eliminates the need for a vaporizer and multi-stage compressors, significantly reducing energy consumption since pumping liquid requires far less work than compressing gas. However, it demands specialized pumps capable of handling very high pressures and precise temperature control to avoid dry ice formation during heating. This configuration is common in supercritical CO_2 extraction and can be adapted for pipeline injection where supercritical conditions are acceptable.

6.2 Codes and Standards

The intermodal hub network is located in northern West Virginia, eastern Ohio, and southwestern Pennsylvania. The Railyard 1 Hub Receiving Area is in Washington County, Pennsylvania. Codes and standards applicable to the study are shown in Table 13.

Table 13. Applicable Codes and Standards for the RY1 Hub Area.

Area	US Requirements
Control Building	-International Fire Code (IFC) -International Building Code (IBC) -NFPA (Fire Suppression) -American Society of Civil Engineers (ASCE) 7 (Building Foundations) -Occupational Safety and Health Administration (OSHA) Requirements
Electrical	Developed Later with Additional Specifications
Intermediate Storage – Horizontal Tank	-American Society of Mechanical Engineers (ASME) Section VII, Div. 1 -American National Standards Institute (ANSI) Schedule 80 seamless pipe/isolation valves (Engineering Toolbox, 2003) -Relief valves (safety)
Intermediate Storage – Vertical Tank	-ASME Section VIII, Div. 1 -ANSI Schedule 80 seamless pipe -Relief valves (safety)
Piping	-ANSI Schedule 80 (Standard Pipe Specifications) -Det Norske Veritas (DNV) RP-J202 (Design and Operation of CO_2 Pipelines) (International Standard) -American Petroleum Institute (API) (2022) -49 CFR §192
Compressors	Developed Later with Additional Specifications
Heat Exchangers	Developed Later with Additional Specifications
Health Safety and Environment	-OSHA 1910 -OSHA 1910.36-37 (Means of Egress)

6.3 Operational Conditions (Site and Climate Data)

This section defines the environmental and operational conditions under which the Railyard 1 Hub Area (pre-FEED) system must operate, including location and elevation information, pressure, temperature, wind, precipitation, soil, seismic conditions, corrosive conditions, and current land use.

Plant Location and Elevation:

- **Area:** 1.367 million ft^2 (127,400 m^2) / 31.4 acres (0.127 km^2) (Figure 26)
- **Perimeter:** 4,820 ft (1,470 m)
- **Elevation:** 1096 ft amsl (334.1 m amsl) to 1,259 (383.7 m amsl). Gently sloping from east-northeast to west-southwest. Average slope of approximately 0.1. Southern portion of site has a slope of approximately 0.02 (Figure 27)

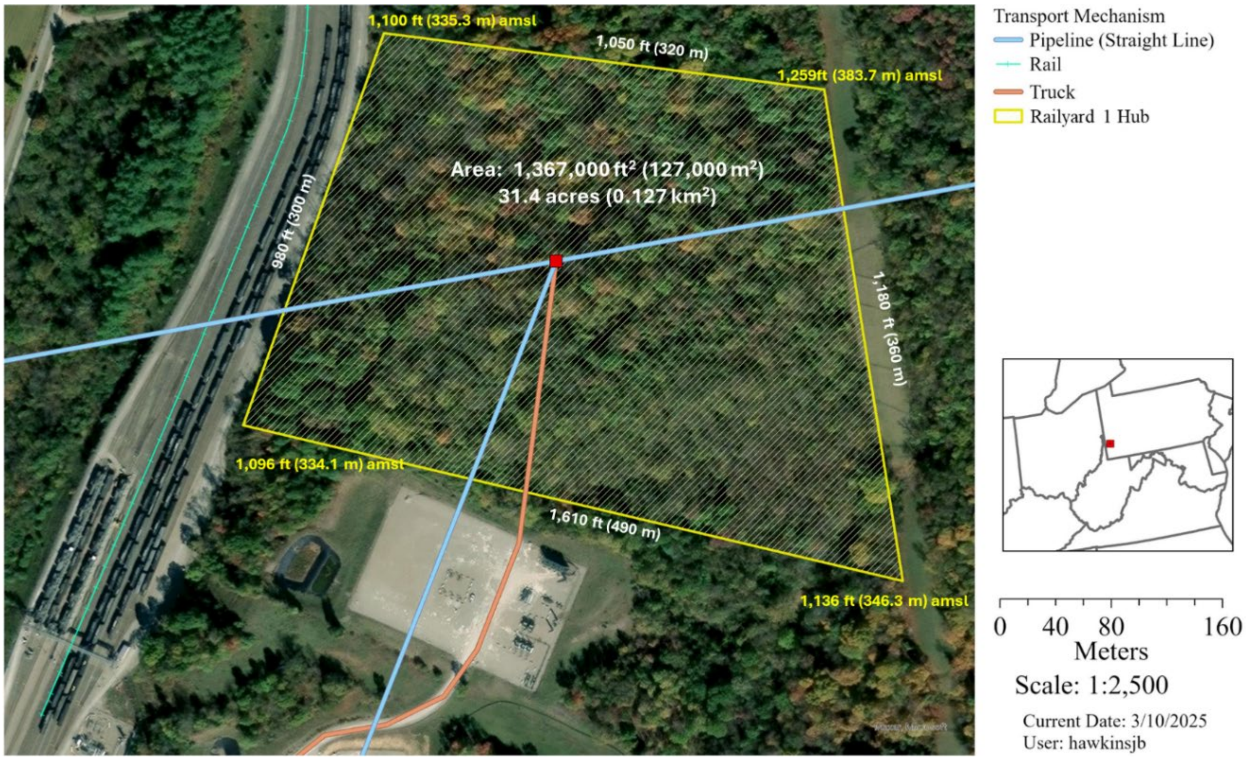

Figure 26. Land sat image of the Railyard 1 Hub Area. The yellow hashed area is the potential location for the hub. The elevations of the corners of the lot are shown in yellow text. The linear distance of the edges of the lot are shown in white text. The area of the lot is also shown.

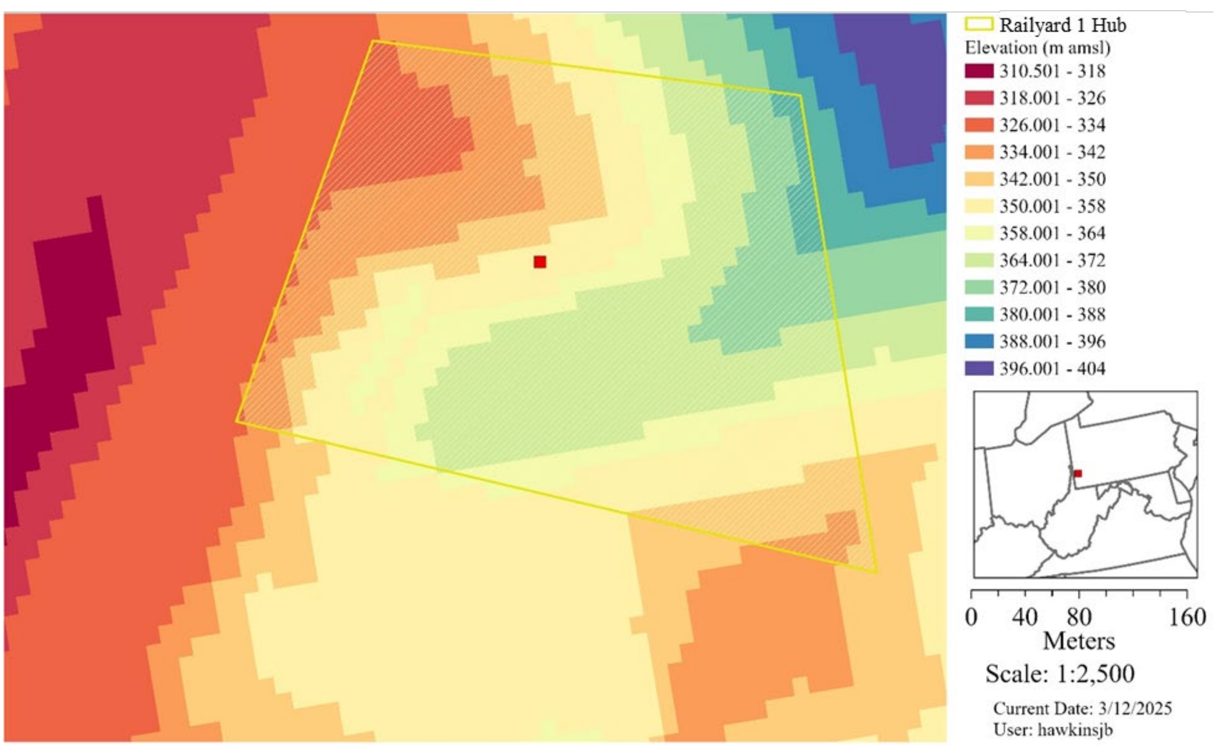

Figure 27. Elevation of the Railyard 1 Hub Area (United States Geological Survey [USGS], 2023).

Pressure: The facility will be at the ground surface and be subject to normal atmospheric pressure.

Temperature and Precipitation: The minimum, maximum, and average temperature and rainfall are shown, by month, for calendar years 2018 to 2024 in Figure 28. Temperatures ranged from -11 ºF to 95 ºF (average of 52.6 ºF). Monthly average rainfall ranged from 1.83 inches in July to 3.84 inches in February and totaled an average of 33.71 inches in the reviewed years.

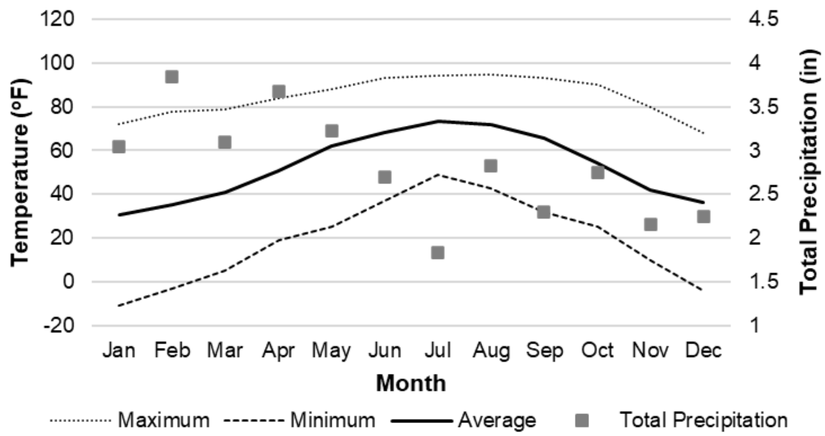

Figure 28. Average, maximum, and minimum temperature and total precipitation, by month, for calendar years 2018-2024 (National Oceanic and Atmospheric Administration [NOAA] Regional Climate Centers [RCCS], 2025).

Soil Conditions: The USDA has classified the soils in the area as silt loam and mine dumps with some sloping (Figure 29).

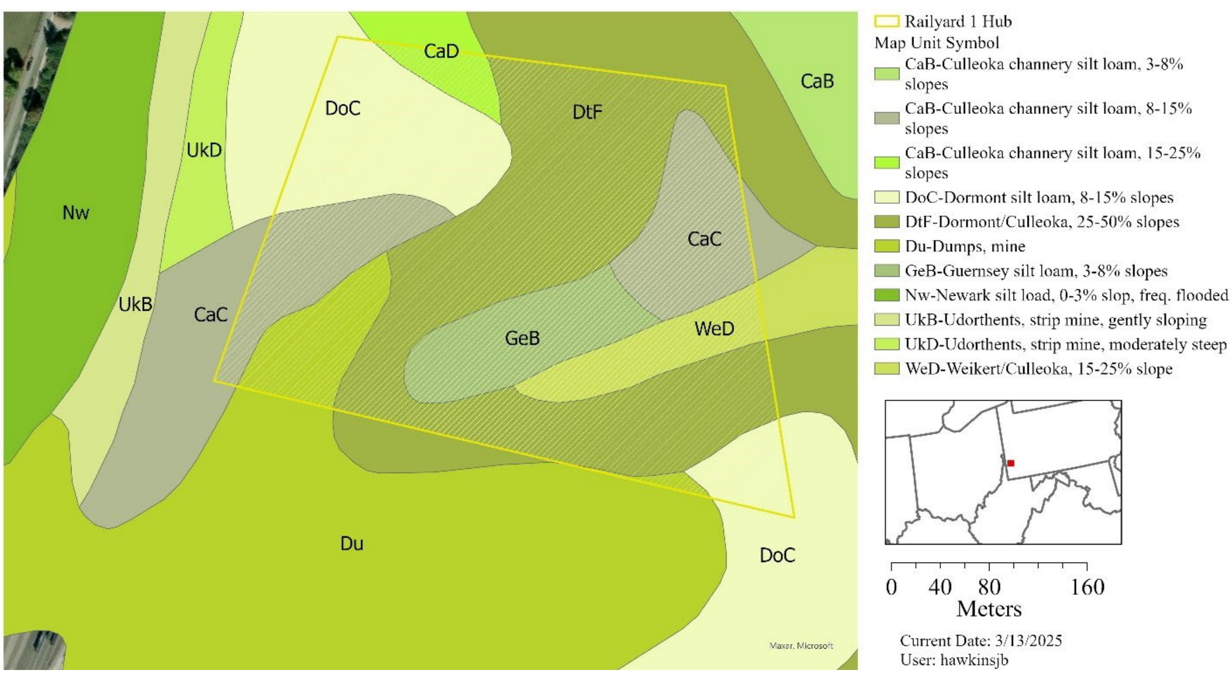

Figure 29. United States Department of Agriculture (USDA) soil analysis in the Railyard 1 Area (United States Department of Agriculture [USDA], 2024).

Seismic: The seismic risk in the project area is the lowest seismic risk according to the United States Geological Survey (USGS, 2022).

Corrosive Conditions: The corrosive conditions experienced by equipment in the Railyard 1 intermodal hub include external conditions and internal conditions. External conditions that impact corrosion are freeze/thaw, precipitation, earth movement, etc. (Sections 5.3 and 5.5). Internal conditions that impact the corrosion of the pipeline include trace components in the CO_2 stream, specifically water, oxygen, H_2S, and SO_2.

Current Land Use: The site is currently a deciduous forest (USGS, 2019). The adjacent site is an active railyard.

6.4 Capacity Specifications / Minimum Functional Objectives

Capacity specifications are controlled primarily by the pipe size and the maximum allowable operating pressure (MAOP) and the classification of the area. The pipeline is assumed to be constructed out of Schedule 80 pipe (Table 14). Capacity calculations have been calculated, according to Bernoulli's Principle, for each pipeline segment, assuming they operate at MAOP as well as accounting for average pressure loss.

Table 14. Schedule 80 pipe specifications, including the MAOP for different classification areas[(a)] (The Engineering ToolBox, 2003).

Pipe Size *(in)*	**Diameter *(in)***		**Nominal Thickness *(in)***	**Volume *(ft^3/ft)***	**Weight**		**No. of threads/in. of Screw**	**MAOP (psi)**			
	Ex-ternal	**In-ternal**			***lb/ft***	***kg/m***		***Class 1 0.72***	***Class 2 0.6***	***Class 3 0.5***	***Class 4 0.4***
4	4.5	3.83	0.34	0.08	14.9	22.17	8	3,808	3,173	2,644	2,116
6	6.63	5.76	0.43	0.181	28.6	42.56	8	3,269	2,724	2,270	1,816
8	8.63	7.63	0.5	0.3171	43.4	64.59	8	2,920	2,433	2,028	1,622
12	12.75	11.38	0.69	0.7058	88.6	131.85		2,728	2,273	1,894	1,515
16	16	14.31	0.84	1.117	137	203.88		2,646	2,205	1,838	1,470
24	24	21.56	1.22	2.536	297	441.99		2,562	2,135	1,779	1,423

Notes: a. Classification area design factors are found in 49 CFR §192.111. Area classifications are found in 45 CFR §192.5. Areas listed as High Population Areas are assumed to be Class 4 areas (preponderance of four-story or larger buildings for human occupancy). Areas listed as Other Populated Areas are assumed to be Class 3 areas (46 or more buildings for human occupancy per unit area or within 100 yards of defined outdoor area). All other areas are assumed to be Class 1 areas (less than 10 buildings per unit area for human occupancy).

6.5 Reliability and Maintainability

The Reliability and Maintainability is commented on for the Railyard 1 Hub Area. This includes the uptime targets, safety and compliance, and sustainability and environmental impact of the area. In addition, assumptions for uptime targets and the notes on the sustainability and environmental impact for the other nodes in the Conceptual Scenarios are detailed.

Uptime Targets: *Railyard 1 Hub Area uptime targets:* Annual planned maintenance for the system includes the following: patrolling (49 CFR §192.702), leakage surveys (49 CFR §192.706), required external corrosion control monitoring and remediation (49 CFR §192.465), repair requirements (49 CFR §192.711-720), and records retention (49 CFR §192.709). In addition, other component inspections and maintenance will be followed, such as pressure regulation devices, valves, vaults, and compressors. The cadence and impact of these activities on facility uptime targets will be defined in future phases of the project.

Conceptual scenarios uptime targets: The system has been designed assuming a 90% uptime for each node within the network. The flow into the Railyard 1 Hub Area is estimated assuming randomly assigned system should be able to downtime dates that are repeated quarterly. This simulates the expected variations of flow into the Railyard 1 Hub Node.

Safety and Compliance: *Pipeline design:* Pipeline designed will follow the requirements set forth in 49 CFR §192.101-205 and DNV (2010).

Valves: Block valves should be placed based on the area's legal requirements. Block valves can reduce volume of released product in containment failures, increase maintainability by allowing sectioning during depressurization. The effectiveness of these valves relies heavily on a robust leak detection system. Check valves can also be added to reduce volume of leaked CO_2 in the event of accidental release.

Vent stations: Vent stations generally should be pointing at a 45-degree angle away from the direction of highest consequence. Design of vent stations should take into account dominant wind and topography, and should be robust enough for worst case foreseeable CO_2 release and weather conditions.

Routing: Routes should be determined based upon population density according to ISO 13623. The route should be documented with respect to length of pipeline in each population density zone.

Stream composition: With a co-mingling system an analysis should be done to ensure that the mixing of different streams do not cause water-dropout, other intended chemical reactions, or other miscellaneous condensation. For shorter pipeline sections where sufficient de-watering cannot occur, polyethylene liners may be considered for corrosion control.

Federal, State, and Local Regulations: Required federal, state, and local regulations and permits have been defined in Section 3 of this report. RY1 Hub Area is in Washington County, Pennsylvania. Thus, identified permits for Washington County, the Commonwealth of Pennsylvania, and the United States apply.

6.6 Sustainability and Environmental Impact

To minimize the impact of the intermodal hub's construction and operation on the environment and optimize the net CO_2 transported and stored by the hub, a life cycle assessment (LCA) was completed for conceptual Scenarios 1 and 2. The analysis was performed using openLCA (version 2.4.1) software coupled with the ecoinvent (version 3.9.1) database and will quantify key impact categories such as climate change, water and land usage, and acidification to understand the sustainability and environmental impact of the hub. ReCiPe 2016 v 1.03 midpoint (H) was used as the impact assessment method, and inputs for the LCA model was generated by the pre-FEED study. Additionally, the hub's primary waste streams was identified in the pre-FEED study and reviewed to determine the appropriate regulatory response for compliance.

The LCA will also include a sensitivity analysis that compares sub-scenarios, such as using different materials of construction, electricity generation technologies, and transportation methods, to understand their effect on the overall LCA results. Primarily, however, the LCA was used to assess the intermodal hub's global warming potential (GWP) in terms of kilograms of CO_2-equivalents generated per kilogram of CO_2 transported/stored. This value was used to calculate the net CO_2 transported and stored by the hub, which will then be optimized by weighing different environmental impact and economic factors.

6.7 Economic Considerations

The economic assessment of the system is presented in Section 4 of this report.

6.8 Feed Stock Properties

Feed stock properties for power generation and CO_2 inlet properties are defined for the RY1 Hub Area below.

Power Generation: Power requirements will be satisfied by the local grid. Power requirements will be defined in later phases of the project. The site is located within the Allegheny Power Systems Zone of the PJM Interconnection (2023). Current (2024 annual) industrial power rates in Pennsylvania at 7.84 cents per kilowatt-hour (EIA, 2025c).

CO_2 Inlet: CO_2 will arrive at the RY1 Hub Rally Point from four different sources in both scenarios. These are outlined in Section 2. In both scenarios, the rally point will have to receive and store supercritical and liquefied CO_2 and transport via pipeline supercritical CO_2 to the storage area.

6.9 Products

Expected products are defined for the RY1 Hub Area. This includes the amount, state, and purity of the CO_2 resulting from the RY1 Hub Area.

6.10 Integration Requirements

Integration Requirements are considered for the RY1 Hub Area. These include system integration with existing utilities and offsite systems, quality assurance, and user requirements.

Quality Assurance: *Standards and procedures to ensure the quality of the design and construction:* Pipeline designs will follow the regulatory requirements detailed in 49 CFR §192 and the standards set forth by DNV (2010).

Includes testing protocols, certifications, and quality control measures: DNV (2010) sets for requirements for flow assurances:

- Modeling should be done to analyze the effect of temperature and pressure of the CO_2 on the flow capacity in the pipeline; care should also be taken to negate hydrate formations, which may cause blockages in flow.
- Models should also be developed to analyze water drop-out, pressure surges, controlled and accidental release, shut-in and start-up operations, depressurization and heat transfer to surroundings.
- Hydrate formation should be prevented to avoid the risk of blockages. Sufficient dewatering of the CO_2 stream should be done prior to transport and should be monitored and controlled.

User Requirements: *Considerations for the end-users of the system or product:* For the end-user to be able to use the transport network, the network must be 1) cost-effective, 2) applicable to the size of the user's CO_2 source, and 3) operational within a reasonable distance of the user's CO_2 source. These considerations will be further developed and defined as part of future tasks, particularly through the completion of the techno-economic assessment / BCA and LCA. Information obtained through these assessments will be used to understand the feasibility of integrating the transport network with various sizes and locations of CO_2 sources and to ensure applicability of the network to relevant sources in the area. Additionally, other user requirements for the transport network will be identified as applicable as the project progresses.

Accessibility: The system will establish a tariff rate at the RY1 Hub Receiving Area. This rate, along with terms and conditions, will be made publicly available to ensure transparency and accessibility to the transport network. Economic information obtained from the pre-FEED study and the techno-economic assessment / BCA, along with publicly available literature, will be used to establish the rate and its associated terms and conditions.

7.0 Conclusions

The project accomplished several key outcomes. The project success criteria from the Project Management Plan and how each were satisfied are provided in Table 15.

Table 15. Project Success Criteria, established at the outset of the project, and the outcome from the work.

Success criteria	Task	Outcome
Collect datasets, files, metadata, map for CO_2 sources, sinks, pipelines, land use factors for a hub storage system	2.0	The project team developed maps that show the sources, sinks, anchor points for the hub, transport modes, and sensitive areas as part of the *project basis of design* and *risk assessment*, completed in Months 7 and 11 of the project, respectively.
Verification that the project can be permitted	3.0	The project team developed a permitting plan for the transport hub that included the federal, state, and local permitting requirements. This plan identified the permitting authority, application requirements, fees, public comment period, and potential lead time. This was completed in Month 10 of the project.
Provide evidence that project is economically feasible	4.0	A cost assessment and BCA were completed for each of the Scenarios considered in the project. The BCA found the following: In a moderate-growth scenario, CO_2 capture and transport infrastructure would expand incrementally, with early projects relying on truck and rail to move captured CO_2 to nearby injection wells, particularly in areas with limited pipeline access. This approach allows for flexible deployment while minimizing upfront capital costs. In a high-growth scenario, driven by aggressive climate policy, carbon markets, and industrial decarbonization mandates, the region could see the rapid buildout of a shared CO_2 pipeline network, similar to the development of natural gas infrastructure in the early 2000s This was completed in Month 9 of the project.
Reduce project risks and uncertainties	5.0	The project team completed a qualitative risk assessment of severity and likelihood of major risks, assessed the impact to specific receptors along the pipeline route (Impact Assessment), and completed Bow-Tie Assessment for each transportation mode. This was completed in Month 11 of the project.
Community Benefits Plan and SCI activities to evaluate public acceptance and community engagement	6.0	This section is deemed voluntary based upon the MEMORANDUM FOR ALL DEPARTMENT OF ENERGY ASSISTANCE AWARD with the Subject: Recission of the January 28th, 2025, Memorandum from the Department of Energy received on 3/14/25 by Battelle Memorial Institute.

In addition, the project team completed the following:

- Finish pre-FEED Design Product for RY1 Hub Area, including a basis of design (Sections 2.3 and 6.0), permitting plan (Section 3.0), economics assessment (Section 4.0), and risk assessment (Section 5.0).
- Complete process for temporal changes and regional interconnection, including modeling the impact of an expansion of the network to a hydrogen plant (Section 2.2) and demonstrating the addition of other existing sources and potential future sources (Section 2.4).
- Informed and briefed funding partners CNX, EQT, and Hope Gas through regular briefings and/or sharing of project deliverables.

- Linked our results to other DOE federal investments like the ARCH2 Hub, carbon storage projects, and other transport projects (See Section 2.4).

The project is well-positioned to continue to the FEED stage. Specific activities to be completed in the FEED study include the following:

- Identification and outreach to sources that are planning CO_2 capture projects as well as rail and trucking companies in the study area to supplement the interest and expertise of the funding partners for this project.
- Refinement of concepts and definition of specific equipment, piping, and construction requirements for the RY Hub 1 Area, including the development of process flow diagrams and instrumentation diagrams, layout drawings, and equipment specifications for the hub area.
- Outreach to regulatory and permitting entities to ensure compliance with permitting requirements and help establish relationships and expectations that would help facilitate permit processing.
- Refinement of project cost estimates using refined FEED study documentation and planning to obtain vendor quotes.
- Refinement of HAZID and ES&H requirements through plume release modeling; conversations with local emergency management leaders; and mitigation, recovery, and contingency planning.

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Appendix 1. Permitting/Regulatory Plan Analysis

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Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION)

Permitting/Regulatory Plan Analysis

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6/30/2025

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List of Acronyms

AOR	Area of Review
AST	Above-ground Storage Tank
BGEPA	Bald and Golden Eagle Protection Act
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAP	Corrective Action Plan
CCS	Carbon Capture and Sequestration
CE	Categorical Exclusion
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CWA	Clean Water Act
DEP	Department of Environmental Protection (Pennsylvania)
DOT	Department of Transportation
EA	Environmental Assessment
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ESA	Endangered Species Act
ESCGP	Erosion and sediment Control General Permit
FEED	Front End Engineering Design
FMCSA	Federal Motor Carrier Safety Administration
FRA	Federal Railroad Administration
GHG	Green House Gas
GP	General Permit
HAP	Hazardous Air Pollutant
HMR	Hazardous Materials Regulations
HOP	Highway Occupancy Permit
IP	Individual Permit
JPA	Joint Permit Application
MBTA	Migratory Bird Treaty Act
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review
NWP	Nationwide Permit
OAC	Ohio Administrative Code
ODNR	Ohio Department of National Resources
ODOT	Ohio Department of Transportation
OHWM	Ordinary High-Water Mark
OPSB	Ohio Power Siting Board
OSHA	Occupational Safety and Health Administration
OHSPO	Ohio State Historic Preservation Office
PA DCNR	Pennsylvania Department of Conservation and Natural Resources
PA DEP	Pennsylvania Department of Environmental Protection
PA SHPO	Pennsylvania State Historic Preservation Office
PCN	Pre-construction Notification
PENNDOT	Pennsylvania Department of Transportation
PFBC	Pennsylvania Fish and Boat Commission
PGC	Pennsylvania Game Commission
PHMC	Pennsylvania Historical and Museum Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration

PNDI	Pennsylvania Natural Diversity Inventory
PISC	Post-Injection Site Care
PSC	Public Service Commission (West Virginia)
PSD	Prevention of Significant Determination
PTE	Potential to Emit
PTIO	Permit-to-Install and Operate
PUC	Public Utility Commission (Pennsylvania)
PUCO	Public Utilities Commission of Ohio
ROW	Right-of-Way
RTE	Rare, Threatened, and Endangered
SDWA	Safe Drinking Water Act
SLAA	Submerged Land License Agreement
STB	Surface Transportation Board
SWPPP	Storm Water Pollution Protection Plan
SWQC	State Water Quality Certification
TMDL	Total Maximum Daily Load
TPY	Ton Per Year
UIC	Underground Injection Control
URS	Unified Registration System
USACE	United States Army Corps of Engineers
USDOT	United States Department of Transportation
USFWS	United States Fish and Wildlife Service
WIP	Watershed implementation Plan
WMA	Wildlife Management Area
WOTUS	Waters of the U.S.
WPCA	Water Pollution Control Act (West Virginia)
WQC	Water Quality Certification
WVDEP	West Virginia Department of Environmental Protection
WVDNR	West Virginia Division of Natural Resources
WVDOT	West Virginia Department of Transportation
WVHPO	West Virginia Historic Preservation Office

Executive Summary

The Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) project seeks to develop a pre-Front End Engineering Design (pre-FEED) of an intermodal transport hub in the Appalachian region comprising locations in Ohio, Pennsylvania, and West Virginia. The development of a CO_2 transportation and storage network, encompassing pipelines, rail, truck, and underground injection, requires navigating a complex landscape of federal, state, and local permitting requirements and regulatory approvals. Understanding and addressing these requirements early in project planning is critical to ensuring compliance, minimizing delays, and supporting safe, environmentally responsible operations.

Many permits and regulations need to be considered for successful construction and operation of the studied intermodal hub. The largest considerations of these are evaluating the environmental impacts of the conceptual intermodal CO_2 transport network. Underground storage of CO_2, particularly in deep geologic formations, is regulated by the U.S. Environmental Protection Agency (U.S. EPA) under the Underground Injection Control (UIC) program, specifically for Class VI wells and states can apply for permitting primacy from EPA when their regulations align with EPA requirements CO_2 injection well permit (i.e., a Class VI well permit) applicants must provide comprehensive site characterization, well design, monitoring, and post-injection care plans to ensure protection of drinking water sources. If a pipeline crosses federal land or waters, a National Environmental Policy Act (NEPA) review is required, necessitating environmental impact assessments and public engagement. Note however that NEPA review is not required for a Class VI well permit. Additionally, the U.S. Army Corps of Engineers (USACE) issues Section 404 and Section 10 permits for water crossings, that require detailed site plans, impact analyses, and mitigation strategies.

State and local agencies also have permitting and notification requirements that have to be satisfied before these types of facilities can be operated. While state permits typically require less public comment periods and require less time to process, there are situations where the state and local entities assume authority for federal regulations and must be as strict. In Ohio, the Department of Natural Resources (ODNR) oversees oil and gas activities and injection wells, while the Public Utilities Commission (PUCO) and Department of Transportation (ODOT) regulate pipeline and hazardous material transport. The Pennsylvania Department of Environmental Protection (DEP) and Public Utility Commission (PUC) play similar roles, with the Department of Transportation (PennDOT) overseeing truck and rail. In West Virginia, the Department of Environmental Protection (WVDEP), Public Service Commission (PSC), and Department of Transportation (WVDOT) share these responsibilities. For Class VI storage wells, the U.S. EPA remains the permitting authority in Pennsylvania while West Virginia and Ohio has recently been granted primacy for Class VI well permitting by EPA.

CO_2 transportation and storage projects must address a range of federal and state permitting requirements, each demanding detailed technical, safety, and environmental information. Early engagement with regulatory agencies and a comprehensive permitting strategy is essential for project success, regulatory compliance, and risk management. The permitting strategy will be expanded as more project information becomes available, such as defining any local requirements as the infrastructure and potential pipeline route is finalized.

1. Introduction

The Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) project seeks to develop the pre-Front End Engineering Design (pre-FEED) of an intermodal transport hub. The objectives of the conceptual project are to design, engineer and develop an efficient and economic transport network to transport CO_2, using multimodal methods, from sources of CO_2 to sinks of CO_2 in the tristate region of Ohio, Pennsylvania, and West Virginia. In this effort, the regional infrastructure of roads, rail and river transportation methods are considered along with the construction of new infrastructure. The potential site location is shown in Figure 1 along with the conceptual infrastructure and potential location storage and other CO_2 transportation.

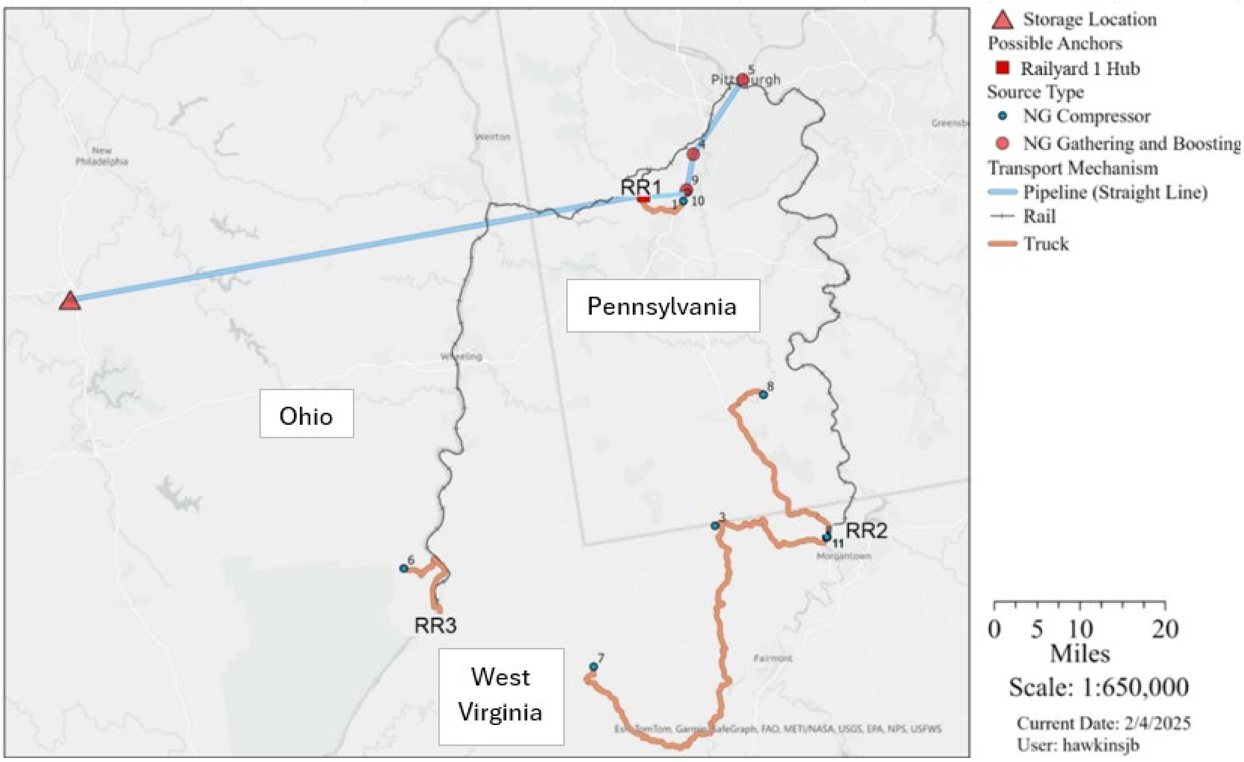

Figure 1: Conceptual Site Location and Development of the Intermodal Transport Hub from existing sources of CO_2 in Ohio, Pennsylvania, and West Virginia.

The development and operation of a CO_2 transportation hub that integrates truck, rail, and pipeline modalities is a complex undertaking that intersects with a wide array of regulatory requirements. Each transportation mode is governed by distinct federal, state, and local regulations, and the permitting landscape can vary significantly depending on the jurisdiction, the nature of the CO_2 being transported, and the specific operational activities involved. Successfully navigating this regulatory environment is critical to ensuring legal compliance, minimizing project delays, ensuring investor security, and safeguarding public health and the environment.

A permitting matrix serves as an essential tool for project developers, regulatory specialists, and stakeholders by providing a clear, organized overview of all required permits and approvals. By systematically mapping out the permitting requirements for each transportation mode—truck, rail, and pipeline—the matrix helps identify potential regulatory overlaps, gaps, and critical path items that could impact project timelines. This structured approach not only streamlines the permitting process but also enhances communication among project teams, regulatory agencies, and community stakeholders, ultimately supporting the successful and timely development of a multimodal CO_2 transportation hub.

Appendices A and B provide federal and state permitting matrices. Each matrix provides information about agencies, permitting requirements, application requirements, typical processing times, and public involvement requirements.

2. Regulatory Framework Overview

2.1. Federal

The storage of carbon dioxide (CO_2), particularly in deep underground geological formations, is primarily regulated at the federal level by the United States Environmental Protection Agency (U.S. EPA) through its Underground Injection Control (UIC) program. The EPA's authority stems from the Safe Drinking Water Act, and it specifically oversees Class VI injection wells, which are designed for the long-term storage of CO_2 as part of carbon capture and sequestration (CCS) projects. The U.S. EPA sets stringent requirements for site characterization, well construction, operation, monitoring, and post-injection site care to ensure the protection of underground sources of drinking water and to minimize the risk of CO_2 migration or leakage.

The transportation of CO_2 across the United States is subject to oversight by several federal regulatory agencies, each with jurisdiction over specific modes of transport. For CO_2 pipelines, the primary federal authority is the Pipeline and Hazardous Materials Safety Administration (PHMSA), a division of the U.S. Department of Transportation (DOT). PHMSA is responsible for developing and enforcing regulations related to the safe design, construction, operation, and maintenance of CO_2 pipelines under the federal Pipeline Safety Act. In addition, the U.S. EPA may be involved when federal funding or federally own land is involved, in reviewing environmental impacts under the National Environmental Policy Act (NEPA) and ensuring compliance with the Clean Air Act and Clean Water Act.

For CO_2 transportation by rail, the Federal Railroad Administration (FRA), also under the DOT, establishes and enforces safety standards for rail operations, including the transport of hazardous materials such as compressed or liquefied CO_2. The Surface Transportation Board (STB) also plays a role in economic regulation and oversight of rail carriers. When CO_2 is transported by truck, the Federal Motor Carrier Safety Administration (FMCSA), another DOT agency, regulates the safety of commercial motor vehicles and drivers, while PHMSA sets requirements for the packaging, labeling, and handling of hazardous materials during highway transport. Across all modes, the U.S. EPA may require environmental reviews or permits, and the Occupational Safety and Health Administration (OSHA) sets standards to protect worker safety during loading, unloading, and handling operations. Together, these agencies form a comprehensive regulatory framework to ensure the safe and environmentally responsible transportation of CO_2 throughout the country.

2.2. State

In Ohio, the primary agency overseeing CO_2 storage and transportation is the Ohio Department of Natural Resources (ODNR), specifically through its Division of Oil and Gas Resources Management. ODNR is responsible for permitting and regulating underground injection wells, including those used for CO_2 sequestration, under the state's authority and in coordination with the U.S. EPA. At the time of this regulatory evaluation, Ohio is not a primacy state for Class VI wells, though they are seeking primacy from the US EPA for CO_2 storage wells. Currently ODNR plays a significant role in site assessment, monitoring, and enforcement for other classes of injection wells. For CO_2 transportation, the Public Utilities Commission of Ohio (PUCO) regulates intrastate pipeline safety, while the Ohio Department of Transportation (ODOT) oversees the movement of hazardous materials by truck and rail within the state.

In Pennsylvania, the Department of Environmental Protection (PA DEP) is the lead agency for environmental permitting; however, EPA has primacy for all UIC well activities in Pennsylvania. PA DEP is involved in site reviews, environmental impact assessments, and ongoing monitoring. The Pennsylvania Public Utility Commission (PUC) regulates intrastate pipeline safety, and the Pennsylvania Department of Transportation (PennDOT) oversees the safe transport of hazardous materials by truck and rail. Coordination between these agencies ensures that CO_2 transportation and storage projects comply with both state and federal requirements.

In West Virginia, the Department of Environmental Protection (WVDEP), through its Office of Oil and Gas, is the lead agency responsible for permitting and regulating underground injection wells, including those used for CO_2 storage Ohio was recently granted primacy for Class VI well permitting and the program is administered by WVDEP). The West Virginia Public Service Commission (PSC) regulates intrastate pipeline safety, while the West Virginia Department of Transportation (WVDOT) manages the permitting and oversight of hazardous materials transported by truck and rail. These agencies work together to ensure that CO_2 storage and transportation activities are conducted safely and in accordance with state and federal laws.

3. Permitting Review

A high-level review of the required permits is summarized in this section, however the full details of the federal and state permits and regulations required are summarized in Tables 1-5, which are provided in Appendices A and B. The permits summarized are those that require the most time or information needed to complete.

3.1. UIC Class VI Permitting

A significant permit needed for this type of intermodal hub is approval to properly sequester the CO_2 transported to the selected storage location. Five required permit plans must be developed as part of the (UIC) Class VI requirements (40 CFR §146) and submitted with the permit applications: testing and monitoring plan, the post-injection site care (PISC) and closure plan, the Corrective Action Plan (CAP), the emergency and remedial response plan, and the well plugging plan. The permit application also covers the pre-operation formation testing program, stimulation program, procedure to conduct injection operations, schematics of well(s), (area of review) AoR and financial responsibility. This process can typically take 24-36 months and includes a public comment period.

3.2. Federal CO_2 Pipeline Transportation

Pipeline Safety and Siting Approvals (PHMSA/DOT): Pipeline operators must demonstrate compliance with PHMSA's safety regulations for the design, construction, operation, and maintenance of CO_2 pipelines (49 CFR Part 195). This involves submitting detailed engineering plans, route maps, material specifications, safety and emergency response plans, and operational procedures. Operators must also provide information on integrity management, risk assessments, and public awareness programs. While PHMSA does not issue a single “pipeline permit,” operators must register and may be subject to inspections and audits to verify compliance. Also, special permits are required to satisfy Federal pipeline safety regulations, as shown in Appendix A and B. It should be noted that PHMSA proposed CO_2 pipeline safety regulations in January 2025 that were rescinded by Presidential Executive Order. Industry insiders anticipate that these regulations will be slightly modified and re-proposed.

Environmental Review (NEPA): If the pipeline project involves federal land, federal funding, or requires a federal permit, a NEPA review is triggered. To complete this process, applicants must submit a project description, alternatives analysis, environmental impact assessments (covering air, water, wildlife, cultural resources, and socioeconomics), and proposed mitigation measures. Public involvement and interagency coordination are also required, and the process may result in an Environmental Assessment (EA) or a more detailed Environmental Impact Statement (EIS). This very intensive process systematically collects baseline information and predicts how the project construction and operations will impact the potential site location.

3.3. Federal CO_2 Rail Transportation

Hazardous Materials Transportation Approval (PHMSA/DOT): To transport CO_2 by rail, shippers must comply with PHMSA’s Hazardous Materials Regulations (HMR) (49 CFR Parts 171-180). This requires providing information on the physical and chemical properties of the CO_2, proper classification, packaging and container specifications, labeling, placarding, shipping papers, and emergency response information. Training records for personnel handling hazardous materials must also be maintained.

Rail Safety Standards (FRA/DOT): Rail carriers must comply with FRA safety standards, which include requirements for railcar design and maintenance, track integrity, operational procedures, and employee training. Documentation needed includes equipment inspection and maintenance records, safety management plans, and evidence of compliance with operational and safety protocols. There is also a new rule that went into effect in January 2025 that amends the HMR to require railroads that carry hazardous materials to generate electronic form, maintain, and provide certain info regarding hazardous materials in rail transportation to enhance emergency response and investigative effort

Surface Transportation Board (STB) Approvals: If new rail lines are constructed or significant modifications are made, STB approval is required. Applicants must submit detailed project descriptions, route maps, engineering plans, and environmental documentation (often prepared under NEPA). The application must also address land acquisition, community impacts, and proposed mitigation measures.

3.4. Federal CO_2 Truck Transportation

Hazardous Materials Transportation Approval (PHMSA/DOT): Transporting CO_2 by truck requires compliance with PHMSA’s hazardous materials regulations, including proper classification, packaging, labeling, placarding, and shipping documentation. Applicants must provide information on the CO_2 properties, container specifications, emergency response procedures, and training records for drivers and handlers.

Motor Carrier Safety (FMCSA/DOT): Commercial carriers must comply with FMCSA safety regulations, which include requirements for driver qualifications, vehicle maintenance, hours of service, and safety management practices. The information needed includes driver licensing and training records, vehicle inspection and maintenance logs, and safety policies and procedures.

3.5. State CO_2 Transportation

The majority of state permits are simpler and are less likely to require public comment periods. Additionally, the time needed to apply for the permits is typically shorter than that required for federal permits. Pipeline permits are still the most complex as they have a larger impact on the surrounding region compared to rail and truck, which will utilize existing infrastructure.

4. Conclusions and Path Forward

The permits and processes required for this conceptual intermodal facility are consistent with previously studied CCS projects. Federal requirements, such as the application for a Class VI well permit or developing an EIS through NEPA, can require a large amount of time and effort. These can take over two years in some cases to complete the required information and apply for appropriate approvals.

Most of the permits that are needed for construction are routine permits that require a little time for preparation and a modest application fee. They are also generally approved within a few weeks or months. Potential issues with permitting requirements could come from public comments or public opposition to the permit. In particular, the sitting of pipelines could possibly prove to be a time-consuming permitting process if formal objections are made to project plans. Permitting generally takes at least one month for approval (with a public comment period) if no comments are received. With comments, however, the process can take up to 12 months. Water quality permits, air quality permits, wetlands permits, and endangered species act permits also have a public comment period and/or iteration with regulators that could potentially delay the project. These permit applications need to be started at the project outset. Application fees are not exorbitant, but public engagement costs to avoid public protests and rejection will be a significant expense.

This permitting matrix will be further updated once the final pipeline route is completed, which will allow for a more detailed summary of the local permits and right-of-way information. Additionally, the estimated labor cost of the permits as well as the applications fees will be included.

Appendix A: Federal Permit Tables

Table 1: Overview of Federal Permitting and Regulations for Pipeline, Rail, and Truck

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	Requirements	Potential Studies & Application Considerations	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline	United States Environmental Protection Agency (USEPA)	Prevention of Significance Determination (PSD) Clean Air Act (CAA) - 40 CFR Part 52.21	Required for new major sources or major modifications at existing sources for air pollutants where the area source is in attainment or unclassified National Ambient Air Quality Standards (NAAQS)	Emissions limits study: Determine the new source of potential to emit (PTE) in tons per year (TPY) for CO_2 considering enforceable limits. If potential emissions equal to or greater that 75,000 TPY, PSD permit need to be applied	10 - 12 months	Yes, as a part of the New Source Review (NSR) permitting process, this includes specific public notice requirements and public comment period prior to USEPA take final action	30 days
		Title V Permit Compliance Assurance Monitoring (CAM) Rule – 40 CFR part 64	This permit required for CO_2 pipelines as they are considered major stationary sources of air pollution under CAA	USEPA's Green House Gas (GHG) Tailoring Rule establishes thresholds for Title V permitting based on CO_2 equivalent emissions.	45 - 60 days	Yes, public involvement is required to approve Title V permit. The public need to participate in the process, including commenting on draft permits and requesting public hearing when required. Public can petition the USEPA to object a Title V permit.	30 days
		Class VI Well Permit Safe Drinking Water Act (SDWA)	When transporting CO_2 for the purpose of geologic sequestration under the EPA's Underground Injection Control (UIC) program	Characterize the geologic setting of the proposed GS site to demonstrate that the Class VI well will be sited in an area with a suitable geologic system, consisting of an injection zone with sufficient capacity to receive the CO_2 and a confining zone that is free of transmissive faults or fractures	24 - 36 months	Yes. According to EPA's Under Ground Injection Control (UIC) Class VI Program, public involvement is mandatory and includes public notification, public comments, and potential public hearing before approval of the permit application	30 days
	United States Department of Transportation (USDOT) - Pipelines and Hazardous Materials Safety Administration (PHMSA)	Pipelines Special Permits PHMSA - 49 CFR 190.341	Need for a waiver or modification of a regulatory requirement, ensuring equivalent or greater safety	Analyze conditions grants on alternative measures that maintain or improve safe CO_2 transportation	90 days	Yes. The process includes publishing notices of special pipeline permits in the Federal Register to solicit public comments.	30 days

Table 1 (continued): Overview of Federal Permitting and Regulations for Pipeline, Rail, and Truck

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	Requirements	Potential Studies & Application Considerations	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Railroad	United States Department of Transportation (USDOT) - Pipelines and Hazardous Materials Safety Administration (PHMSA)	DOT-SP20936 Hazardous Materials Regulations (HMR) - 49 CFR Parts 106, 107, and 171-180	When transporting carbon dioxide in specific types of cylinders (i.e., DOT 3AL, TC/3ALM, and UN ISO 7866)	Safety control measures including prescribed packaging and details of operational control need to be included.	90 days	DOT-SP 20936 permit does not require specific formal public involvement. However, the permit must be consistent with the public interest and the project should not pose risks on safety or the environment.	N/A
		PHMSA Special Permits Hazardous Materials Regulations (HMR) - 49 CFR Parts 106, 107, and 171-180	When there is a requirement for alternative method of transport under unique conditions to prevent full compliance with HMR, a need for alternative safeguards that can offer a greater level of safety, or/and innovation in transportation methods that require a deviation from HMR (e.g., innovation in packaging or loading methods, new tank car designs)	N/A	90 - 180 days	Yes. Process includes publishing notices of special pipeline permits in the Federal Register to solicit public comments.	30 days
Trucks	United States Department of Transportation (USDOT) - Federal Motor Carrier Safety Administration (FMCA)	Hazardous Materials Safety Permit Federal Motor Carrier Safety Administration (FMCSA) Regulations - 49 CFR § 385 Subpart E.	When transporting CO_2 in bulk quantities exceeding certain limits, or the transported CO_2 is in certain configurations such as refrigerated liquified CO_2.	First time HMSP applicants must file the new Unified Registration System (URS) MCSA-1 form with FMCSA before conducting operations in commerce that require a safety permit. Submit proof of required insurance using the DOT MCS-90 form and submit a current Pipeline and Hazardous Materials Safety Administration's Registration	120 days	The primary responsibility of issuing and enforcing HMSP lies with FMCSA. The public has minimal direct involvement in the approval process, which focuses on reporting incidents or participating in public comment during proposing or amending specific regulations.	N/A

Table 2: Federal Permits and Regulations for All Forms of CO_2 Transportation

Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
United States Army Corps of Engineers (USACE)	Clean Water Act (CWA) Section 404; Nationwide Permit (NWP) or Individual Permit (IP) [to be confirmed with aquatic resource survey]	Before commencing activities required for the construction, maintenance, repair, and removal of any utilities or facilities in Waters of the U.S. (WOTUS), provided that a single and complete project does not result in the loss of greater than one-half acre of WOTUS. Pre-construction notification (PCN) is required for any activity for impacts to WOTUS of more than one-tenth of an acre.	Wetland and stream delineation; Completed PCN Form and supporting narrative, engineering drawings and wetland/waterway impact figures; Potential mitigation	6-9 months for NWP; 24 months for IP If other USACE permits are needed, this review can be conducted concurrently with Section 10 and Section 408.	Yes. US Army Corps of Engineers are responsible for preparing public notices to solicit public comments and then evaluating impacts and public comments. They may require modifications to the project in order to ensure minimal adverse effects.	30 days
	Section 10 Permit Rivers and Harbors Act	Required for work or structures in, over, or under navigable waters of the United States	Field Delineation to identify WOTUS potentially being impacted by the Project	2-4 months Review can be conducted concurrently with Section 404 and Section 408.	Yes. US Army Corps of Engineers are responsible for preparing public notices to solicit public comments and then evaluating impacts and public comments.	30 days
	Section 408 Permit Code 33 U.S.C 408	Required for any CO_2 transportation project that involves navigation channel or activities above and below the ordinary high-water mark (OHWM)	N/A	9-12 months	Yes. US Army Corps of Engineers are responsible for preparing public notices to solicit public comments and then evaluating impacts and public comments.	30 days
United States Fish and Wildlife Service (USFWS)	Endangered Species Act (ESA) Section 7	When an activity may affect federally listed rare, threatened and endangered species (RTE) and critical habitats. Preliminary screening of the Study Area on the USFWS IPaC system will indicate potential RTE species in the vicinity of the Study Area. Formal consultation letters to USFWS are likely required.	USFWS IPaC Screening; consultation with USFWS; Habitat assessment; Biological assessment of potential impacts; Species-specific surveys	60 days	No public engagement required	N/A
	Migratory Bird Treaty Act (MBTA) and Bald and Golden Eagle Protection Act (BGEPA) Compliance	When construction or operation of a proposed facility could impact bald or golden eagles or migratory birds (including tree clearing activities)	Habitat assessment; Avian nest surveys (if requested by agency)	30 to 45 days for each consultation submittal, runs concurrent with USACE	No public engagement required	N/A

Table 2 (continued): Federal Permits and Regulations for All Forms of CO_2 Transportation

Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
National Environmental Policy Act (NEPA)	Environmental Impact Statement (EIS), Environmental Assessment (EA), or a Categorical Exclusion (CE) Determination.	Required prior to funding (through Department of Energy), authorizing, or implementing an action, federal agencies must consider the effects the proposed action may have on the environment and the related social and economic effects	Environmental Considerations (e.g. Cultural Resources, Streams and Wetlands)	6 months - 3 years	Yes. NEPA requires public engagement and the process includes involving the public in decision-making process.	30 days

Appendix B: State Permit Tables

Table 3: State of Ohio Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines	Ohio Environmental Protection Agency (OEPA)	Stormwater General Permit for Construction Activities CWA (Clean Water Act)	Discharge of stormwater from construction impacting 1 acre or more	Stormwater pollution prevention plan (SWPPP) - Construction	45 days	Yes. Storm Water General Permit for Construction Activities requires public involvement and participation	30-60 days
		Section 401 Water Quality Certification or Director's Authorization CWA/Section 104	When the Project involves fill in WOTUS over 1/2 acre, project cannot meet Regional and/or Special Conditions of NWP XX, -would increase permanent, above-grade fill within the 100-year floodplain (including the floodway and the flood fringe), and/or stream impacts in OEPA ineligible areas.	Associated with a USACE Section 404 permit unless authorized by Director of OEPA	90 days - 1 year	Yes. Public engagement is required for Section 401 Water quality Certification and Director's Authorization processes. Public engagement requirements depend on if a specific project has significate public interest.	30 days
		Isolated Wetland Permit CWA/Ohio Revised Code (ORC) sections 6111.02	Anyone who wishes to discharge dredged or fill material into isolated wetlands in Ohio must obtain an Isolated Wetland Permit from OEPA.	Jurisdictional determination: Details on impacts and mitigation proposed	6 months	Yes. Public engagement is required specifically if the project impact a Category 3 isolated wetland	20 days
		General Permit for Discharges of Non-Contact Cooling Water *(If pipeline operations involve cooling water discharge to the water of the U.S.)* Ohio Revised Code Chapter 6111	Required when discharging waters that remove heat from industrial processes at industrial facilities.	Water quality studies	180 days	Yes. Public engagement is required	30 days
		General Permit for Discharges of Hydrostatic Test Water Ohio Revised Code Chapter 6111	Required when discharging hydrostatic test water to waters of the State from water mains, pipelines, tanks, and other vessels (new/unused or used) and raised to greater than	May require additional surface water and/or municipal water source permitting.	45 days	Yes. Public engagement is required	30 days

Table 3 (continued): State of Ohio Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)			atmospheric pressure in order to check for leaks and/or structural integrity of these facilities.				
		National Pollutant Discharge Elimination System Permit for Direct Discharge Ohio Revised Code Chapter 6111	Required when discharging to a receiving stream.	Discharge volumes and pollutant concentrations, anti-degradation studies.	180 days	Yes. Public engagement is required	30 days
		Permit-to-Install and Operate (PTIO) Air Emission Sources Ohio Administrative Code (OAC) 3745-31-05	Prior to installation of any new air contaminants emissions unit or modification of an existing one to regulates stationary sources of criteria or hazardous air pollutants.	Sitewide emission inventory to include all stationery and fugitive emission sources	18 months	PTIO requires public engagement only if the permit establishes federally enforceable terms and conditions or has significant public interest.	30 days (if required)
	Ohio Department of Natural Resources (ODNR) Division of Wildlife	Environmental Review Request; In-Water Work Waiver NEPA	Activities that could affect state protected animal and plant species. Any work associated with a regulated activity under a NWP cannot take place during the restricted period per the ODNR, Division of Wildlife (DOW) In-Water Work Restrictions, unless the applicant receives advanced written approval from the DOW.	Complete and submit the ODNR Natural Heritage Data Request form including project information and results of surface water delineation to determine affected species, if any. ODNR DOW provides a list of endangered and threatened species. ODNR Division of Natural Areas & Preserves provides a list of rare plant species. In-Water Work Waiver Request will require wetland and waterways delineation and details on impacts.	30-45 days	Environmental Review Request, In-Water Work Waiver required public engagement depending on the potential impacts of the project.	N/A
	Ohio Department of Natural Resources (ODNR) - Division of Forestry (24 State Forests in OH)	Special Use Permit Chapter 1501:3 of the Ohio Administrative Code - Rule 1501:3-2-13	Required for the approved use on State Forest property.	Requires consultation with State Forester to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural surveys, wetland/waterbody delineation, and Ohio Natural Heritage Inventory database review.	30 days	Public engagement is not required	N/A
	Ohio Department of Natural Resources (ODNR) - Ohio State Parks (76	Special Use Permit Ohio Administrative Code Chapter 1501:46	Required for the approved use on State Park property.	Requires consultation with the State Park to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural	45-60 days	Public engagement is not required	N/A

Table 3 (continued): State of Ohio Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)	State Parks in OH)			surveys, wetland/waterbody delineation, and Ohio Natural Heritage Inventory database review.			
	Ohio Department of Natural Resources (ODNR) - Division of Water Resources	Water Withdrawal Registration Ohio Revised Code Section 1521.16 and Section 1521.23	Projects requiring any owner of a facility, or combination of facilities, with the capacity/need to withdraw water at a quantity greater than 100,000 gallons per day to register such facilities with the ODNR Division of Water Resources.	Ownership information, water use estimates, withdrawal capacity, supply sources, location, etc.	45-60 days	Public engagement is not required	N/A
	Ohio Department of Natural Resources (ODNR) - Division of Oil and Gas Resources Management	Application for a Permit (Form 1) Chapter 1509 of the Ohio Revised Code (ORC) and Chapter 1501:9 of the Ohio Administrative Code (OAC)	Required to drill, reopen, deepen, plug back or convert well. It is required for obtaining PTIO and PTI.	Application (including well information, geological formation and depth, royalty interest owners, well construction specs, etc.), Ohio registered surveyor plat(s), Restoration Plan, Well Completion Report (Form 8), and fees.	30 days	Public engagement is required	30 days
	Ohio State Historic Preservation Office (SHPO)	National Historic Preservation Act, Section 106 Clearance NHPA Section 106	Activities that could potentially affect archeological, cultural, or historical resources	Desktop cultural resources review; archeological surveys and cultural resources survey and visual resources assessment (if requested by the agency); data recovery if eligible cultural sites are found; working with the SHPO/THPO office to resolve adverse effects; subsequent consultation. Request for Concurrence from the OH SHPO	30-60 days	Yes. Public engagement and tribal consultation is required.	30 days
	Ohio Department of Transportation (ODOT)	Driveway Access Permit - Construction and Operations Ohio Revced Code - Section 5501.31 and Section 5515.01	Required for driveway access from state highway right-of-way.	Plans, details, drawing.	30 days	No public engagement required	N/A
		Utility Access Permit - Construction and Operations Ohio Revised Code Sections 5515.01 and 5515.02	Required for utility installation on controlled access facilities	Plans, details, drawing.	30 days	Yes. Public engagement and tribal consultation are required.	30 days

Table 3 (continued): State of Ohio Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)	Public Utilities Commission of Ohio (PUCO) – Ohio Power Siting Board (OPSB)	Certificate Application for Gas Pipelines Ohio Administrative Code Chapter 4906-4 and Section 4906.06 of the Ohio Revised Code	Required for a gas pipeline that is greater than five hundred feet in length, and its associated facilities, is more than nine inches in outside diameter and is designed for transporting gas at a maximum allowable operating pressure in excess of one hundred twenty-five pounds per square inch. If the pipeline provides energy for a specific customer, a Letter of Notification can be used at any distance.	Abbreviated Certificate Application (Letter of Notification or Construction Notice) or Standard Certificate Application (Dependent upon pipeline length and location). Studies include alternative analysis, air permitting, archeological and history/architectural surveys, geotechnical surveys, noise analysis, public engagement, visual analysis, environmental studies and coordination with public agencies, stormwater permitting, floodplain coordination and permitting, and road and transportation analysis.	30 days	Yes. Public engagement and tribal consultation is required.	30 days
	PUCO – OPSB	Certificate Application for Electric Transmission Facilities Ohio Administrative Code Chapter 4906-4 and Chapter 4906-5	Required for electric transmission line and associated facilities of a design capacity of one hundred kV or more.	Abbreviated Certificate Application (Letter of Notification or Construction Notice) or Standard Certificate Application (Dependent upon electric transmission line length and location). Studies include alternative analysis, visual analysis, archeological and history/architectural surveys, geotechnical surveys, noise analysis, public engagement, environmental studies and coordination with public agencies.	90 days	Yes. Public engagement and tribal consultation is required.	30 days
	PUCO – OPSB	Certificate Application for Electric Generation Facilities Ohio Administrative Code Chapter 4906-4	Required for electric generating plants and associated facilities designed for, or capable of, operation at a capacity of fifty megawatts or more.	Abbreviated Certificate Application (Letter of Notification if facility uses waste heat or natural gas and is primarily within the current boundary of an existing industrial or electric generation facility. All other electric generation facilities require Standard Certificate Application)	60-90 days	Yes. Public engagement and tribal consultation is required.	30 days

Table 3 (continued): State of Ohio Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transport	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)				Studies include alternative analysis, visual analysis, air permitting, archeological and history/architectural surveys, geotechnical surveys, noise analysis, public engagement, environmental studies and coordination with public agencies.			
	Rail Lines (Various Rail Providers)	Railroad Right-of-Way (ROW) Crossing Easement Ohio Revised Code Chapter 4955	Crossing or utilizing railroad ROW/easements	Submittal of crossing request with location drawing, application form, and engineered plan and profile.	Not identified. It depends on the rail provider	No public engagement required	N/A
	Public or Private Utilities (various utility provider)	Utility Crossing Easement Ohio Revised Code Section 4905.90	Crossing or utilizing utility ROW/easements	Project Notification and request “One Calls” in advance of construction. Coordination with the public or private utility involved.	Not identified. It depends on the utility provider	No public engagement required	N/A
Trucks	Ohio Public Utilities Commission	Ohio Public Utilities Commission (PUCO) Registration Ohio Administrative Code (OAC) 4901:2	All trucks transporting CO_2/any hazardous materials for commerce are subject to PUCO Registration to comply with safety operational standards	N/A	1 - 3 days	No public engagement required	N/A
Railroad	N/A *(No specific state regulation/permitting for railroad CO_2 transportation in Ohio. This mode of transportation is regulated by the federal government)						

Table 4: State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines	Pennsylvania Department of Environmental Protection (PADEP) Southwest Regional Office Waterways and Wetlands	Chapter 105 Water Obstruction and Encroachment General Permit (GP) Chapter 105 Water Obstruction and Encroachment Joint Permit (JPA)	When there are proposed impacts to wetland and waterbody resources Under Pennsylvania State Programmatic General Permit 6 (PASPGP-6) a Chapter 105 Permit may satisfy the required Federal Section 404 United States Army Corps of Engineers (USACE) Permit	Chapter 105 General Permit (GP) Registration Chapter 105 Joint Permit Application (JPA)	60 - 90 days for a Chapter 105 GP Minimum of 180 days for a Chapter 105 JPA	N/A	N/A
		Chapter 105 GP-04 (Intake/Outfall Structure)	The construction, operation, and maintenance of intake and outfall structures in, along, across or projecting into the regulated waters of the Commonwealth. This authorization is pursuant to Section 7 of the Dam Safety and Encroachments Act, 32 P.S. §693.1, et seq., and the rules and regulations promulgated thereunder at 25 Pennsylvania Code §105.441-105.449	Chapter 105 General Permit (GP) Registration	60 - 90 days for a Chapter 105 GP	N/A	N/A
		CWA/Section 404 - Pennsylvania State Programmatic General Permit-6 (PASPGP-6)	Reportable and Non-Reportable based on impact thresholds Authorization request typically filed concurrently with a PADEP Chapter 105 Water Obstruction and Encroachment Permit - General Permits	Based on impact thresholds, separate federal review/authorization may be required, may be satisfied by a PADEP Chapter 105 Permit with or without USACE review	60 to 90 days for a PADEP Chapter 105 General Permit (GP): may be longer if Reportable Activity thresholds are involved	N/A	N/A
		PAG-02 NPDES General Permit for Discharges of Stormwater Associated with Construction Activities Clean Streams Law (35 P.S. Section 691.1 et seq.)	Required for projects with earth disturbance activities greater than or equal to one acre. PAG-02 may be used for projects disturbing greater than 5 acres. Reviewed and authorized through PA DEP or a Chapter 102 Delegated County Conservation District.	NOI package includes attachments identified on the NOI checklist (3800-PM-BCW0405a)	90 days	Yes. Public engagement is required.	30 days
		PAG -03 Discharges of Stormwater Associated with Industrial Activities - Water Quality Management	National Pollutant Discharge Elimination System (NPDES) permit coverage for discharges of stormwater	NOI package includes the NOI form and all other attachments identified on the	90 - 180 days	Yes. Public engagement is required for Water Quality	30 days

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)	Pennsylvania Department of Environmental Protection (PADEP) Southwest Regional Office Waterways and Wetlands (Continued)	Permit (WQM) Clean Streams Law and Water Quality Standards on PA. Code Chapter 93	associated with industrial activity, as defined at 40 CFR § 122.26(b)(14) (PAG-03 Appendix J – Additional Facilities)	NOI checklist (3800-PM-BCW0083c)		Management permits.	
		PAG-10 NPDES General Permit for Discharges from Hydrostatic Testing of Tanks and Pipelines Section 402 of the CWA (40 CFR Part 122) - NPDES Program	For the discharge of water used for the hydrostatic testing of existing or proposed tanks or pipelines.	NOI package includes the NOI form, and all other attachments identified on the NOI checklist (3800-PM-BCW0173c).	60 days	N/A	N/A
		CWA Section 401: State Water Quality Certification (SWQC)	Section 401 is triggered if the construction or operation of a facility (1) requires a Federal license or approval (e.g. a Section 404 Permit from the U.S. Army Corps of Engineers) and (2) the construction or operation of the facility will cause a discharge into navigable waters.	Applicant must provide the permitting agency with a certification from PADEP indicating that the discharge will comply with effluent limitations, water quality standards, and performance standards (typically satisfied/issued by a PADEP as part of the Chapter 105 Permit authorization)	60 - 180 days (DONE CONCURRENTLY WITH 404 PERMITTING)	Yes. The notice must occur within 20 calendar days from receiving the request.	30-45 days
		Erosion and Sediment Control General Permit-4 (ESCGP-4) for 5 or more acres of Earth Disturbance Associated with Oil and Gas Exploration, Producing, Processing, or Treatment Operations or Transmission Facilities Clean Streams Law Title 25, Chapter 102	Oil and gas activities that involve five (5) acres or more over the life of the Project.	NOI package includes the NOI form, and all other attachments identified on the NOI checklist (8000-PM-OOGM0003d).	60 days	N/A	N/A
		Chapter 106 Floodplain Management Authorization	When there are potential impacts or development proposed inside floodplains Typically obtained in conjunction with the PADEP Chapter 105 Water Obstruction and Encroachment Permit. Projects that require a PADEP Chapter 105 authorization usually do not require an	Chapter 106 Authorization (can likely be satisfied by a PADEP Chapter 105 Permit)	60 to 90 days for a Chapter 105 GP Minimum of 180 days for a Chapter 105 JPA 60 days if requesting Chapter 106 Authorization separately (Chapter 105 Permitting not required)	N/A	N/A

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)			additional application for a Chapter 106 Permit. Projects that are located entirely outside of watercourses, floodways, and bodies of water, but ARE located within a floodplain may need a separate Chapter 106 Authorization.				
		Submerged Lands License Agreement (SLAA) Chapter 105	When crossing or affecting submerged lands of the Commonwealth (listed public streambeds)	Typically completed as part of the Chapter 105 Water Obstruction and Encroachment Permit A yearly annual fee is required	60 to 90 days for a Chapter 105 GP Minimum of 180 days for a Chapter 105 JPA	N/A	N/A
	Pennsylvania Department of Environmental Protection (PADEP) Bureau of Air Quality	Air Plan Approval Air Pollution Control Act. 25 PA Code Chapter 127, Subpart B	Minor Source Air Plan Approval if potential to emit (PTE) for regulated New Source Review (NSR) pollutants, such as, carbon monoxide, particulate matter, sulfur dioxide and lead are less than 100 TPY. For the project location, minor source Plan Approval if PTE for nitrogen oxides and volatile organic compounds are less than 100 TPY and 50 TPY, respectively. Minor source Air Plan Approval if hazardous air pollutant emissions are less than 10 tpy of a single hazardous air pollutant (HAP) or 25 TPY of any combination of HAPs. A Major Source Air Plan Approval if PTE of NSR pollutants and HAPs are equal to or more than the above-mentioned emission threshold values that qualifies a facility to obtain Minor Source Plan Approval.	Applicability Determination	180 calendar days from receipt of complete permit application.	Major sources Air Plan Approval and synthetic minor sources are required public comment period and public hearings	30 days

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)		Title V Operating Permit for a major source or State Operating Permit for a minor source. 25 PA. Code Chapter 127, Subchapter G	Prior to commencing operation of a source with potential to emit air pollutants.	Submit State Only or Title V Operating Permit application.	18 months from receiving a complete application	Yes. both Title V Operating Permit for major Source and State Operating Permit for minor source required public engagement	30 days
	Pennsylvania Department of Environmental Protection (PADEP) Bureau of Environmental Cleanup and Brownfields Division of Storage Tanks	Operating Permit Carbon Capture and Sequestration Act	An Operating Permit allows the tank owner to operate a storage tank system. Operating permits are automatically renewed each year concurrent with proper registration if the minimal requirements are met.	The tank owner's registration certificate will indicate the permit status for each tank. No additional paperwork or fees beyond the annual registration requirements are needed for renewal.	30 - 60 days	Yes. Carbon Capture and Sequestration Act requires public engagement for Operating Permit.	30 days
		Above Ground Storage Tank (AST) Registrations Storage Tank and Spill Prevention Act	Regulated ASTs are defined as stationary tanks used to contain regulated substances with a capacity of more than 250 gallons, where more than 90 percent of the volume is upon or above the supporting surface of the Regulated ASTs are defined as stationary tanks used to contain regulated substances with a capacity of more than 250 gallons, where more than 90 percent of the volume is upon or above the supporting surface of the ground and can be visibly inspected. This includes tanks that can be visibly inspected in an underground area or in a building.	Annual Registration Fee/Application must be filed each year to maintain compliance. Fee varies with capacity from \$50 - \$300	30 - 60 days	N/A	N/A
	Pennsylvania Game Commission (PGC)	PGC Federal/State Threatened & Endangered Species Consultation State Game Land Approval (over 300 State Game Land tracts in Pennsylvania)	When the results of the Pennsylvania Natural Heritage Program (PNHP) Pennsylvania Natural Diversity Index (PNDI) screening and receipt result in a potential impact on a species	PNDI Screening Consultation with PGC On-site habitat assessments Biological assessment of potential impacts Species-specific surveys	PNDI results - instant If consultation required: 30-45 days to review If required habitat assessment or biological surveys : 30 - 60 days to	Yes. Under Pennsylvania's state laws, public engagement is required during the Threatened & Endangered	30 days

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)		Game and Wildlife Code (34 Pa. C.S. §§ 102, 925, 2164-67, 2924), and the Wild Resource Conservation Act	under the jurisdiction of the PGC		review field report Time of year restrictions may be agreed to without habitat assessments or biological surveys	species consultation process.	
	Pennsylvania Department of Conservation and Natural Resources (PA DCNR)	PA DCNR Federal/State Threatened & Endangered Species Consultation Pennsylvania Endangered Species Act	When the results of the PNHP PNDI screening and receipt result in a potential impact to a species under the jurisdiction of the PA DCNR	PNDI Screening Consultation with PA DCNR On-site habitat assessments Biological assessment of potential impacts Species-specific surveys	PNDI results - instant If consultation required: 30-45 days to review If required habitat assessment or biological surveys: 30 - 60 days to review field report Time of year restrictions may be agreed to without habitat assessments or biological surveys	N/A	N/A
	Pennsylvania Department of Conservation and Natural Resources (PA DCNR) - State Forest Management (20 State Forest in Commonwealth of PA)	Special Use Permit Conservation of Natural Resources Act. 58 Pa. Code Chapter 147	Required for the approved use on State Forest property	Requires consultation with State Forester to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural surveys, wetland/waterbody delineation, and PNDI review.	30-60 days	N/A	N/A
	Pennsylvania Department of Conservation and Natural Resources (PA DCNR) - Bureau of State Parks (124 State Parks in Commonwealth of PA)	Special Use Permit Title 17 Pa. Code Chapter 147	Required for the approved use on State Park property	Requires consultation with the State Park to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural surveys, wetland/waterbody delineation, and PNDI review.	30-60 days	N/A	N/A
	Pennsylvania Fish and Boat Commission (PFBC)	PFBC Federal/State Threatened & Endangered Species Consultation Pennsylvania Fish and Boat Code 30 Pa. C.S. §§102	When the results of the PNHP PNDI screening and receipt results result in a potential impact to a species under the jurisdiction of the PFBC	PNDI Screening Consultation with PFBC On-site habitat assessments Biological assessment of potential impacts Species-specific surveys	PNDI results - instant If consultation required: 30-45 days to review If required habitat assessment or biological surveys: 30 - 60 days to review field report	N/A	N/A

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)					Time of year restrictions may be agreed to without habitat assessments or biological surveys		
	Pennsylvania Bureau for Historic Preservation; Pennsylvania Historical and Museum Commission (PHMC) Pennsylvania State Historic Preservation Office (PA SHPO)	National Historic Preservation Act Section 106 Concurrence	When there are potential impacts to cultural and/or historical resources; or required through Federal Nexus	Request for Concurrence from the PA SHPO	30 days	Yes. Federal agencies must consider tribal consultation and public views about historic preservation issues.	30 days
	Pennsylvania Department of Transportation (PennDOT District 12-0)	PA Code Title 67: Highway Occupancy Permit (HOP) 67 PA. Code Chapter 459	When a project requires work within the ROW, upgrading or reclassifying existing access roads or driveways to state highways/roadways.	Civil surveys to obtain sight distance Permit Application	60 days	N/A	N/A
	Pennsylvania Public Utility Commission (PUC)	Rail Safety Applications - Railroad ROW Crossing / Licensing Agreement (Application Form G) 52 Pa. Code Chapter 33, Railroad Transportation	When a new railroad ROW crossing is needed to access a project.	Submittal of crossing request with location drawing, application form, and engineered plan and profile	45-90 days	N/A	N/A
		Utility Crossing Applications - Railroad ROW Crossing / Licensing Agreement (Application Form W) Title 52 of the Pennsylvania Code, Chapter 33	When utility lines must cross a railroad ROW to service a project.	Submittal of crossing request with location drawing, application form, and engineered plan and profile	45-90 days	N/A	30 days
		Pipeline Access Permit The Gas and Hazardous Liquids Pipelines Act 127 of 2011	Depends on the project scope	Assumes potential for studies as determined on site-specific basis during NEPA analysis or other applicable permitting requirements.	120 days	Yes. Public engagement is required particularly for project scope involving significant environmental impacts	
	Rail Lines (Various Rail Providers)	Railroad Right-of-Way (ROW) Crossing Easement	Crossing or utilizing railroad ROW/easements	Submittal of crossing request with location drawing,	Not identified. It depends on the rail providers	N/A	N/A

Table 4 (continued): State of Pennsylvania Permitting and Regulation Requirements for CO_2 Transportation

Mode of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipelines (continued)		Title 52, Chapter 33, of the Pennsylvania Code		application form, and engineered plan and profile			
	Private Gas/Electric	Utility Crossing Easement Title 66 of the Pennsylvania Public Utility Code	Crossing or utilizing gas/electric utility ROW/easements.	Project Notification and request “One Calls” in advance of construction.	Not identified	N/A	N/A
Trucks	Pennsylvania Department of Environmental Protection (PADEP)	Hazardous Waste Transporter License 25 PA. Code, Chapter 263a and 40 CFR Part 263	CO_2 is not classified as hazardous waste; however, CO_2 may be considered as hazardous waste based on its specific characteristics and transported quantities.	A compliance history form (Form HW-C) to be submitted. Additionally, The Collateral Bond Form. a transporter contingency plan and proof of liability insurance need to be submitted.	60 days	N/A	N/A
Railroad	N/A *(No specific state regulation/permitting for railroad CO_2 transportation in Pennsylvania. This mode of transportation is regulated by the federal government)						

Table 5: State of West Virgina Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline	West Virginia Department of Environmental Protection (WVDEP) - Division of Water and Waste Management	Section 401 Water Quality Certification CWA	When the project requires a permit or license by a federal agency for potential impacts of waters of the U.S./State in accordance with the State's water quality standards or stream designated uses. Individual Water Quality Certification (WQC) may be needed should the regional Special Conditions of the 404 NWP not be met.	Associated with a USACE Section 404 permit. Stream and wetland delineation may be required. Stream and/or wetland mitigation may be required. H19 Notification may be required.	60 days	Yes. Public engagement is required for the Water Quality Certification specifically for individual certification requests	30 days
		NPDES Permits	Project may require a General Water Pollution Control Permit for stormwater associated with construction activities. As the CO_2 pipelines may involve a discharge from point source into a water of the United States, NPDES permit is required. The pipelines will transport CO_2 for Class VI well injection, WV currently has granted state primacy for regulating these well, hence, the state can issue permits for these activities.	Application to be filed would require a Stormwater Pollution Prevention Plan (SWPPP), a Groundwater Protection Plan (GPP), and water quality parameters. Karst Mitigation Plan may be required. Chesapeake Bay Addendum may be required. The Individual Permit may also require a public comment and hearing.	60 days	Yes. Public engagement is required. The process includes public notice soliciting public comments and holding public hearing based on public interest.	30 days
		Multi-Sector Stormwater General Permit	A Multi-Sector Stormwater General Permit is required for industrial facilities that qualify under listed coverage.		180 days	Yes. Public engagement is required for non-Stormwater Permit. The process includes public notice, giving public the opportunity to comment on the proposed permit actions. WVDEP addresses public comments in writing and conduct public hearings if requested by public.	30 days

Table 5 (continued): State of West Virginia Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline (Continued)	West Virginia Department of Environmental Protection (WVDEP) - Division of Water and Waste Management (continued)	Individual WV/NPDES Permit	An Individual WV/NPDES Permit may be required for facilities/operations that are not covered under the Multi-Sector Stormwater General Permit.		180 days	Yes. Public engagement is required for individual WV/NPDES permits. There is a formal public engagement process that includes developing and publishing a draft permit, offering opportunities for public comments and holding public hearing if required.	30 days
		Non-Stormwater General Permit	Non-Stormwater General Permit that may be applicable based on project specifications include Hydrostatic Testing, Sewage Sludge (Land Application and Disposal), Sewage (less than 50,000 gallons per day), Water Treatment Plants, and Pesticide General Permit.	Application to be filed would require a SWPPP, GPP, and water quality parameters, depending on the type of discharge. Compliance with West Virginia's Chesapeake Bay Program, Watershed Implementation Plan (WIP) for Chesapeake Bay Total Maximum Daily Load (TMDL) required.	30-180 days	Yes. Public engagement is required for Non-Stormwater Permit. The process include public notice with giving public the opportunity to comment on the proposed permit actions. WVDEP addresses public comments in writing and conducts public hearings if requested by public.	30 days
		State Water Permit West Virginia Water Pollution Control Act (WPCA)	Required when project may cause an alteration to the physical or biological integrity of any non-jurisdictional (or isolated) water of the State.	Associated with a USACE Section 401 Water Quality Certification. Stream and wetland delineation may be required. Stream and/or wetland mitigation may be required.	30 - 45 days	No public engagement required	N/A
		Aboveground (AST) Registration Aboveground Storage Tank Act. WVa Code § 22-30-1	An above-ground storage tank that meets the conditions for registration will be registered if applicable and as deemed necessary.	Requires owners of USTs to complete a DEP Notification Form	30 days	No public engagement required	N/A

Table 5 (continued): State of West Virginia Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline (Continued)	WVDEP Division of Air Quality (DEQ)	Minor Source Air Permit to Construct 45CSR13-Minor New Source Review Permitting	Prior to constructing a source with potential to emit air pollutants if potential to emit (PTE) before controls at or above 5 TPY.	Applicability determination based on actual operations.	Not to exceed 90 calendar days, after the date the Secretary determines the application is complete.	Yes. Public engagement is required for the Minor Source Air Permit, Minor Source Permit to install, and Synthetic minor source permit under the 45CSR12 regulations that governs permitting new sources and modifications of existing sources.	30 days
Pipeline (Continued)	WVDEP Division of Air Quality (DEQ)	Minor Source Air Permit to Install 45CSR13-Minor New Source Review Permitting	Prior to constructing a source with potential to emit air pollutants if hazardous air pollutant emissions are less than 10TPY	Applicability determination based on actual operations.	Not to exceed 90 calendar days, after the date the Secretary determines the application is complete.	Yes. Public engagement is required for the Minor Source Air Permit, Minor Source Permit to install, and Synthetic minor source permit under the 45CSR12 regulations that governs permitting new sources and modifications of existing sources.	30 days
Pipeline (Continued)	WVDEP Division of Air Quality (DEQ)	Synthetic Minor Permit to Construct 45CSR13-Minor New Source Review Permitting	Prior to constructing a source with potential to emit air pollutants	Applicability determination based on actual operations.	Not to exceed 90 calendar days, after the date the Secretary determines the application is complete.	Yes. Public engagement is required for the Minor Source Air Permit, Minor Source Permit to install, and Synthetic minor source permit under the 45CSR12 regulations that governs permitting new sources and modifications of existing sources.	30 days
Pipeline (Continued)	WVDEP Division of Air Quality (DEQ)	Construction Permit (R13)/Title V permit West Virginia Water Pollution Control Act (WPCA)	Prior to the start of construction	Emissions calculations; process description; and process flow diagrams.	45-90 days	Yes. Public engagement is required. The process includes public notice to solicit public comments on the proposed permit and potentially request public hearing or appeal decision.	30 days
Pipeline (Continued)	West Virginia Historic Preservation Office (WVHPO)-Division of Culture and History	National Historic Preservation Act, Section 106 Consultation	When a federal agency must take an action on a project, creating a federal nexus. This includes when a federal agency is carrying out the project, if federal authorization or approval is needed (such as from the USACE or BLM), or if the federal government is funding the project.	Desktop review to identify historic properties and an assessment of adverse effects with the State Historic Preservation Officer (SHPO) and/or Tripal Historic Preservation Officer (THPO)	30 days	Yes. Public engagement and tribal consultation are required and their views and concerns regarding historic preservation issues need to be considered	30 days
Pipeline (Continued)	WV Division of Natural Resources (WVDNR)	Natural Heritage Program Class VI Well- WV's Underground Injection Control (UIC) Program	Rare, threatened, and endangered (RTE) species list provided for development projects, such as subdivisions, infrastructure projects, highway design, pipeline corridors, and communication towers	Coordination required	30-60 days	Public engagement is not required	N/A

Table 5 (continued): State of West Virgina Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline (Continued)	WV Division of Natural Resources (WVDNR) (continued)	Fish Spawning Waivers Natural Streams Prevention Act	For in-stream work between April 1-June 30	Coordination required	Not identified	Public engagement is required	N/A
		Wildlife Management Area (WMA) Review West Virginia Code of State Rules § 58-31-2	Evaluation of WMAs, prior to Project implementation	Habitat assessment	Not identified	Public engagement is not required	N/A
		Surface Water Withdrawal Permit Water Management Plan - W. Va. Code R. § 35-8	Required prior to surface water withdrawal, if needed	Stream delineation, volume and location data.	180 days	Yes. Public engagement is required. For general permit issuance and reissuance, public hearing is required, and public provided a chance to comment on the proposed permit actions.	30 days
	WVDNR Office of Land and Streams (OLS)	Stream Activity Right-of-Entry	Required when there is an activity involving a stream or river requires Right-Of Entry from the Office of Land and Streams	Stream Activity Application. If there are multiple streams involved, the Office of Land and Streams Application Table should be included.	60 days	Yes. Public engagement is required as a part of obtaining the Stream Activity Right-of-Entry.	30 days
	WVDNR and WV Division of Forestry (9 State Forest in WV)	Special Use Permit West Virginia Code § 20-3	Required for the approved use on State Forest property.	Requires consultation with State Forester to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural surveys, wetland/waterbody delineation, and Natural Heritage Program review.	90-180 days	Public engagement is not required	N/A

Table 5 (continued): State of West Virginia Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Pipeline (Continued)	WVDNR-State Parks (36 State Parks in WV)	Special Use Permit W. Va. Code R. § 58-31-2	Required for the approved use on State Park property	Requires consultation with the State Park to determine permitting requirements. Clearances/surveys for federally listed species and state-listed threatened and endangered species, cultural surveys, wetland/waterbody delineation, and Natural Heritage Program review.	90-180 days	Yes. Public engagement is required for the Special Use Permit in WV State Parks	30 days
	WV Department of Highways (WVDOH)	Temporary Construction Access / Right-of Way Encroachment Permit / Special Load WVDOH/ Chapter 17 and Chapter 17C	Application(s) to be filed for any ROW encroachment for access.	Highways' specifications for driveway construction are designed to provide adequate sight distance for traffic, proper roadway drainage and suitable slopes for road	7-20 days	Public engagement is not required	N/A
	WV State Emergency Management Division	Tier II Filing Emergency Planning and Community Right-to-Know Act (EPCRA)	Facilities with hazardous chemicals on hand in quantities equal to or greater than set threshold levels.	Basic facility info, employee contact, information about chemicals stored	N/A	Public engagement is not required	N/A
	Public or Private Utilities (Various Utility Providers)	Utility Crossing Easement West Virginia Code of State Rules, Section 150-7-7	Crossing or utilizing utility Right-of-Way/easements	Project Notification and request "One Calls" in advance of construction. Coordination with the public or private utility involved.	Not specified. depending on the utility provider	Public engagement is not required	N/A
Trucks	WV Department of Highways (WVDOH)	Special Hauling Permit West Virginia Code §17C-17-1	When the vehicle or loads exceed certain limits	N/A	The review time may vary based on the application and its complexity.	Public engagement is not required	N/A

Table 5 (continued): State of West Virgina Permitting and Regulation Requirements for CO_2 Transportation

Moe of Transportation	Regulatory Agency	Permit & Federal Laws/Regulations	When Required	Potential Studies & Application Requirements	Estimated Agency Review Time	Public Involvement Required	Public Comment Period
Trucks (Continued)	WV Department of Highways (WVDOH) (continued)	Clearance West Virginia Code §17C-12	Required when truck weight, height, and loading exceed the federal limits	N/A	60 days	Public engagement is not required	N/A
Railroad		Clearance W. Va. Code R. § 150-8-3 - rules relating to Clearances	Required for expansion of rail siding	Details regarding expansion	60 days	Public engagement is not required	N/A

Appendix 2. Technoeconomic Assessment and Business Case Analysis

DOE Award No. DE-FE0032487

Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION)

Business Case Analysis

United States Department of Energy
National Energy Technology Laboratory

August 2025

BATTELLE

DOE Award No. DE-FE0032487

Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION)

Business Case Analysis

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Acronyms

APOS	Allocation at the Point of Substitution
BCA	Business Case Analysis
CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CEPCI	Chemical Engineering Plant Cost Index
CO_2NNECTION	Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore
CO_2	Carbon Dioxide
DCF	Discounted Cash Flow
DOE	U.S. Department of Energy
FECM	Office of Fossil Energy and Carbon Management
FEED	Front End Engineering Design
IEA	International Energy Agency
IRR	Internal Rate of Return
LCA	Lifecycle Assessment
NETL	National Energy Technology Laboratory
NG	Natural Gas
NPV	Net Present Value
NZE	Net Zero Emissions
OH	Ohio
OPEX	Operating Expenditures
PA	Pennsylvania
RGGI	Regional Greenhouse Gas Initiative
SME	Subject Matter Expert
SOPO	Statement of Project Objectives
TRC	TRC Companies, Inc.
U.S.	United States
WV	West Virginia

Executive Summary

This document summarizes the business case analysis (BCA) completed as part of the Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) Intermodal Transport Hubs project. This BCA evaluates the economic and logistical feasibility of transporting captured carbon dioxide (CO_2) from point-source emitters—such as natural gas power plants and industrial facilities—to injection wells for permanent geologic storage. The geographic focus is the tri-state region of Ohio (OH), West Virginia (WV), and Pennsylvania (PA), which is an area with significant CO_2 emissions and promising subsurface storage potential. The analysis evaluates three primary transportation modes: truck, rail, and pipeline, using publicly available cost models and literature to inform capital and operating expenditure estimates.

Two primary scenarios were evaluated along with three sub-scenarios to determine the economic viability of the studied CO_2 transportation network. Scenario 1 evaluates the capture and congregation of existing carbon sources via rail, train, and pipeline to an injection well. Three sub-scenarios were developed for Scenario 1 to evaluate the viability of incorporating sources that are farther from the primary pipeline. Scenario 2 considers the impact of a newly constructed hydrogen plant on the intermodal transport hub. The scenarios and sub-scenarios were compared primarily by their net present value (NPV), internal rate of return (IRR), and break-even price of CO_2.

All scenarios showed economic viability when supported by Internal Revenue Code Section 45Q, Credit for Carbon Oxide Sequestration (45Q) tax credits. The break-even price of CO_2 in the scenarios ranges from $5 to $31 per tonne, which is below the anticipated $85 per tonne tax credit. The scenario with the lowest identified breakeven cost was Scenario 1A, which only utilizes pipelines for transportation. This conclusion aligns with CO_2 transportation literature, which traditionally indicates that transportation of CO_2 via pipeline is the most economical approach for large volumes over longer distances (McCoy and Rubin, 2008). While truck and rail provide suitable outreach to other, smaller sources, they are not as economically efficient or carbon efficient as pipelines for large volumes of CO_2. A more detailed economic evaluation is warranted to further refine the BCA. Key next steps include updating pipeline cost estimates with more robust and region-specific data sets, benchmarking costs to recent projects, and identifying opportunities for cost optimization.

1.0 Introduction

This document summarizes the business case analysis (BCA) completed as part of the Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) Intermodal Transport Hubs project. This BCA was performed for the United States (U.S.) Department of Energy (DOE) to satisfy the award requirements for DE-FE-0032487. This BCA report is intended to be reviewed as part of the larger CO_2NNECTION final report and pre front-end engineering design (pre-FEED) summary.

The transportation of carbon dioxide (CO_2) from point source emitters, such as natural gas processing plants, to designated injection wells is a critical component of carbon capture and storage (CCS) strategies aimed at reducing greenhouse gas emissions. This BCA explores the logistical and economic considerations of three primary transportation modes: truck, rail, and pipeline. Each method presents unique advantages and challenges in terms of scalability, cost-effectiveness, infrastructure requirements, and regulatory compliance. Trucking offers flexibility and low initial capital investment, making it suitable for small-scale or early-stage CCS projects, but it is limited by capacity and higher per-ton transport costs. Rail transport provides a middle ground, offering greater volume capacity and moderate infrastructure needs, though it requires access to rail networks and transloading facilities. Pipelines, while capital-intensive and subject to stringent permitting processes, offer the most efficient and cost-effective solution for large-scale, continuous CO_2 transport over long distances. This BCA will review the cost of each transportation method of the proposed multi-modal hub in two primary scenarios, with one including smaller sub-scenarios to determine the impacts of more distant sources on the network's economics.

2.0 Business Case Analysis

The intended application of this analysis is to understand the business case for implementing the intermodal CO_2 transport hub. This document first outlines the process to quantify operating costs; revenues; cash flows; earnings before interest, taxes, depreciation, and amortization; tax credits and liabilities; and project return on investment. The methodology and technoeconomic assessment results are followed by discussions on market analysis, projection of future deployment scenarios, and quantification of the potential benefits of technology implementation. Particular attention is paid to applying 45Q credits to the project's costs through an analysis of existing processes and methods applied by the industry in offsetting infrastructure costs.

2.1 Methodology

The project's net present value (NPV) and internal rate of return (IRR) were calculated using a discounted cash flow (DCF) model. The approach to calculating these values is further described in Section 2.1.1. Based on 45Q credits for geological storage from point-source capture, a revenue of $85 per net tonne of CO_2 transported was assumed (Carbon Capture Coalition, 2025).

A selection of scenarios and sub-scenarios was considered to understand the influence of various sources and modes of transportation on the project. Two primary scenarios are presented (Appendix C). These scenarios are defined in Table 1 and Table 2**.** The first gathers CO_2 from hypothetical sources that currently exist in the study area, focusing on small- and medium-sized sources throughout southwestern PA, northern WV, and eastern OH. The second scenario explores how the network would change with the introduction of a hydrogen plant in Doddridge County, WV. The hydrogen plant is assumed to use natural gas as a feedstock and capture the CO_2 resulting from hydrogen production.

Table 1. Overview of scenarios and sub-scenarios considered in the DCF

Scenario	Description	Changes from Scenario 1
Scenario 1	Gathers CO_2 from hypothetical locations of sources that currently exist in the study area, focusing on small and medium-sized sources throughout southwestern PA, northern WV, and eastern OH	*N/A*
Scenario 2	Considers the impact of a newly constructed hydrogen plant on the intermodal transport hub	- *Natural Gas (NG) Compressor C:* 70,000 TPA meeting pipeline in Wetzel County, WV - *NG Compressor D:* 40,000 transported to hydrogen plant via pipeline - *Railyard 1:* 500,000 TPA **additional** - *Railyard 2:* 40,000 TPA **less** (new amount: 110,000 TPA) - *Railyard 3:* No longer used
Scenario 1A – Only Pipeline	Same as Scenario 1, but excludes all methods of transportation and CO_2 sources other than pipelines and CO_2 originating at pipeline hubs	- *NG Compressor A:* No longer used - *NG Compressor B:* No longer used - *NG Compressor D:* No longer used - *NG Compressor E:* No longer used - *NG Compressor G:* No longer used

Table 1 (continued). Overview of scenarios and sub-scenarios considered in the DCF

Scenario	Description	Changes from Scenario 1
		- *Railyard 1:* No longer used - *Railyard 2:* No longer used - *Railyard 3:* No longer used
Scenario 1B – Fewer Trucking Connections	Same as Scenario 1, but excludes three trucking routes that connect at Railyard 2 and one trucking route that connects at Railyard 3	- *NG Compressor B:* No longer used - *NG Compressor C:* No longer used - *NG Compressor D:* No longer used - *NG Compressor E:* No longer used - *Railyard 3:* No longer used
Scenario 1C – No Railyard 3	Same as Scenario 1, but excludes Railyard 3 and its associated CO_2 source	- *NG Compressor C:* No longer used - *Railyard 3:* No longer used

Table 2. Masses and distances of CO_2 transported in scenarios and sub-scenarios

Parameter	Units	Scenario 1 - Original	Scenario 2 - Original	Scenario 1A - Only Pipeline	Scenario 1B - Fewer Trucking Connections	Scenario 1C - No Railyard 3
CO_2 transported via truck	kilotonnes / year	270	160		80	200
CO_2 transported via rail	kilotonnes / year	220	110		40	150
CO_2 transported via pipeline *(8-inch diameter - total)*	kilotonnes / year	3175	4435	2175	3175	3175
8-inch diameter pipeline capacity	tonnes / day	10000	10000	10000	10000	10000
CO_2 transported via pipeline *(12-inch diameter)*	kilotonnes / year	1670	2170	1400	1480	1600
12-inch diameter pipeline capacity	tonnes / day	5000	10000	5000	5000	5000
Distance transported via truck	miles	140	55		11	129
Distance transported via rail	miles	225	140		139	139
Distance transported via pipeline *(8-inch diameter)*	miles	21.8	136	21.8	21.8	21.8
Distance transported via pipeline *(12-inch diameter)*	miles	74.8	74.8	74.8	74.8	74.8

Maps displaying the CO_2 sources and routes associated with each scenario and sub-scenario are presented in Appendix C. Costs and lifecycle data for the various modes of CO_2 transport were obtained as described in subsequent sections.

2.1.1 Technoeconomic Assessment

Truck and Rail

Truck and rail cost estimates (both capital expenditures [CAPEX] and operating expenditures [OPEX]) were obtained using the methodology outlined by Myers et al. (2024) and thus follow the assumptions defined therein. The most notable of these assumptions are as follows:

- All CO_2 transportation equipment and logistical systems are designed from the bottom up, utilize the best available technology, and account for current regulatory requirements
- Buffer storage of CO_2 after liquefaction and before reconditioning is included
    - Buffer storage tanks are costed as vertical, 105 m^3 capacity, double-wall, vacuum-sealed vessels with a 304 L stainless steel inner vessel and a carbon steel outer vessel
    - The amount of buffer storage is calculated automatically by the model established by Myers et al. (2024) based on user-defined inputs. The scenarios defined herein use between 3 and 15 buffer storage tanks.
- OPEX includes estimates for electricity, fuel, makeup water, maintenance, insurance, permits, fees, labor, and end of life costs
- The physical condition of CO_2 across the transport network was assumed to correspond to the values presented in Table 3. These purity values are higher than the range (90-99%) that would be anticipated for CO_2NNECTION, and further iterations of the economic assessment will seek to address this discrepancy.

Table 3. Physical condition of CO_2 at various points in the transport network*

CO_2 State	Purity	Temperature (°C)	Pressure (MPa)	Density (kg/m^3)
Unpressurized (as received)	100 %	20	0.1	1.8
Liquefied (as transported)	100 %	-28	1.5	1042
Supercritical (reconditioned for delivery)	100 %	15	10.1	890

**Assumed by Myers et al. (2024)*

Additionally, the following simplifying assumptions were made by the CO_2NNECTION team for the purpose of obtaining a high-level cost analysis:

- Transport costs and impacts for truck and rail were each calculated as one route transporting the total mass of CO_2 to be transported by each method
- The geographical scale and location were selected as “Regional” and “East,” respectively
- The container type was assumed to be intermodal for both truck and rail

Detailed inputs to the truck and rail economic assessment models are provided in Table B-4 and Table B-5.

Pipeline

After further review by the CO_2NNECTION project team, it was determined that the Office of Fossil Energy and Carbon Management / National Energy Technology Laboratory (FECM/NETL) CO_2 Transport Cost Model originally specified in the Statement of Project Objectives (SOPO) is not capable of efficiently modeling pipeline networks. Instead, it is more applicable for single source/sink pipeline scenarios. As a result, pipeline capital cost estimates were largely obtained using the methodology outlined by McCollum and Ogden (2006), which estimates capital cost as a function of pipeline length and CO_2 mass flow rate as opposed to conventional inch-mile estimates. The FECM/NETL CO_2 Transport Cost Model (Morgan and Shih, 2024) was only utilized to estimate the CAPEX and OPEX associated with pumping the truck and rail CO_2 volume to pipeline specifications.

Mass flow rates for the intermodal transport network pipelines were rounded up to the nearest of the four values (1,000, 5,000, 10,000, or 20,000 tonnes per day) to match with one of McCollum and Ogden's four cost curves. Costs were adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI) values (averaged over year) for 2006 and 2024. Annual operating expenses were conservatively assumed to be 4% of capital expenses (Solomon et al., 2024), and other labor costs were assumed to be negligible.

Key Financial Results

Key financial results for the technoeconomic assessment included NPV, IRR, and breakeven price. NPV and IRR were calculated for each scenario and sub-scenario using a DCF model. Key economic inputs to the model are outlined in Appendix B. NPV was calculated by summing the discounted cash flow over the project lifetime. IRR was calculated using Excel's IRR function. The breakeven price of CO_2 was calculated using Excel's Goal Seek function, wherein NPV was set to $0 by adjusting the selling price of CO_2.

2.1.2 Lifecycle Assessment

Truck and Rail

Truck and rail lifecycle assessment (LCA) data were obtained using the methodology outlined by Myers et al. (2024) and thus follow the assumptions defined therein.

Pipeline

Pipeline LCA data were approximated using the ecoinvent database (ecoinvent, 2022) and openLCA 2.0 (GreenDelta, 2024). The process titled "transport, pipeline, onshore, long distance, natural gas | transport, pipeline, onshore, long distance, natural gas | APOS, S - US" (wherein "APOS" stands for allocation at the point of substitution and "S" stands for system) was used as a proxy, and its 100-year global warming potential was calculated using TRACI 2.1. Thus, the lifecycle impacts of the pipeline were calculated as a function of the tonnes of CO_2 transported multiplied by the miles across which the CO_2 was transported. Due to a lack of lifecycle impact data for varying pipeline diameters in ecoinvent, pipeline diameter was assumed to have no impact on the lifecycle impacts of the pipeline. The CO_2NNECTION team will seek to address this gap in further iterations of this analysis.

Carbon Efficiency

The carbon efficiency of the intermodal transport system was calculated using Equation 1. The mass of CO_2 emitted by the system was obtained from the LCA for each scenario and sub-scenario.

$$Carbon\ efficiency\ (\%) = 100 \times \frac{mass\ of\ CO_2\ transported - mass\ of\ CO_2\ emitted}{mass\ of\ CO_2\ transported} \quad (1)$$

2.2 Assessment Results

Key results for the scenarios and sub-scenarios are presented in Table 4. Scenario 1A, which uses only pipelines for transportation, was calculated to have the lowest breakeven price of $5 per net tonne of CO_2 and the highest carbon efficiency of 98.9%. Scenario 1 was found to have the highest breakeven price of $31 per net tonne of CO_2 and the lowest carbon efficiency of 97.6%. All scenario calculations yielded a positive internal rate of return.

Table 4. Key values for scenarios and sub-scenarios

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	Breakeven Price of CO_2 ($ / net tonne)
Scenario 1	1,788,817,379	42	97.6	31
Scenario 2	2,730,985,108	42	98.4	22
Scenario 1A	2,253,521,755	105	98.9	5
Scenario 1B	2,135,004,677	73	98.5	13
Scenario 1C	1,953,336,958	53	97.9	23

2.2.1 Scenario 1

Scenario 1 (Figure C-1) gathers CO_2 from hypothetical locations of sources that currently exist in the study area, focusing on small- and medium-sized sources throughout southwestern PA, northern WV, and eastern OH. Key results for Scenario 1 are presented in Table 5.

Table 5. Key values for Scenario 1

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	CAPEX ($)	OPEX ($ / year)	Labor ($ / year)
Scenario 1	1,788,817,379	42	97.6	212,411,991	30,768,949	6,813,574

The distribution of CAPEX, OPEX, and labor costs for the overall scenario are provided in Figure 1, Figure 2, and Figure 3, respectively. Rail is the most significant contributor to both CAPEX and OPEX, whereas trucks are the most significant contributor to annual labor costs.

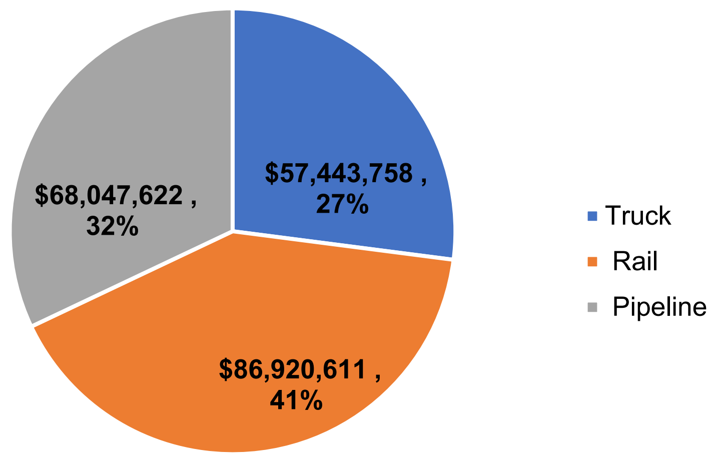

Figure 1. Distribution of CAPEX for intermodal transport system in Scenario 1

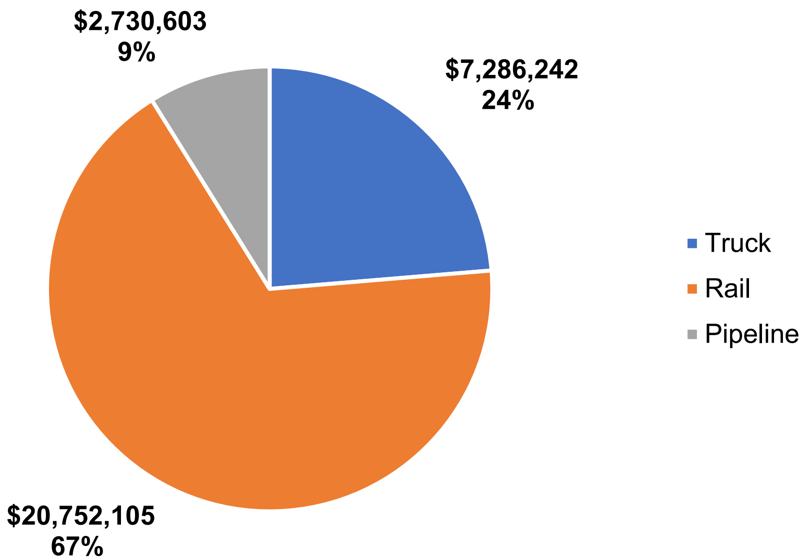

Figure 2. Distribution of OPEX for intermodal transport system in Scenario 1

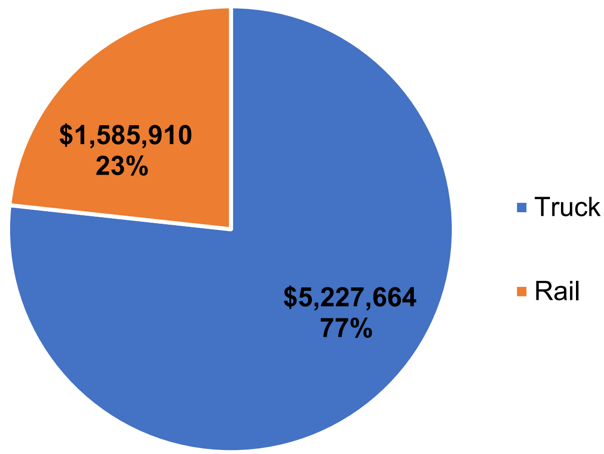

Figure 3. Distribution of labor costs for intermodal transport system in Scenario 1

Figure 4 and Figure 5 illustrate the distribution of CAPEX for the scenario's truck and rail systems. For the truck transport system, the capital cost of the trucks themselves is the most significant, consisting of 35% of the overall truck transport system CAPEX. For the rail transport system, buffer storage is the largest contributor, with upstream and downstream storage each contributing 34% and 33% to total rail CAPEX, respectively.

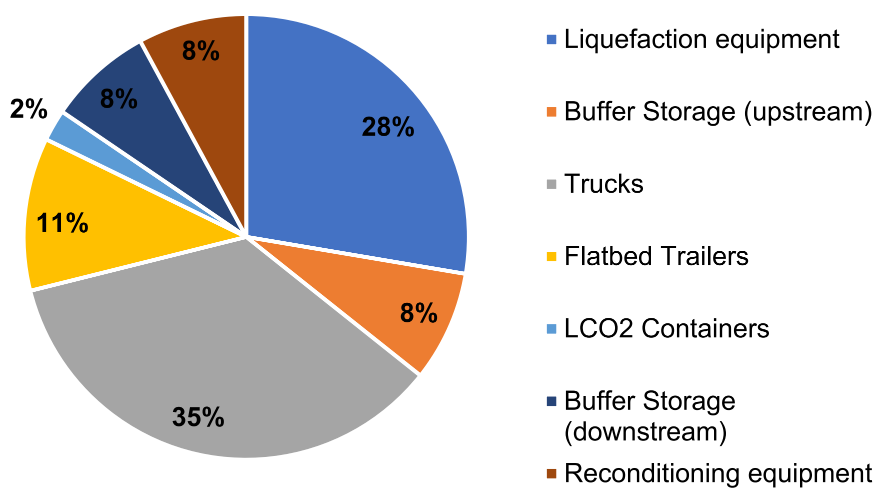

Figure 4. Distribution of CAPEX for truck transport system in Scenario 1

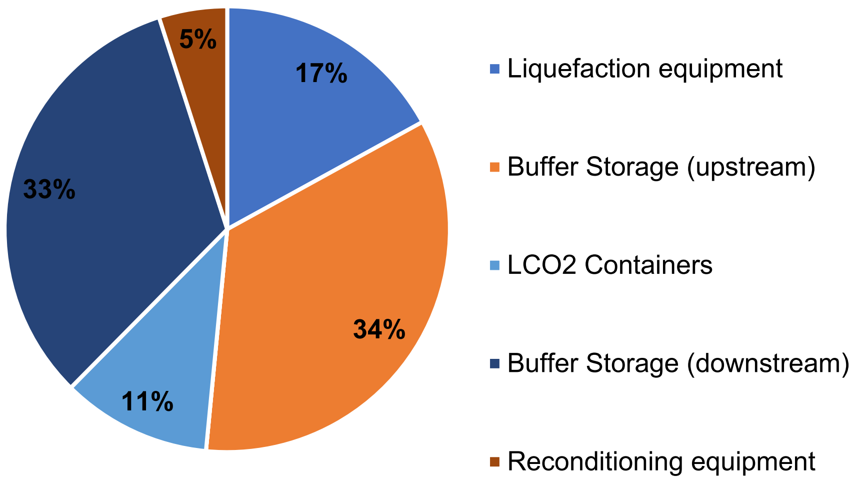

Figure 5. Distribution of CAPEX for rail transport system in Scenario 1

2.2.2 Scenario 2

Scenario 2 (Figure C-2) explores how the transport network of Scenario 1 would change with the introduction of a hydrogen plant in Doddridge County, WV. Key values for Scenario 2 are presented in Table 6.

Table 6. Key values for Scenario 2

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	CAPEX ($)	OPEX ($ / year)	Labor ($ / year)
Scenario 2	2,730,985,108	42	98.4	318,484,258	23,601,955	4,054,482

The distribution of CAPEX, OPEX, and labor costs for the overall scenario are provided in Figure 6, Figure 7, and Figure 8. Pipeline is the most significant contributor to CAPEX at 78%. Rail constitutes 44% of the scenario's OPEX, while truck contributes 78% to annual labor costs.

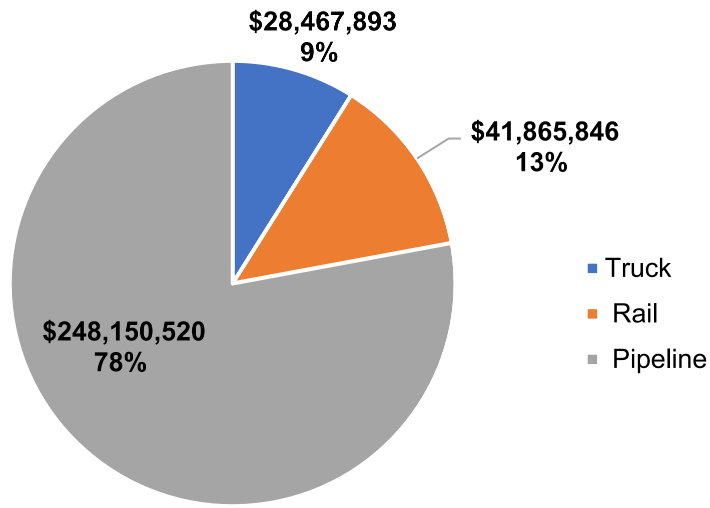

Figure 6. Distribution of CAPEX for intermodal transport system in Scenario 2

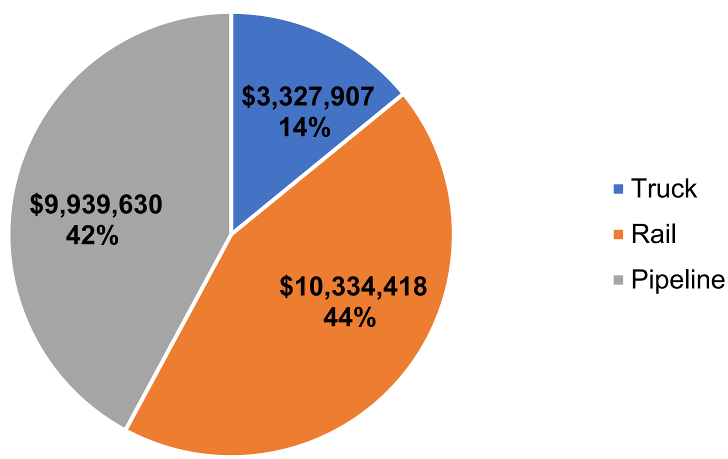

Figure 7. Distribution of OPEX for intermodal transport system in Scenario 2

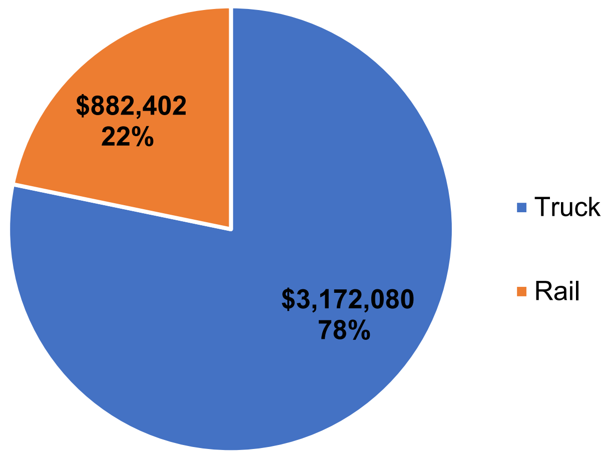

Figure 8. Distribution of labor costs for intermodal transport system in Scenario 2

Figure 9 and Figure 10 illustrate the distribution of CAPEX for the scenario's truck and rail systems. Liquefaction equipment is the most significant individual contributor to both truck and rail CAPEX. For rail, both upstream and downstream buffer storage are also significant contributors to CAPEX, contributing 27% and 26%, respectively.

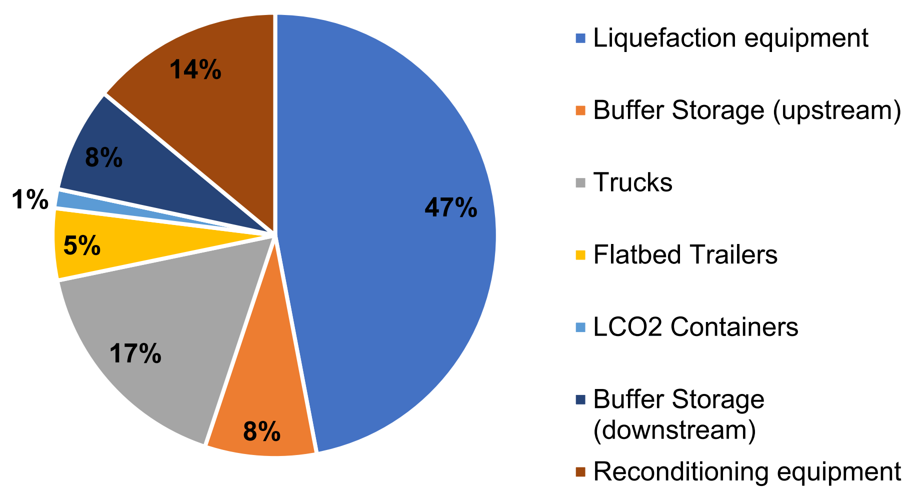

Figure 9. Distribution of CAPEX for truck transport system in Scenario 2

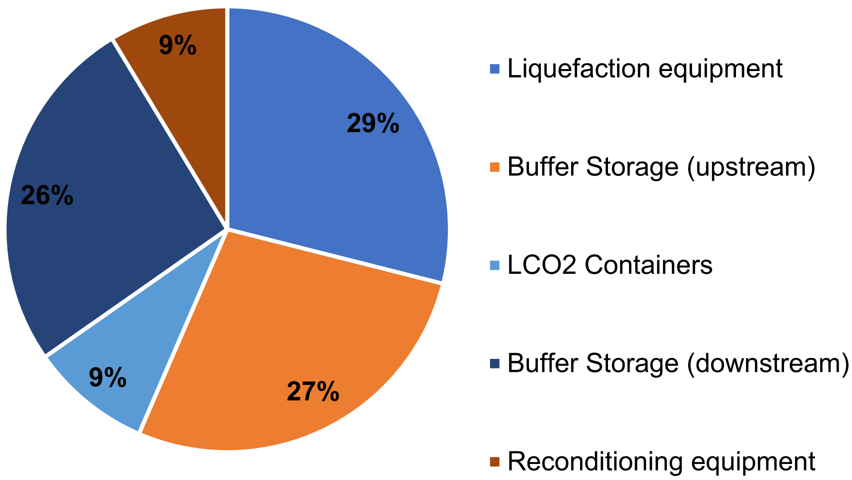

Figure 10. Distribution of CAPEX for rail transport system in Scenario 2

2.2.3 Scenario 1A - Only Pipeline

In Scenario 1A (Figure C-3), truck and rail transport routes and their associated CO_2 sources were removed from Scenario 1. Only pipelines and CO_2 sources located at pipeline hubs were considered. The key economic and LCA values resulting from this scenario are presented in Table 7. In comparison to the Scenario 1 base case, Scenario 1A has both a higher IRR and higher carbon efficiency.

Table 7. Key values for Scenario 1A

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	CAPEX ($)	OPEX ($ / year)
Scenario 1A	2,253,521,75	105	98.9	67,643,788	2,705,752

2.2.4 Scenario 1B - Fewer Trucking Connections

In Scenario 1B (Figure C-4), sources #3, 6, 7, and 8 are removed from Scenario 1. The key economic and LCA values resulting from this scenario are presented in Table 8.

Table 8. Key values for Scenario 1B

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	CAPEX ($)	OPEX ($ / year)	Labor ($ / year)
Scenario 1B	2,135,004,677	73	98.5	111,063,330	8,625,764	3,447,576

The distribution of CAPEX, OPEX, and labor costs for the overall scenario are provided in Figure 11, Figure 12, and Figure 13. Pipeline is the most significant contributor to CAPEX at 61%. Rail constitutes 48% of the scenario's OPEX, while truck contributes 74% to annual labor costs.

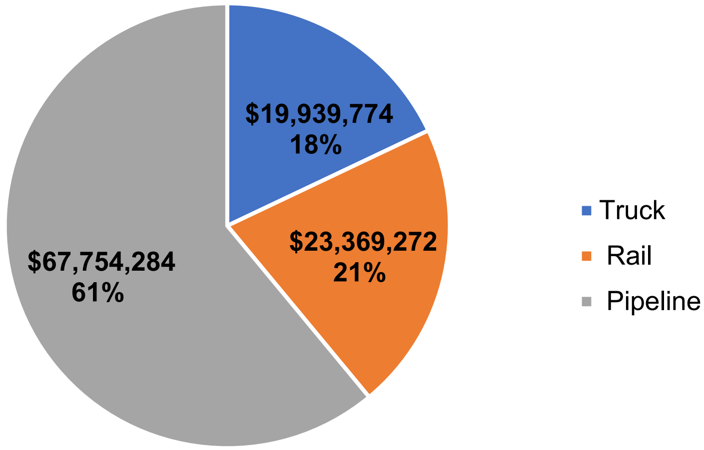

Figure 11. Distribution of CAPEX for intermodal transport system in Scenario 1B

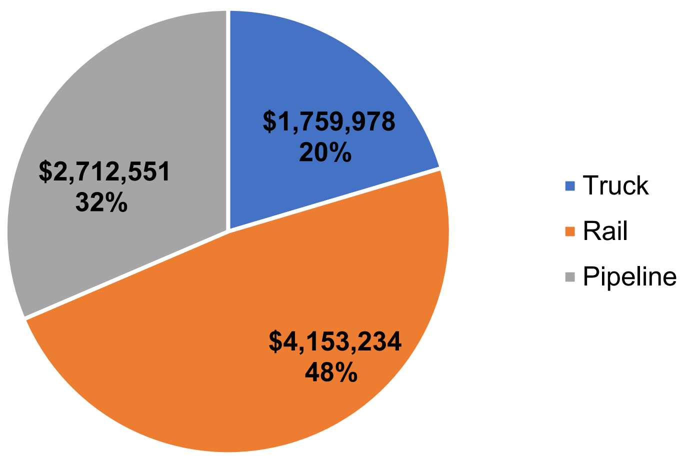

Figure 12. Distribution of OPEX for intermodal transport system in Scenario 1B

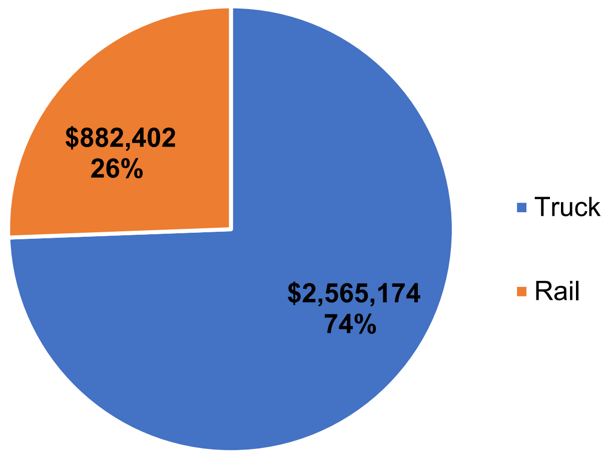

Figure 13. Distribution of labor costs for intermodal transport system in Scenario 1B

Figure 14 and Figure 15 illustrate the distribution of CAPEX for the scenario's truck and rail systems. Liquefaction equipment is the most significant individual contributor to truck CAPEX. For rail, both upstream and downstream buffer storage are also significant contributors to CAPEX, contributing 30% and 29%, respectively.

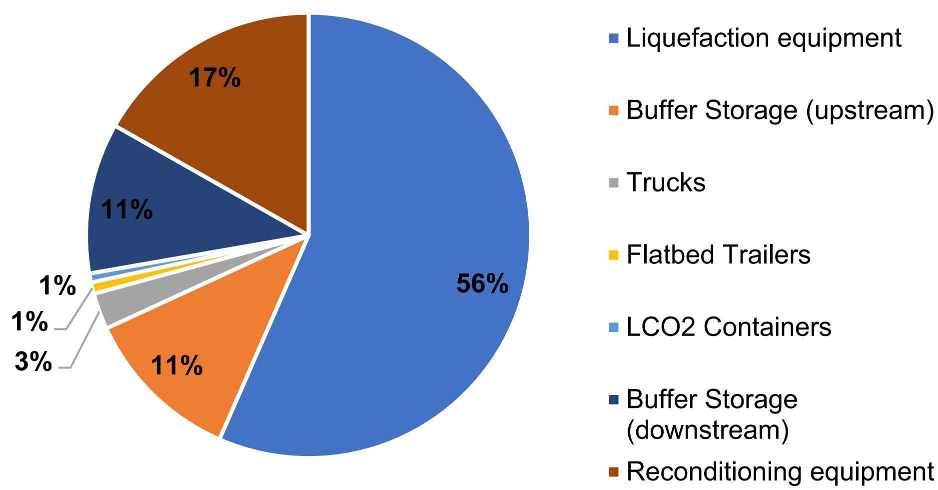

Figure 14. Distribution of CAPEX for truck transport system in Scenario 1B

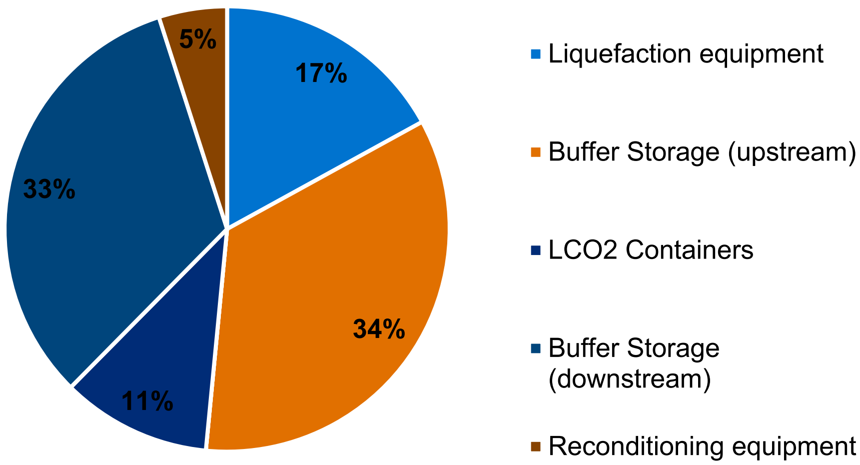

Figure 15. Distribution of CAPEX for rail transport system in Scenario 1B

2.2.5 Scenario 1C - No Railyard 3

In Scenario 1C (Figure C-5), source #6 and Railyard 3 are removed from Scenario 1. The key economic and LCA values resulting from this scenario are presented in Table 9.

Table 9. Key values for Scenario 1C

Scenario	NPV ($)	IRR (%)	Carbon Efficiency (%)	CAPEX ($)	OPEX ($ / year)	Labor ($ / year)
Scenario 1C	1,953,336,958	53	97.9	163,303,601	21,900,390	5,237,172

The distribution of CAPEX, OPEX, and labor costs for the overall scenario are provided in Figure 16, Figure 17, and Figure 18. Pipeline is the most significant contributor to CAPEX at 42%. Rail constitutes 64% of the scenario's OPEX, while truck contributes 83% to annual labor costs.

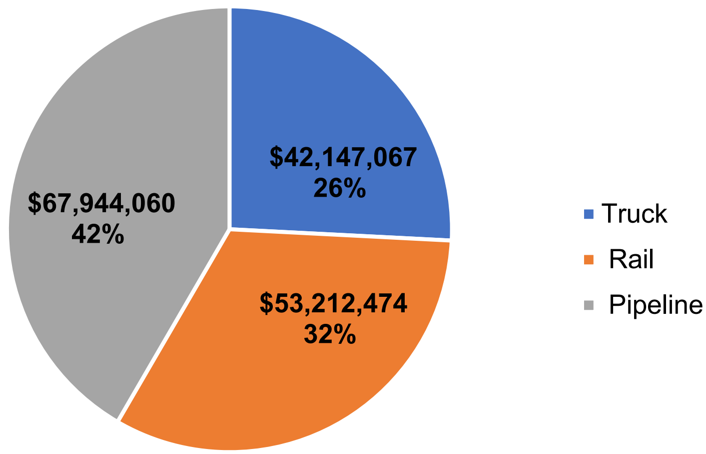

Figure 16. Distribution of CAPEX for intermodal transport system in Scenario 1C

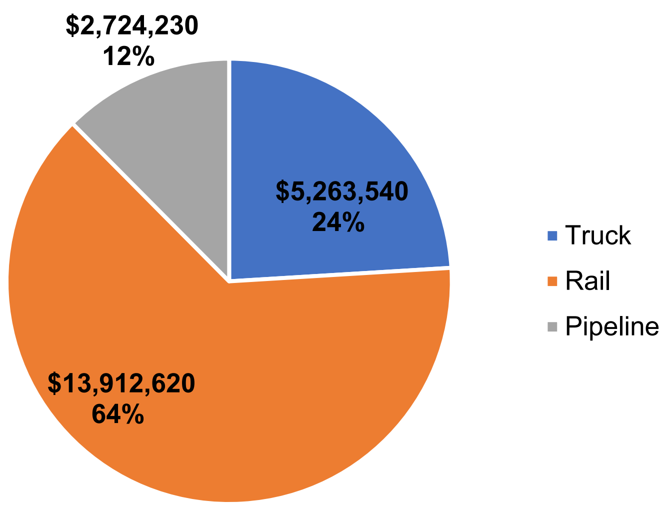

Figure 17. Distribution of OPEX for intermodal transport system in Scenario 1C

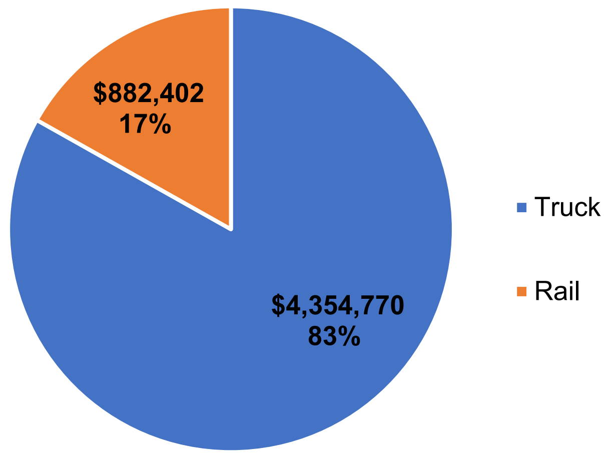

Figure 18. Distribution of labor costs for intermodal transport system in Scenario 1C

Figure 19 and Figure 20 illustrate the distribution of CAPEX for the scenario's truck and rail systems. Liquefaction equipment is the most significant individual contributor to truck CAPEX. For rail, both upstream and downstream buffer storage are also significant contributors to CAPEX, contributing 30% and 29%, respectively.

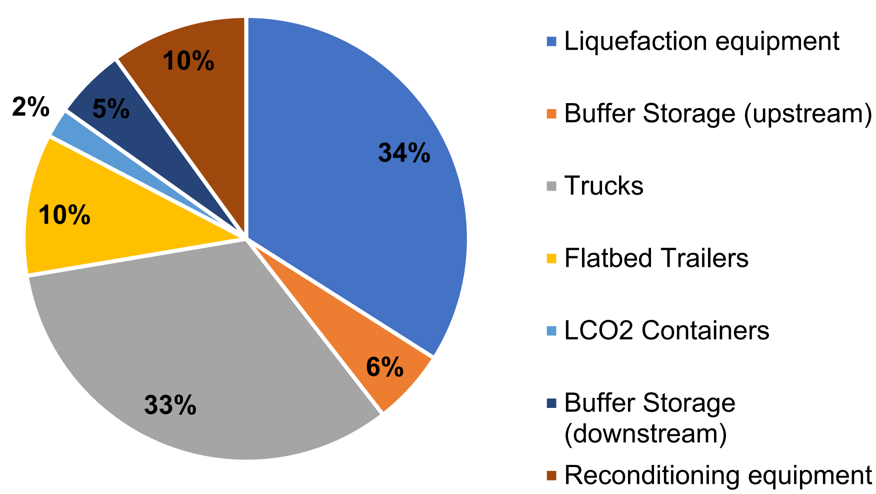

Figure 19. Distribution of CAPEX for truck transport system in Scenario 1C

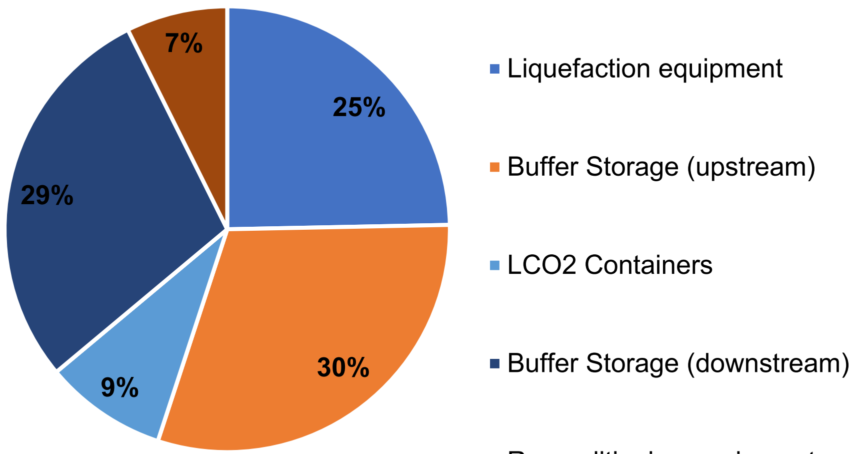

Figure 20. Distribution of CAPEX for rail transport system in Scenario 1 C

2.2 Market Analysis

The CO_2NNECTION intermodal transport network could generate revenue primarily through carbon credits in the compliance and the voluntary markets, wherein 45Q tax incentive credits could be sold to third parties. As of 2024, over 4,000 companies have committed to voluntary decarbonization targets. Many of these companies rely on carbon credit purchases as well as infrastructure investments to meet their goals. CCS credits were the fastest growing type of credit for the voluntary credit market in 2024 (Abatable, 2025). While historically many carbon credits were produced by nature-based projects, such as reforestation, there has been an industry shift towards infrastructure-based credits. For example, major carbon credit purchaser, Shell, which retired 14.5 million carbon credits in 2024, recently announced a shift away from nature-based credits (DGB Group, 2025). In 2025, carbon credits for stored CO_2 were sold for approximately $40-60 per tonne (Hispa, 2025).

Currently, the United States does not have a national carbon credit system creating a compliance market. However, state level compliance markets exist in several states (Center for Climate and Energy Solutions, 2025), including:

- California
- Oregon
- Washington
- Connecticut
- Delaware
- Maine
- Maryland
- Massachusetts
- New Hampshire
- New Jersey
- New York
- Rhode Island
- Vermont

The northeastern states (Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) are all active members of the Regional Greenhouse Gas Initiative (RGGI) (Plummer, 2025). Additionally, PA is an inactive member. The most recent auction held by the RGGI in June of 2025 sold 15,244,479 carbon allowances to 45 different bidders at an average price of $19.05 per unit, generating $299,249,122.77 in proceeds (RGGI Inc., 2025). Since 2008, the RGGI has generated $9,380,528,817.22 from carbon allowance auctions (RGGI Inc., 2025). In the June 2025 auction, 54% of allowances were purchased by entities to satisfy their compliance obligations, and 46% were believed to be purchased for resale or other investment purposes (RGGI Inc., 2025).

Companies that are capturing their own carbon to fulfill environmental promises need a reliable transportation network if they are not sequestering or utilizing the captured carbon on site. One key requirement for on-site carbon sequestration is the site being located at a geological formation with appropriate storge capacity and characteristics. Projects capturing carbon at a site that does not meet geological requirements must transport CO_2 to a suitable location. Companies may be willing to pay for transportation services to meet voluntary or regulatory environmental commitments. As a transportation project, CO_2NNECTION would not be able to receive 45Q tax credits directly, but it could instead provide a necessary service to companies seeking to qualify.

2.2.1 Potential Utilization of Tax Credits and Other Incentives

The 45Q tax incentive provides tax credits to companies that capture and store or utilize carbon that would otherwise be released into the atmosphere. Currently, the credits offer between $12 and $85 per tonne of CO_2 sequestered. These credits can either be used to offset construction and operational costs or sold at a premium to third parties. When a company decides to transfer 45Q credits to a third party, the payment is not taxable to the seller. To qualify for 45Q, a facility must begin construction before 2033. The facility can then claim the credit for up to 12 years (AccountingInsights Team, 2025). Electing to receive the 45Q credits as transferable and selling them at a premium greater than the government rate provides a significant opportunity for generating revenue.

2.2.2 Potential Financing Structures and Partnerships for Deployment of the Technology

Potential financing structures for the CO_2NNECTION intermodal transport hub include

1) traditional project financing,

2) tax equity financing, and

3) tax credit monetization.

In traditional project financing, project developers secure debt financing from banks or other financial institutions to fund a portion of the project's capital costs. The debt is typically secured by project assets and cash flows, with lenders conducting due diligence to assess the project's risks and creditworthiness.

For tax equity financing, investors, such as corporations with tax liabilities, provide upfront capital, in exchange for a share of the tax benefits generated by the project, including the 45Q tax credits. This structure allows project developers to monetize the tax credits and access additional capital to fund project development and construction.

Similar to tax equity financing, tax credit monetization project developers may also monetize the 45Q tax credits directly by selling them to third-party investors or financial institutions. This method provides immediate cash proceeds to the project developer, which can be used to fund project development or repay debt. Monetization involves the sale of tax credits at a premium to face value, reflecting the time value of money and perceived risks associated with the tax credits.

Intermodal transportation is necessary for efficient and safe transportation of CO_2 from capture to sequestration sites. While there is a significant number of carbon capture facilities either under development or currently operating on the eastern half of the United States, there are no CO_2 pipelines operating east of the Mississippi River, and only one under development in Mississippi, Louisiana, and Texas (American Carbon Alliance, 2025). As the carbon sequestration market grows, more companies will need reliable transportation for their captured CO_2. Future projects or expansions of CO_2NNECTION could partner with companies to connect their facilities with an integrated carbon transportation system based on the original CO_2NNECTION project.

2.4 Projection of Future Deployment Scenarios

In the tri-state region of OH, WV, and PA—home to a dense concentration of natural gas processing facilities, petrochemical plants, and coal-fired power stations—future deployment scenarios for CO_2 transportation are expected to evolve rapidly, assuming federal incentives continue to be offered, such as those from the 45Q tax credit and state-level decarbonization goals. In a moderate-growth scenario, CO_2 capture and transport infrastructure would expand incrementally, with early projects relying on truck and rail to move captured CO_2 to nearby injection wells, particularly in areas with limited pipeline access. This approach allows for flexible deployment while minimizing upfront capital costs. Over time, as capture volumes increase and regional hubs emerge, investment in dedicated CO_2 pipelines is projected to become more economically viable, especially along corridors connecting the Ohio River Valley to Class VI-permitted storage sites in eastern OH and western WV.

In a high-growth scenario, driven by aggressive climate policy, carbon markets, and industrial decarbonization mandates, the region could see the rapid buildout of a shared CO_2 pipeline network, similar to the development of natural gas infrastructure in the early 2000s. This would enable economies of scale and interconnectivity between emitters and storage operators, supporting the transport of tens of millions of tonnes of CO_2 annually. Strategic deployment would likely prioritize clusters such as the Appalachian Basin, where geological storage potential aligns with high-emission industrial zones. Scenario modeling would also account for permitting timelines, public acceptance, and workforce readiness, all of which could influence the pace and feasibility of deployment. These projections help stakeholders anticipate infrastructure needs, investment timing, and policy support mechanisms required to scale CCS in the region effectively.

2.5 Quantification of Potential Benefits of Technology Implementation

In 2024, there were 45 facilities globally applying carbon capture, utilization, and storage. These facilities had a combined carbon capture capacity of 50 million tonnes per year; however, to achieve the net zero emissions (NZE) scenario by 2050, 1,300 million tonnes of CO_2 will need to be captured annually by 2050 (International Energy Agency [IEA], 2024). It is estimated that approximately 1,178 million tonnes of CO_2 will be produced by U.S. industry in 2040 (EIA, 2024). A technoeconomic analysis of the CO_2NNECTION project demonstrated the intermodal transport network's capability of transporting up to 1,630 net kilotonnes of CO_2 per year in Scenarios 1 or 2,135 net kilotonnes of CO_2 per year in Scenario 2. These capacities correspond to 0.14% and 0.18% of the CO_2 estimated to be produced by United States industry in 2040.

A major pipeline project such as CO_2NNECTION could employ over 500 construction workers for the installation of approximately 100 miles of pipeline alone (Liquid Energy Pipeline Association, 2025a, 2025b). Pipelayers make on average $30.51 per hour, while the national average pay for construction workers is $19.50 per hour in 2025 (Payscale Inc., 2025). This is over a 60% pay increase for workers who transition to become pipelayers. Net-Zero America estimates that over 100,000 kilometers or 62,000 miles of CO_2 pipelines could be needed in the US by 2050 to achieve net zero emissions (Larson et al., 2021). Using this assumption, the Net-Zero America scenario would require up to 310,000 construction jobs to complete. In 2024, there were roughly 8.2 million individuals employed in the construction industry, so installing the pipeline needed for the NZE scenario could increase construction employment by up to 3.8% (Jones, 2025). In addition to construction jobs, pipeline installation projects generate hundreds of professional service and management jobs for engineers, architects, and contractors.

3.0 Summary, Conclusions, and Next Steps

This document summarizes the BCA completed as part of the CO_2NNECTION project, which evaluates the economic and logistical feasibility of transporting captured CO_2 from point-source emitters to injection wells for permanent geologic storage. The geographic focus of the project is the tri-state region of OH, WV, and PA, which is an area with significant CO_2 emissions and promising subsurface storage potential. The intended application of this BCA is to understand the business case for implementing the intermodal CO_2 transport hub.

First, the process to quantify operating costs; revenues; cash flows; earnings before interest, taxes, depreciation, and amortization; tax credits and liabilities; and project return on investment was outlined. The methodology and technoeconomic assessment results were followed by discussions on market analysis, projection of future deployment scenarios, and quantification of the potential benefits of technology implementation. Particular attention was paid to applying 45Q credits to the project's costs. Based on the results of the economic assessment, the following conclusions were drawn:

1. All scenarios show economic viability when supported by the 45Q tax credit.
2. It is anticipated that the majority of capital costs would be incurred at the capture and/or injection sites, not by the transportation network itself.
3. The scenario with the lowest identified breakeven cost, Scenario 1A, only utilizes pipeline as a transportation method. This outcome is reasonable based on CO_2 transport literature (McCoy and Rubin, 2008).
4. Truck and rail are viable transportation methods for smaller carbon sources, but their implementation needs to be balanced by considering their impacts to the overall transportation project.

To further develop this BCA, two key next steps were identified:

1. Refining pipeline cost estimates
2. Identifying areas for cost optimization across the transport network

Acquiring more recent and region-specific data for pipeline cost estimates would improve the quality of the economic assessment and BCA. The economic models for pipelines implemented in the current analysis, although robust, are becoming outdated and do not necessarily reflect recent technological advances or information specific to the CO_2NNECTION project. Additionally, these general models rely on national averages or outdated figures, which may not reflect the unique terrain, permitting environment, and labor costs in the Appalachian region today. In particular, the evaluated scenarios would benefit from sub-awardee TRC Companies, Inc. (TRC)'s expertise in pipeline modeling and costing. The information TRC provides will be considered as an alternative approach, and the results from implementing this approach will be compared to the current analysis to determine impacts to project CAPEX and OPEX.

Another important step will be identifying areas for cost optimization across the proposed transportation network. This step would include tasks such as 1) evaluating economies of scale in pipeline diameter selection, 2) identifying opportunities for co-location with existing rights of way, and 3) researching potential for shared infrastructure among emitters. Furthermore, benchmarking CO_2NNECTION against comparable recent projects would highlight aspects of CO_2NNECTION that can be further refined to maximize the project's benefit.

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U.S. Energy Information Administration (EIA). 2024. Annual Energy Outlook 2025 - Table 18. Energy-Related Carbon Dioxide Emissions by Sector and Source.

Appendix A: Long-Lead Material and Equipment List

The CO_2NNECTION project evaluates the economic and logistical feasibility of an integrated intermodal CO_2 transportation system that collects CO_2 emissions from sources in OH, PA, and WV and transports them via pipeline, rail, and truck to injection wells for geological sequestration. The transportation system requires a wide range of equipment and materials, many of which have long lead times (≥ six months) for delivery. Table A - 1 identifies equipment and materials with long lead times, the location or mode where the equipment is required, the purpose of the equipment, and the anticipated lead time. It is pertinent to note that permitting requirements for the various intermodal facilities and the acquisition of right-of-way for the pipelines will take several years.

Table A - 1. Long-lead material and equipment list for the CO_2NNECTION project

Item	Modes or Locations Requiring	Purpose	Lead Time
CO_2 conditioning equipment	Class VI well, CO_2 emission sources	Equipment to compress, dehydrate, and clean up CO_2 to meet pipeline or injection well specifications	12-18 months
Circuit breakers and switchgear	Substations servicing various intermodal operations	Control, protect, and isolate electrical circuits within the substation	6-12 months
Compressor/pump stations	Pipeline	Maintain CO_2 pressure and flow in pipeline	12-18 months
Cryogenic or pressurized tanks	Any location requiring CO_2 storage or buffering capacity	Storage of CO_2 at transfer locations.	6-12 months
Drilling rig and equipment	Class VI well	Construction of the Class VI well	6-12 months to schedule the drill rig use
Fittings and flanges	Pipeline, truck, rail	Connection of pipeline or piping components	6-8 months
Liquefaction and vaporization equipment	Truck, rail	Liquefaction of pipeline CO_2 for truck or rail transport. Vaporization of CO_2 from truck or rail tanks to pipelines	12-24 months
Metering and regulating stations	Pipeline	Measure and control CO_2 flow and pressure in the pipeline	8-12 months
Monitoring and testing equipment	Class VI well	Equipment for monitoring well integrity, CO_2 plume migration, and environmental impacts	6-12 months
Pipe and coatings, 8", 12", 18", 24"	Pipeline, truck, rail	Transport of CO_2 over long distances as well as at intermodal operation facilities	6-18 months, depending on size, grade, and coating requirements
Supervisory Control and Data Acquisition (SCADA) systems	All	Supports remote monitoring and control of the various intermodal operations	6-12 months
Transformers	Substations servicing various intermodal operations	Step up/down voltage for efficient transmission, distribution, and use	12-24 months
Valves (block, check, control)	Pipeline, truck, rail	Regulation of pipeline flow	6-15 months
Well casing and tubing	Class VI well	Casing and tubing to line the Class VI wellbore and provide structural integrity	6-9 months
Wellhead and injection equipment	Class VI well	Class VI wellhead assembly and injection control	6-12 months

Appendix B: Economic Assumptions

Table B-1. DCF assumptions for all scenarios and sub-scenarios

Parameter	Value	Notes / Source
Cost of debt	6%	Assumption - Battelle Subject Matter Expert (SME)
Cost of equity	20%	Internal rate of return on equity Assumption - Battelle SME
Depreciation schedule	20 years, 150% declining balance	Assumption - Battelle SME
Project life (years)	30	
State income tax rate	6%	
Federal income tax rate	21%	25.740 % Effective Rate; Assumption - Battelle SME
Debt term	10 Years	Assumption - Battelle SME
CAPEX period	1-3 years	
Overnight capital distribution	10%, 60%, 30%	
Escalation during CAPEX period	3.60%	
Working capital	0	
Escalation during operation	3%	
Debt/equity split	50%	
WACC	13.00%	
Salvage value	5%	

Table B-2. Depreciation and debt calculations for Scenario 1

Operating Yr	-3	-2	-1	1	2	3
Project Yr	1	2	3	4	5	6
CAPEX	$ 21,241,199	$ 132,035,294	$ 68,394,282			
Beginning book value	$ -	$ 21,241,199	$ 153,276,493	$ 221,670,775	$ 205,045,467	$ 188,857,667
Depreciation	$ -	$ -	$ -	$ 16,625,308	$ 16,187,800	$ 15,738,139
Ending book value	$ 21,241,199	$ 153,276,493	$ 221,670,775	$ 205,045,467	$ 188,857,667	$ 173,119,528
Debt						
Beginning debt balance	$ -	$ 10,620,600	$ 76,638,247	$ 110,835,388	$ 102,426,533	$ 93,513,147
Additional debt	$ 10,620,600	$ 66,017,647	$ 34,197,141			
Principal payment	$ -	$ -	$ -	$ 8,408,855	$ 8,913,386	$ 9,448,189
Ending debt balance	$ 10,620,600	$ 76,638,247	$ 110,835,388	$ 102,426,533	$ 93,513,147	$ 84,064,958
Interest payment	$ -	$ 637,236	$ 4,598,295	$ 6,650,123	$ 6,145,592	$ 5,610,789

Salvage value	$11,083,539

Operating Yr	4	5	6	7	8	9	10
Project Yr	7	8	9	10	11	12	13
CAPEX	$ 173,119,528	$ 157,844,276	$ 143,046,375	$ 128,741,737	$114,947,980	$101,684,751	$88,974,157
Beginning book value	$ 15,275,252	$ 14,797,901	$ 14,304,637	$ 13,793,758	$ 13,263,228	$ 12,710,594	$12,132,840
Depreciation	$ 157,844,276	$ 143,046,375	$ 128,741,737	$ 114,947,980	$101,684,751	$ 88,974,157	$76,841,318
Ending book value							
Debt							
Beginning debt balance	$ 84,064,958	$ 74,049,878	$ 63,433,893	$ 52,180,949	$ 40,252,828	$ 27,609,019	$14,206,583
Additional debt							
Principal payment	$ 10,015,080	$ 10,615,985	$ 11,252,944	$ 11,928,121	$ 12,643,808	$ 13,402,437	$14,206,583
Ending debt balance	$ 74,049,878	$ 63,433,893	$ 52,180,949	$ 40,252,828	$ 27,609,019	$ 14,206,583	$ (0)
Interest payment	$ 5,043,897	$ 4,442,993	$ 3,806,034	$ 3,130,857	$ 2,415,170	$ 1,656,541	$ 852,395

Table B-3 (continued). Depreciation and debt calculations for Scenario 1

Operating Yr	11	12	13	14	15	16	17
Project Yr	14	15	16	17	18	19	20
Beginning book value	$ 76,841,318	$ 65,315,120	$ 54,429,267	$ 44,223,779	$ 34,747,255	$ 26,060,441	$18,242,309
Depreciation	$ 11,526,198	$ 10,885,853	$ 10,205,488	$ 9,476,524	$ 8,686,814	$ 7,818,132	$ 6,840,866
Ending book value	$ 65,315,120	$ 54,429,267	$ 44,223,779	$ 34,747,255	$ 26,060,441	$ 18,242,309	$11,401,443

Operating Yr	18	19	20	21	22	23	24
Project Yr	21	22	23	24	25	26	27
Beginning book value	$11,401,443	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539
Depreciation	$ 317,904	$ -	$ -	$ -	$ -	$ -	$ -
Ending book value	$11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539

Operating Yr	25	26	27	28	29	30
Project Yr	28	29	30	31	32	33
Beginning book value	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539
Depreciation	$ -	$ -	$ -	$ -	$ -	$ -
Ending book value	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539	$ 11,083,539

Table B-4. DCF calculations for Scenario 1

Year	1	2	3	4	5	6
CAPEX	$ (21,241,199)	$ (132,035,294)	$ (68,394,282)			
Revenues (esc 3%)	$0	$0	$0	$138,539,088	$142,695,261	$146,976,119
Variable costs (esc 3%)	$0	$0	$0	$30,768,949	$31,692,018	$32,642,778
Fixed & labor costs (esc 3%)	$0	$0	$0	$6,813,574	$7,017,981	$7,228,520
EBITDA	$0	$0	$0	$100,956,565	$103,985,262	$107,104,820
Depreciation	$0	$0	$0	($16,625,308)	($16,187,800)	($15,738,139)
EBIT	$0	$0	$0	$84,331,257	$87,797,462	$91,366,681
Interest expense	$0	($637,236)	($4,598,295)	($6,650,123)	($6,145,592)	($5,610,789)
EBT	$0	($637,236)	($4,598,295)	$77,681,134	$81,651,870	$85,755,893
Taxes	$0	$0	$0	$19,995,124	$21,017,191	$22,073,567
Depreciation add back	$0	$0	$0	$16,625,308	$16,187,800	$15,738,139
CAPEX	($21,241,199)	($132,035,294)	($68,394,282)	$0	$0	$0
Cashflow	($21,241,199)	($132,672,530)	($72,992,577)	$114,301,566	$118,856,862	$123,567,598
Discounted cash flow	($20,038,867)	($118,078,079)	($61,285,975)	$90,537,546	$88,816,761	$87,110,281

NPV	$ 1,788,817,379
IRR	42%

Table B-5 (continued). DCF calculations for Scenario 1

Year	7	8	9	10	11	12	13
Revenues (esc 3%)	$151,385,402	$155,926,964	$160,604,773	$165,422,916	$170,385,604	$175,497,172	$180,762,087
Variable costs (esc 3%)	$33,622,061	$34,630,723	$35,669,645	$36,739,734	$37,841,926	$38,977,184	$40,146,500
Fixed & labor costs (esc 3%)	$7,445,376	$7,668,737	$7,898,799	$8,135,763	$8,379,836	$8,631,231	$8,890,168
EBITDA	$110,317,965	$113,627,504	$117,036,329	$120,547,419	$124,163,841	$127,888,757	$131,725,419
Depreciation	($15,275,252)	($14,797,901)	($14,304,637)	($13,793,758)	($13,263,228)	($12,710,594)	($12,132,840)
EBIT	$95,042,712	$98,829,603	$102,731,691	$106,753,661	$110,900,613	$115,178,163	$119,592,580
Interest expense	($5,043,897)	($4,442,993)	($3,806,034)	($3,130,857)	($2,415,170)	($1,656,541)	($852,395)
EBT	$89,998,815	$94,386,610	$98,925,658	$103,622,804	$108,485,443	$113,521,622	$118,740,185
Taxes	$23,165,695	$24,295,113	$25,463,464	$26,672,510	$27,924,153	$29,220,465	$30,563,724
Depreciation add back	$15,275,252	$14,797,901	$14,304,637	$13,793,758	$13,263,228	$12,710,594	$12,132,840
CAPEX	$0	$0	$0	$0	$0	$0	$0
Cashflow	$128,439,762	$133,479,625	$138,693,760	$144,089,072	$149,672,825	$155,452,681	$161,436,748
Discounted cash flow	$85,419,778	$83,746,768	$82,092,623	$80,458,585	$78,845,777	$77,255,220	$75,687,847

Year	14	15	16	17	18	19	20
Revenues (esc 3%)	$186,184,950	$191,770,498	$197,523,613	$203,449,322	$209,552,801	$215,839,385	$222,314,567
Variable costs (esc 3%)	$41,350,895	$42,591,422	$43,869,164	$45,185,239	$46,540,796	$47,937,020	$49,375,131
Fixed & labor costs (esc 3%)	$9,156,873	$9,431,579	$9,714,527	$10,005,963	$10,306,141	$10,615,326	$10,933,785
EBITDA	$135,677,182	$139,747,497	$143,939,922	$148,258,120	$152,705,864	$157,287,039	$162,005,651
Depreciation	($11,526,198)	($10,885,853)	($10,205,488)	($9,476,524)	($8,686,814)	($7,818,132)	($6,840,866)
EBIT	$124,150,984	$128,861,644	$133,734,435	$138,781,596	$144,019,050	$149,468,907	$155,164,785
Interest expense	$0	$0	$0	$0	$0	$0	$0
EBT	$124,150,984	$128,861,644	$133,734,435	$138,781,596	$144,019,050	$149,468,907	$155,164,785
Taxes	$31,956,463	$33,168,987	$34,423,244	$35,722,383	$37,070,503	$38,473,297	$39,939,416
Depreciation add back	$11,526,198	$10,885,853	$10,205,488	$9,476,524	$8,686,814	$7,818,132	$6,840,866
CAPEX	$0	$0	$0	$0	$0	$0	$0
Cashflow	$167,633,645	$172,916,485	$178,363,166	$183,980,503	$189,776,367	$195,760,336	$201,945,066
Discounted cash flow	$74,144,523	$72,152,007	$70,211,997	$68,323,812	$66,486,972	$64,701,338	$62,967,426

Table B-6 (continued). DCF calculations for Scenario 1

Year	21	22	23	24	25	26	27
Revenues (esc 3%)	$228,984,004	$235,853,524	$242,929,130	$250,217,004	$257,723,514	$265,455,219	$273,418,876
Variable costs (esc 3%)	$50,856,385	$52,382,076	$53,953,538	$55,572,145	$57,239,309	$58,956,488	$60,725,183
Fixed & labor costs (esc 3%)	$11,261,799	$11,599,653	$11,947,643	$12,306,072	$12,675,254	$13,055,512	$13,447,177
EBITDA	$166,865,820	$171,871,795	$177,027,949	$182,338,787	$187,808,951	$193,443,219	$199,246,516
Depreciation	($317,904)	$0	$0	$0	$0	$0	$0
EBIT	$166,547,916	$171,871,795	$177,027,949	$182,338,787	$187,808,951	$193,443,219	$199,246,516
Interest expense	$0	$0	$0	$0	$0	$0	$0
EBT	$166,547,916	$171,871,795	$177,027,949	$182,338,787	$187,808,951	$193,443,219	$199,246,516
Taxes	$42,869,434	$44,239,800	$45,566,994	$46,934,004	$48,342,024	$49,792,285	$51,286,053
Depreciation add back	$317,904	$0	$0	$0	$0	$0	$0
CAPEX	$0	$0	$0	$0	$0	$0	$0
Cashflow	$209,735,254	$216,111,595	$222,594,943	$229,272,791	$236,150,975	$243,235,504	$250,532,569
Discounted cash flow	$61,694,758	$59,972,069	$58,274,746	$56,625,461	$55,022,854	$53,465,603	$51,952,426

Year	28	29	30	31	32	33
Revenues (esc 3%)	$281,621,442	$290,070,085	$298,772,188	$307,735,353	$316,967,414	$326,476,436
Variable costs (esc 3%)	$62,546,938	$64,423,347	$66,356,047	$68,346,728	$70,397,130	$72,509,044
Fixed & labor costs (esc 3%)	$13,850,592	$14,266,110	$14,694,093	$15,134,916	$15,588,964	$16,056,633
EBITDA	$205,223,911	$211,380,629	$217,722,047	$224,253,709	$230,981,320	$237,910,760
Depreciation	$0	$0	$0	$0	$0	$0
EBIT	$205,223,911	$211,380,629	$217,722,047	$224,253,709	$230,981,320	$237,910,760
Interest expense	$0	$0	$0	$0	$0	$0
EBT	$205,223,911	$211,380,629	$217,722,047	$224,253,709	$230,981,320	$237,910,760
Taxes	$52,824,635	$54,409,374	$56,041,655	$57,722,905	$59,454,592	$61,238,230
Depreciation add back	$0	$0	$0	$0	$0	$0
CAPEX	$0	$0	$0	$0	$0	$0
Cashflow	$258,048,546	$265,790,002	$273,763,702	$281,976,614	$290,435,912	$299,148,989
Discounted cash flow	$50,482,074	$49,053,336	$47,665,034	$46,316,024	$45,005,193	$43,731,461

Table B-7. Inputs for truck technoeconomic and lifecycle assessments for Scenario 1

User Inputs	
Size (kt-CO2/y)	270
Distance (mi)	140
Geographical Scale	Regional
Location	East
Transport Mode	Truck
Container Type	Intermodal
Rail Transit Time Method	NA
Rail Transit Time (h)	NA
Truck Long Haul Solution	Intermediate Storage
Buffer Storage Estimate Method	Calculated
Buffer Storage Time (h)	3
Include Liquefaction Costs?	Yes
Include Reconditioning Costs?	Yes
Electricity Source	Grid
Grid Decarbonization Pathway	Linear Reduction
Grid Net Zero Year	2050
GHG accounting	CO2e
Fuel Economy Pathway	Historical Trends
Negotiated Rail 'Base Rate' Reduction	NA
Water content (ppm-mol)	500
CO2 Pressure (bar)	15
Operating Period (y)	30
Construction Period (y)	2
Construction Start Year	2024
FINEX Parameters	Calculated
IRR	8.00%
Depreciation Period (y)	10
Capitalization (% equity)	45%
Cost of equity (IRROE)	10.75%
Cost of debt (interest rate)	4.00%
Project Contingency Factor	10.0%

Table B-8. Inputs for rail technoeconomic and lifecycle assessments for Scenario 1

User Inputs	
Size (kt-CO2/y)	220
Distance (mi)	225
Geographical Scale	Regional
Location	East
Transport Mode	Rail
Container Type	Intermodal
Rail Transit Time Method	Calculated
Rail Transit Time (h)	Select
Truck Long Haul Solution	NA
Buffer Storage Estimate Method	Calculated
Buffer Storage Time (h)	3
Include Liquefaction Costs?	Yes
Include Reconditioning Costs?	Yes
Electricity Source	Grid
Grid Decarbonization Pathway	Linear Reduction
Grid Net Zero Year	2050
GHG accounting	CO2e
Fuel Economy Pathway	Historical Trends
Negotiated Rail 'Base Rate' Reduction	0%
Water content (ppm-mol)	500
CO2 Pressure (bar)	15
Operating Period (y)	30
Construction Period (y)	2
Construction Start Year	2024
FINEX Parameters	Calculated
IRR	8.00%
Depreciation Period (y)	10
Capitalization (% equity)	45%
Cost of equity (IRROE)	10.75%
Cost of debt (interest rate)	4.00%
Project Contingency Factor	10.0%

Table B-9. Inputs for pipeline technoeconomic and lifecycle assessments for Scenario 1

Category	Parameter	Value	Units	Source
LCA	Emissions	0.056	kg CO2-eq / (tonne CO_2 * mile)	(ecoinvent 2022; GreenDelta 2024)
	Carbon efficiency	99.6%	-	-
8" diameter pipeline	Cost per distance	386,671	$ / km	(McCollum and Ogden 2006)
	CAPEX	23,556,241	$	2022 dollars
	Labor	-	$ / year	Assumed 0% of CAPEX
	OPEX	942,250	$ / year	Assumed 4% of CAPEX
12" diameter pipeline	Cost per distance	339,434	$ / km	(McCollum and Ogden 2006)
	CAPEX	44,087,547	$	2022 dollars
	Labor	-	$ / year	Assumed 0% of CAPEX
	OPEX	1,763,502	$ / year	Assumed 4% of CAPEX
Pumping truck/rail CO_2 to pipeline	% of total CO_2	9.2%	-	
	CAPEX	403,834	$	10% of pipeline CAPEX (Morgan and Shih 2024)
	OPEX	24,851	$ / year	10% of pipeline OPEX (Morgan and Shih 2024)
Total for pipelines	CAPEX	68,047,622	$	-
	Labor	-	$ / year	-
	OPEX	2,730,603	$ / year	-

Appendix C: Scenario Maps

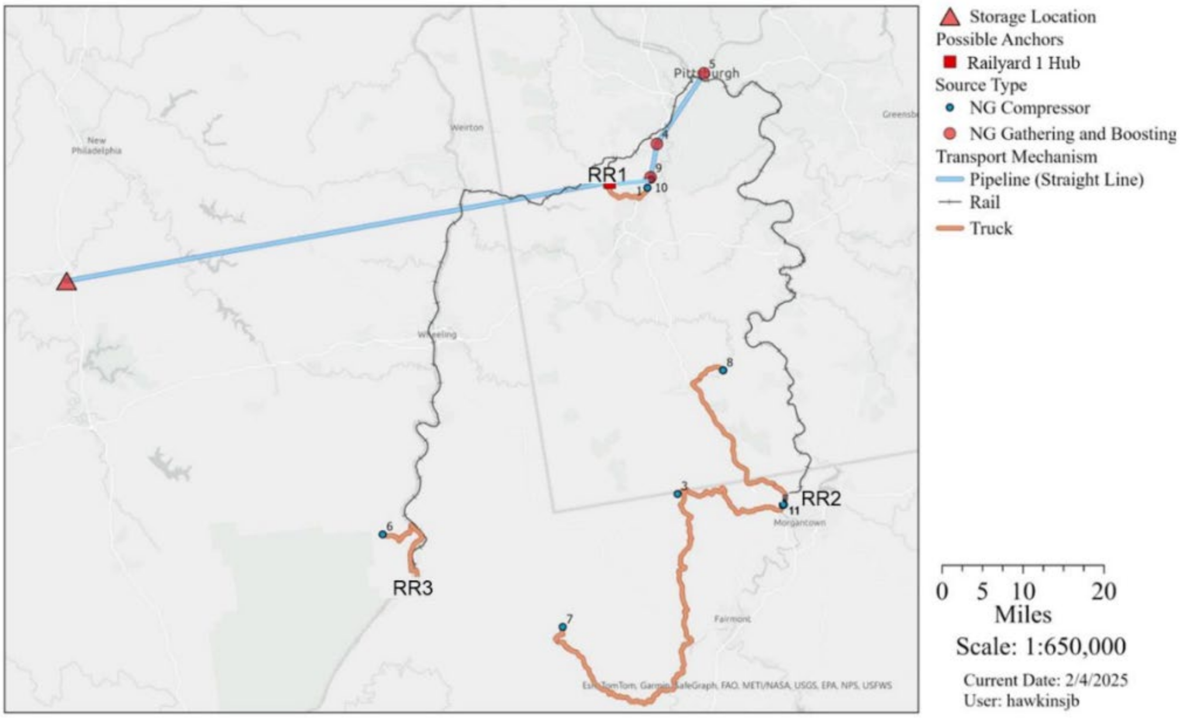

Figure C - 1. Map of Scenario 1

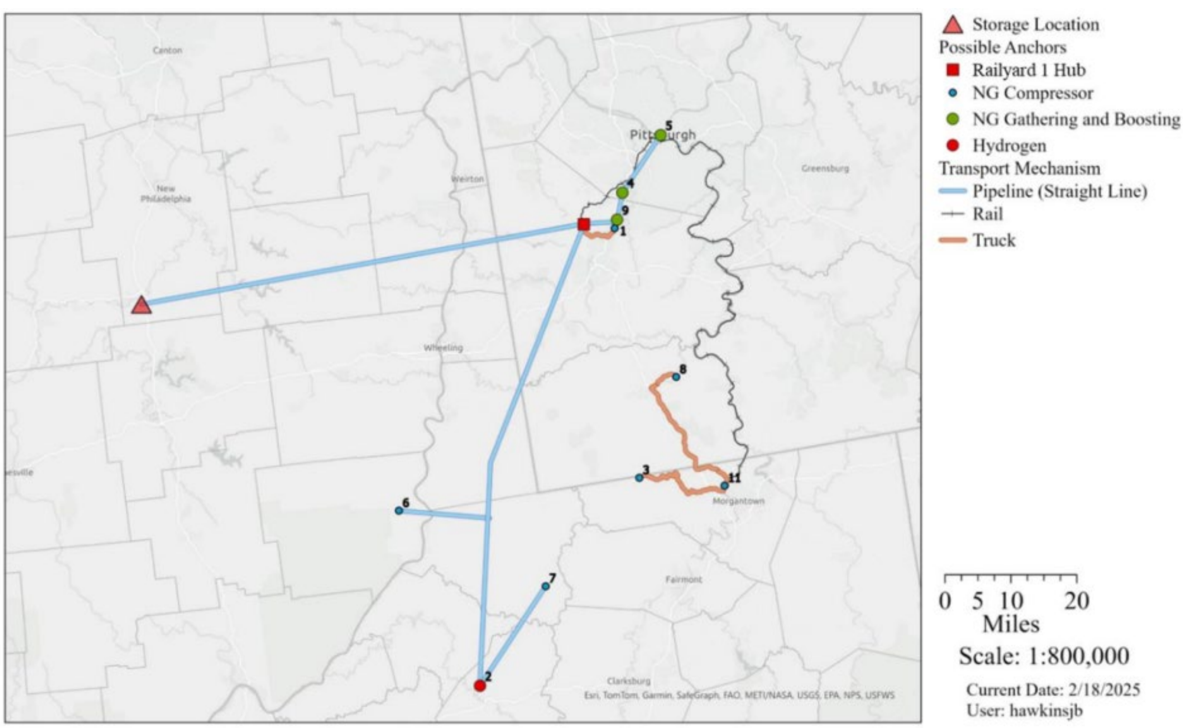

Figure C - 2. Map of Scenario 2

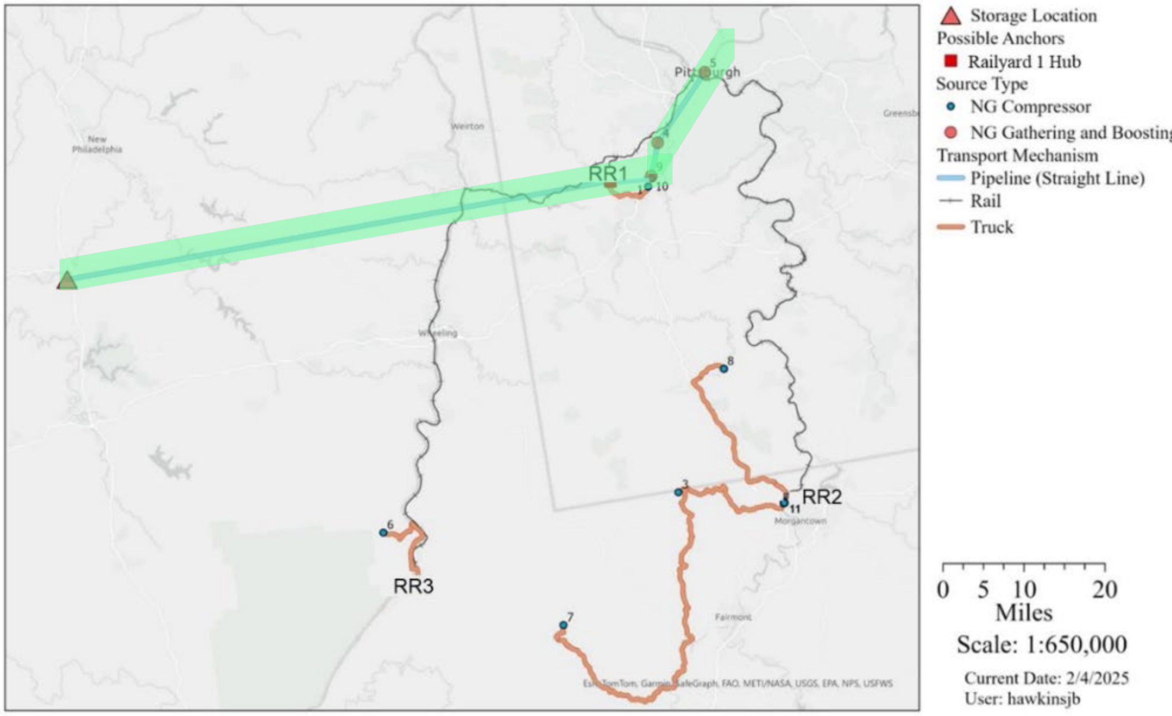

Figure C - 3. Map of Scenario 1A. This scenario includes pipeline routes and their associated CO_2 sources (shown with green highlight) but excludes all other CO_2 sources and methods of transportation described in Scenario 1.

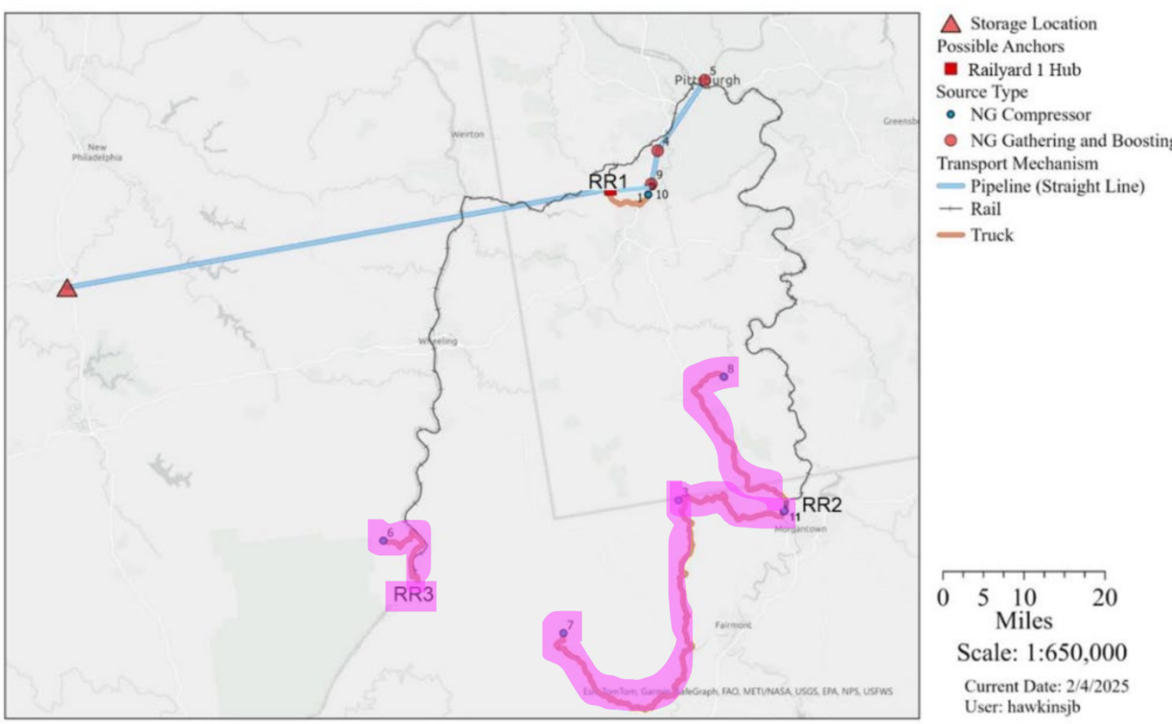

Figure C - 4. Map of Scenario 1B. This scenario excludes some trucking connections and associated sources (excluded sources and connections are highlighted in pink) but is otherwise identical to Scenario 1.

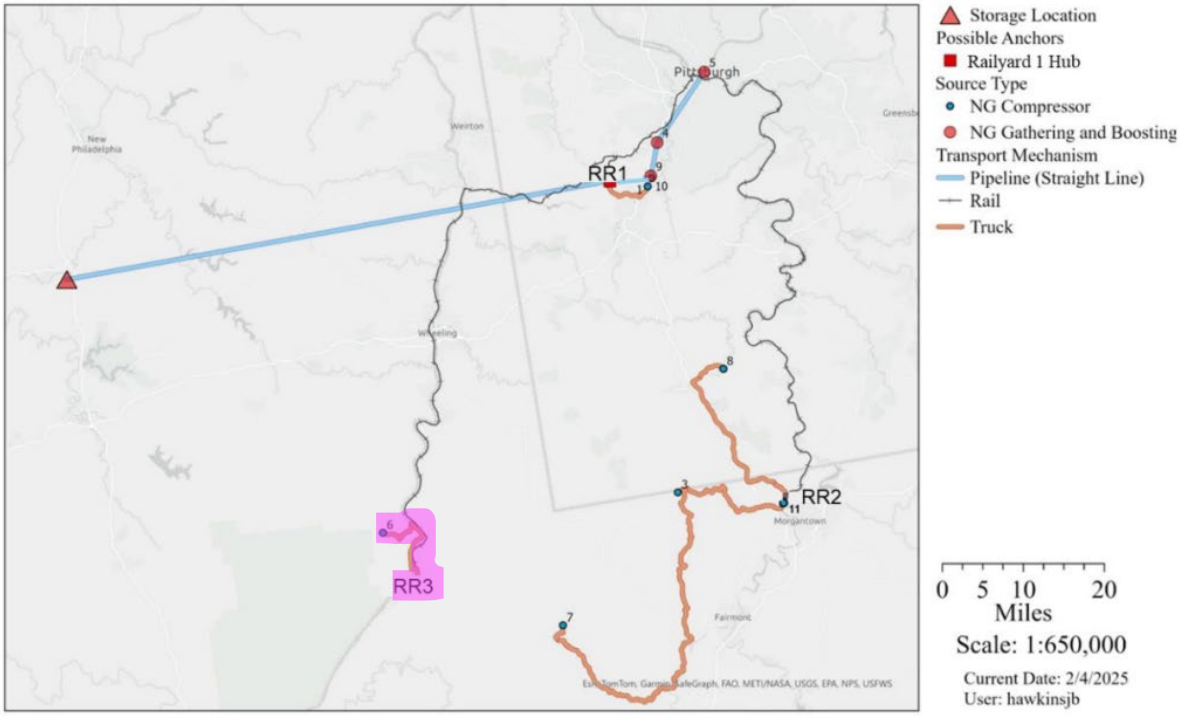

Figure C - 5. Map of Scenario 1C. This scenario excludes NG Compressor C and Railyard 3 connections (excluded source and connection are highlighted in pink) but is otherwise identical to Scenario 1.

Appendix 3. Hazard Identification (HAZID) Preliminary Summary

DE-FE0032487

Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION)

Hazard Identification (HAZID) Preliminary Summary

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8/28/2025

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1. Introduction

The Central Appalachian Basin CO_2 National Network for Enhancing Carbon Transport Infrastructure Onshore/Offshore (CO_2NNECTION) project seeks to develop the pre-Front End Engineering Design (pre-FEED) study of an intermodal transport hub. The objectives of the studied project are to design, engineer, and develop an efficient and economic network to transport CO_2, using multimodal methods, from sources to sinks, in the tristate region of Ohio, Pennsylvania, and West Virginia. In this effort, the regional infrastructure of roads, rail and river transportation methods are considered along with the construction of new infrastructure.

To supplement the pre-FEED study, a high-level hazard identification (HAZID) study was conducted to assess potential risks associated with transporting CO_2 from point-source emitters to injection wells using truck, rail, and pipeline modalities. The transportation hub under evaluation is located in the Appalachian region, where industrial activity and subsurface storage potential intersect. The goal of this HAZID was to identify credible hazards, evaluate their likelihood and consequences, and propose mitigation strategies to support safe and reliable CO_2 transport operations.

2. Methodology

The HAZID study included two parts: an accounting of the potentially sensitive areas that might be impacted by the intermodal hub, and an assessment of the likelihood and severity of potential leakage scenarios from each transport mode. Surface conditions, including High Consequence Areas (HCAs), critical infrastructure, and other sensitive areas, were identified using a process described by Battelle (2024)[1]. The process uses publicly available shapefiles to define or approximate the HCAs and sensitive areas, considers how the development of pipelines could impact these areas, discusses the prioritization of minimizing impacts, and presents possible mitigation scenarios. This approach was adapted to accommodate all applicable modes of transportation. Subject matter experts (SMEs) in chemical engineering and geologic storage were engaged through structured workshops to identify risks specific to each transport mode and interface points (e.g., loading terminals, compression stations, and injection sites).

The evaluation of the relevant modes of transport and the environmental and social impacts of the studied transportation system was completed by using publicly available peer reviewed literature and subject matter experts. The potential impacts of development will be evaluated using a qualitative risk assessment, which included the likelihood of the impact occurring (on a scale from 1-5) and its severity (also on a scale of 1-5) as shown in Table 1. A Risk Ranking was calculated by multiplying the likelihood and severity. Impacts that have a Risk Ranking of 20 or more or a Severity of 4 or 5 were evaluated using the Bowtie Risk Assessment methodology described by Alizadeh & Moshashaei (2015). This includes the evaluation of top-line events (hazards), considering the causes and consequences of the hazards, detailing control measures to prevent hazards, recovery mechanisms to recover from a hazard, and threats to the developed controls measures. The risk rating is also considered for five subcategories of impact areas, which includes: human population, water supply, buildings, infrastructure, and environment. While there are some overlapping areas between these categories, they differentiate between the potential impacts to the region should a leak occur within the transportation system. In this evaluation, buildings refers to areas populated by

[1] Battelle. 2024. Midwest Regional Carbon Initiative Infrastructure Assessment Task 4 Budget Period 2 Technical Status Report. DOE Award No.: DE-FE0031836.

humans, such as commercial or residential sites, while infrastructure refers more to the underlying systems, utilities, and transportation networks that keep the region functional.

As a final note, the risk matrix evaluates some causes for a large or small leak where appropriate. For example, there are numerous pipeline leak scenarios that could result in a small leak or a larger rupture in the event of a system failure. Rail and truck transportation is more defined with the volume of CO_2 leakage possible.

Table 1: Qualitative Likelihood and Severity Ratings to Evaluate Transportation Risks

		Severity				
		1 - Insignificant	2 - Minor	3 - Significant	4 - Major	5 - Severe
Likelihood	1 - Rare	1 - Very Low	2 - Very Low	3 - Low	4 - Medium	5 - Medium
	2 - Unlikely	2 - Very Low	4 - Medium	6 - Medium	8 – Medium	10 - High
	3 - Possible	3 - Low	6 - Medium	9 - Medium	12 - High	15 - Very High
	4 - Likely	4 - Medium	8 - Medium	12 - High	16 - Very High	20 - Extreme
	5 - Almost Certain	5 - Medium	10 - High	15 - Very High	20 - Extreme	25 - Extreme

3. Results

The risk matrix and bow-tie diagrams are included in Appendix A for review, but a summary of the information is below. The risk matrix for the multi-modal CO_2 transportation hub highlights several high-priority hazards that pose significant threats to safety, infrastructure, and environmental integrity. Among the most severe risks is vehicle collision during truck transport, which resulted in a high likelihood and potential impact on human populations and infrastructure. This risk is particularly concerning in densely populated or high-traffic areas and requires robust mitigation strategies such as driver training, route optimization, and reinforced containment systems. Another critical risk is derailment during rail transport, reflecting its potential to cause disruption and damage to buildings and infrastructure. Preventive measures like track maintenance and emergency response planning are essential to reduce this risk.

A third notable hazard is sabotage, which, while less likely, carries a high severity score due to its potential to affect all transport modes and cause cascading failures across systems. This risk underscores the need for comprehensive security protocols, surveillance, and coordination with emergency services. Additionally, weather-related pipeline rupture and flooding-induced earth movement were identified as significant risks due to their potential to compromise infrastructure and environmental safety. These findings emphasize the importance of designing resilient systems, conducting geotechnical assessments, and integrating climate adaptation strategies into project planning. Overall, the matrix provides a clear framework for prioritizing risk mitigation and assigning responsibilities across operators, engineers, and emergency planners.

HCA and Sensitive Areas Summary

HCAs and sensitive areas were addressed through a process defined by Battelle (2024) in conjunction with TRC Companies pipeline routing tool (Pivvot). Pivvot was used to develop realistic pipeline routes for Scenarios A and B, defined in the Basis of Design document (Battelle, 2025). The software is able to determine several factors about the route, including the (1) colocation of existing rights-of-way (ROWs) versus greenfield; (2) intersections with Commercial Navigable Waterways (CNW); (3) the number of affected property owners (by county); (4) United States Fish and Wildlife Service (USFWS) Critical Habitats; (5) waterbodies, wetlands, and floodplains (6) Pipeline and Hazardous Safety Administration (PHMSA) High Population Areas (HPAs) and Other Populated Areas (OPAs); (7) land cover, slope, and peak ground acceleration; and (8) structure outlines. A summary the number of the Pivvot results for each feature is presented in Table 2. Severity ratings for each feature type are altered in the qualitative risk rankings. As such, the feature types are categorized in the table.

Table 2. HCAs and sensitive areas impacted by the pipelines of Scenario A and Scenario B. features are categorized by feature type considered in the risk assessment.

Feature	Scenario A	Scenario B
Human Populations		
PHMSA HPAs (Miles)	12.1	0
PHMSA OPAs (Miles)	0.8	0.4
Water Supply		
Waterbodies Lakes (Miles)	<0.1	<0.1
Waterbodies Linear (Count of crossings)	143	159
Buildings		
Structure Outline (Count of intersections)	198	50
Infrastructure		
Existing ROWs (% of route existing ROW)	78%	73%
Pipeline (miles)	72.3	103.0
Powerline (miles)	25.6	5.0
Railroad (miles)	0	0.6
Road (miles)	4.2	7.8
Greenfield (miles)	22.6	33.8
CNWs (Count of Crossings)	1 Crossing (Ohio River)	1 Crossing (Ohio River)
Environment		
USFWS Critical Habitats (Miles)	0	1.6
Wetlands (Miles)	0.6	0.3
Other		
100-Year Floodplains (Miles)	2.8	4.5
Land cover (Miles)		
Crops	7.6	10.3
Pasture/Grasslands	25.6	16.5
Forests	60.5	103.8
Developed (Open)	5.1	4.3
Developed (Low)	1.3	1.1
Developed (Medium)	0.8	0.5
Developed (High)	0.2	<0.1
Baren	<0.1	<0.1
Open Water	0.3	0.5
Wetlands	0.5	0
Slope (Miles)		
< 5%	9.7	6.8
5 – 10%	12	8.4
10 – 15%	18.3	12.4
15 – 20%	20.6	19.9
20 – 25%	15.7	23.7
25 – 30%	9.7	21.5
30 – 35%	6.2	15.6
35 – 40%	4.2	10.4
40 – 45%	2.6	6.8
45 – 50%	1.2	4.9
> 50%	1.7	8.1
Peak ground acceleration (Miles)		
1 – 2	78.2	46.1
2 – 3	23.6	93.2

4. Conclusions and Path Forward

The HAZID information developed during the pre-FEED phase can be critical input for the FEED (Front-End Engineering Design) study, serving as a foundation for detailed engineering decisions and risk-informed design. Specifically, the identified hazards, risk scores, and mitigation strategies will guide the selection of materials, equipment specifications, and layout configurations for pipelines, terminals, and transport interfaces. For example, risks like corrosion, sabotage, and flooding will influence the choice of pipeline coatings, cathodic protection systems, and elevation or drainage design. The severity breakdown across human, environmental, and infrastructure categories will also inform safety buffer zones, emergency response planning, and community engagement strategies.

In addition, the HAZID results can be used to develop a formal risk register that integrates into the FEED documentation and project management systems. This register will help prioritize engineering controls, define monitoring and inspection protocols, and allocate responsibilities across project teams. The bow-tie diagrams and risk matrix will support regulatory submissions, permitting applications, and stakeholder communications by demonstrating proactive risk management. As the FEED progresses, the HAZID can be revisited and refined with updated design inputs, ensuring that safety and reliability remain central to the project's development. This continuity between pre-FEED and FEED phases helps reduce uncertainty, avoid costly redesigns, and build confidence among investors and regulators.

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Appendix A: Supporting Documentation

Table 3: Transportation HAZID Risk Matrix

				Severity Impact Subcategories					Risk Ranking					
Transport Mode	**Risks**	**Causes**	**Likelihood**	**Human Population**	**Water Supply**	**Buildings**	**Infrastructure**	**Environment**	**Human Population**	**Water Supply**	**Buildings**	**Infrastructure**	**Environment**	**Mitigation Strategy**
Pipeline	Internal Corrosion - leak (Small)	Moisture and impurities	3	3	1	3	2	2	9	3	9	6	6	Cathodic protection, regular inspections, material selection, purity requirements
Pipeline	Internal Corrosion - leak (Large)	Moisture and impurities	2	4	3	4	3	3	8	6	8	6	6	Cathodic protection, regular inspections, material selection, purity requirements
Pipeline	Internal Corrosion - leak (Small)	Improper Pipeline Material Selection	3	3	1	3	2	2	9	3	9	6	6	Material compatibility testing, purity requirements, apply coatings, design for extremes
Pipeline	Internal Corrosion - leak (Large)	Improper Pipeline Material Selection	1	4	3	4	3	3	4	3	4	3	3	Material compatibility testing, purity requirements, apply coatings, design for extremes
Pipeline	External Corrosion - leak (Small)	Soil and Moisture	3	3	1	3	2	2	9	3	9	6	6	Apply coatings, cathodic protection, monitor soil conditions
Pipeline	External Corrosion - leak (Large)	Soil and Moisture	2	4	3	4	3	3	8	6	8	6	6	Apply coatings, cathodic protection, monitor soil conditions
Pipeline	Pipeline over pressurization - leak (Small)	Phase Change/thermal instability	2	3	1	3	2	2	6	2	6	4	4	Develop monitoring, evaluate local environments, material selection
Pipeline	Pipeline over pressurization - leak (Large)	Phase Change/thermal instability	2	4	3	4	3	3	8	6	8	6	6	Develop monitoring, evaluate local environments, material selection
Pipeline	Third-party damage (e.g., excavation) (Small)	Excavation near pipeline (Human Error)	3	3	2	3	2	2	9	6	9	6	6	Right-of-way surveillance, public awareness campaigns, permitting coordination
Pipeline	Third-party damage (e.g., excavation) (Large)	Excavation near pipeline (Human Error)	3	4	4	4	3	3	12	12	12	9	9	Right-of-way surveillance, public awareness campaigns, permitting coordination
Pipeline	Weather Causing Pipeline Rupture	Extreme temperature fluctuations	2	4	3	4	3	3	8	6	8	6	6	Design for thermal expansion; insulation; monitoring systems
Pipeline	Weather Causing Pipeline Rupture	Ground movement due to freeze/thaw cycles	2	4	3	4	3	3	8	6	8	6	6	Geotechnical surveys; flexible joints; route planning
Pipeline	Running Ductal Fracture	Water impurities	2	4	3	4	3	3	8	6	8	6	6	Use fracture arrestors, monitor pressure surges, conduct regular integrity assessments
Rail	Derailment with CO_2 release	Poorly maintained tracks/trains	2	3	1	3	4	2	6	2	6	8	4	Track maintenance, automated braking systems, emergency response planning
Rail	Derailment with CO_2 release	Operator error or excessive speed	3	3	1	3	4	2	9	3	9	12	6	Training programs; speed control systems
Rail	Valve failure during transfer	Mechanical wear or improper operation	3	4	1	4	2	2	12	3	12	6	6	Routine valve inspections, automated shutoff systems
Rail	Rail car stress fracture	Low temperature embrittlement	2	3	1	3	2	2	6	2	6	4	4	Appropriate material selection, routine inspections
Rail	Corrosion leading to leak	Moisture and impurities	2	3	1	3	2	3	6	2	6	4	6	Routine analysis of CO2, impurity thresholds defined
Truck/Rail	Weather Causing Equipment Failure	Freezing temperatures affecting valves and seals	2	3	1	3	2	2	6	2	6	4	4	Use weather-resistant components; heating systems
Truck/Rail	Weather Causing Equipment Failure	Flooding damaging electrical systems	3	3	1	3	2	2	9	3	9	6	6	Elevated equipment; waterproof enclosures
Truck	Vehicle collision with CO_2 release	Driver Fatigue/Poor Road Conditions	3	4	1	4	3	2	12	3	12	9	6	Driver training, route planning, double-walled containment
Truck	Exposure during loading/unloading	Improper handling or equipment failure	3	4	1	4	2	2	12	3	12	6	6	Safety protocols, PPE, automated loading systems
Truck	Truck trailer stress fracture	Material Embrittlement	2	3	1	3	2	2	6	2	6	4	4	Develop thermal cycle protocols, use ASME approved materials, routine inspections

Transport Mode	Risks	Causes	Likelihood	Human Population	Water Supply	Buildings	Infrastructure	Environment	Human Population	Water Supply	Buildings	Infrastructure	Environment	Mitigation Strategy
Truck	Corrosion leading to leak	Moisture and impurities	2	3	1	3	2	3	6	2	6	4	6	Routine analysis of CO2, impurity thresholds defined
Truck	Truck trailer stress fracture	Over pressurization due to Thermal Instability	2	3	1	3	2	2	6	2	6	4	4	Use DOT MC-338 cryogenic Tank Trailers with PRVs, routine inspections, real-time monitoring systems
All	Sabotage - leak (Small)	Intentional damage by external actors	3	3	2	3	2	2	9	6	9	6	6	Implement security protocols, surveillance, and emergency response plans
All	Sabotage - leak (Large)	Intentional damage by external actors	2	4	2	4	2	2	8	4	8	4	4	Implement security protocols, surveillance, and emergency response plans
All	Flooding Leading to Failure of Surface Equipment	Heavy rainfall overwhelming drainage	3	3	4	3	2	2	9	12	9	6	6	Elevate infrastructure, improve drainage, flood risk mapping
All	Flooding Leading to Earth Movement	Soil saturation causing landslides	3	4	2	4	2	2	12	6	12	6	6	Geotechnical surveys, slope stabilization, route planning
All	General Equipment Failure	Aging infrastructure or lack of maintenance	3	3	2	3	2	2	9	6	9	6	6	Routine maintenance, equipment testing, operator training

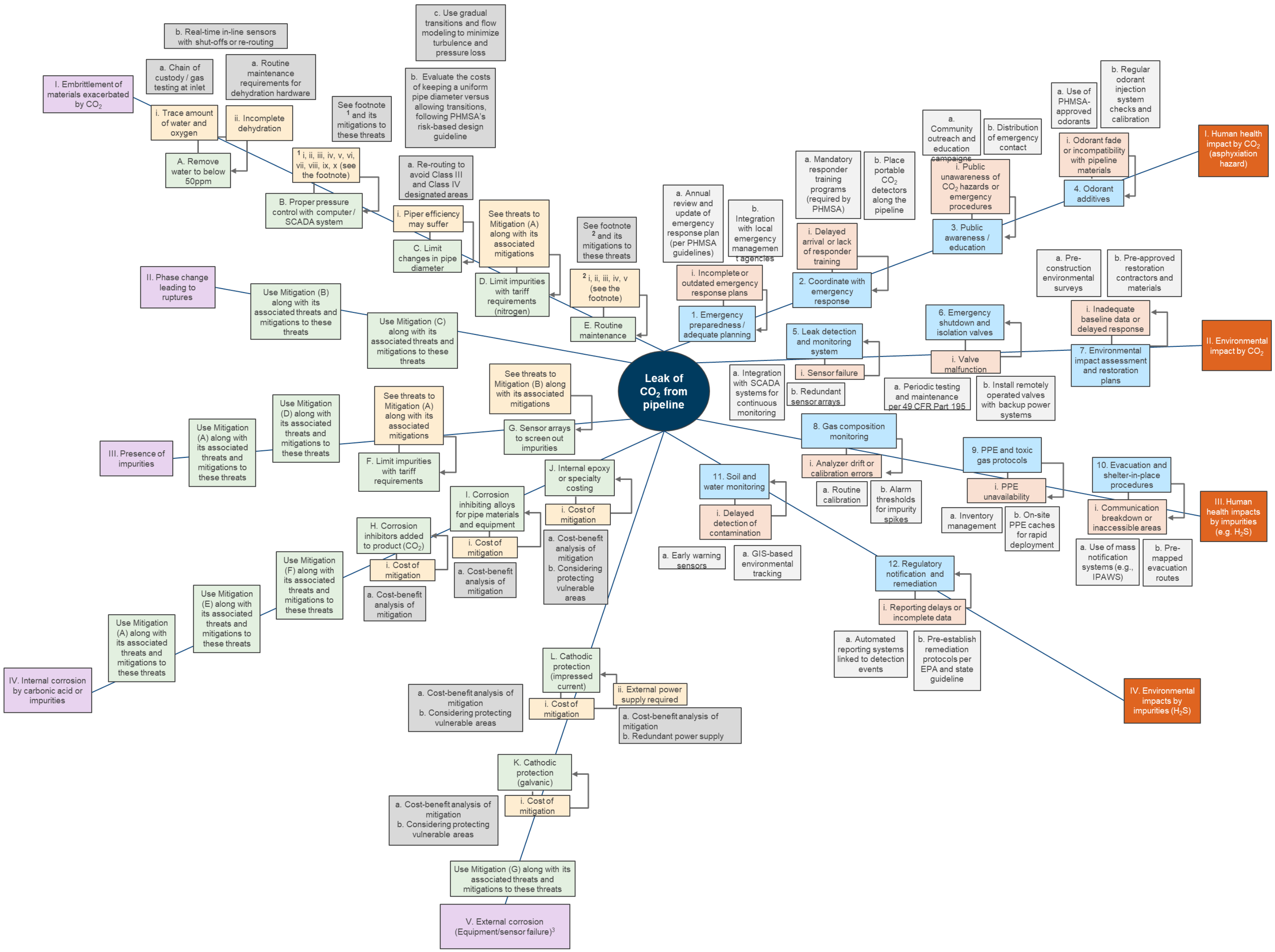

Figure 1: Pipeline Bow-Tie Diagram

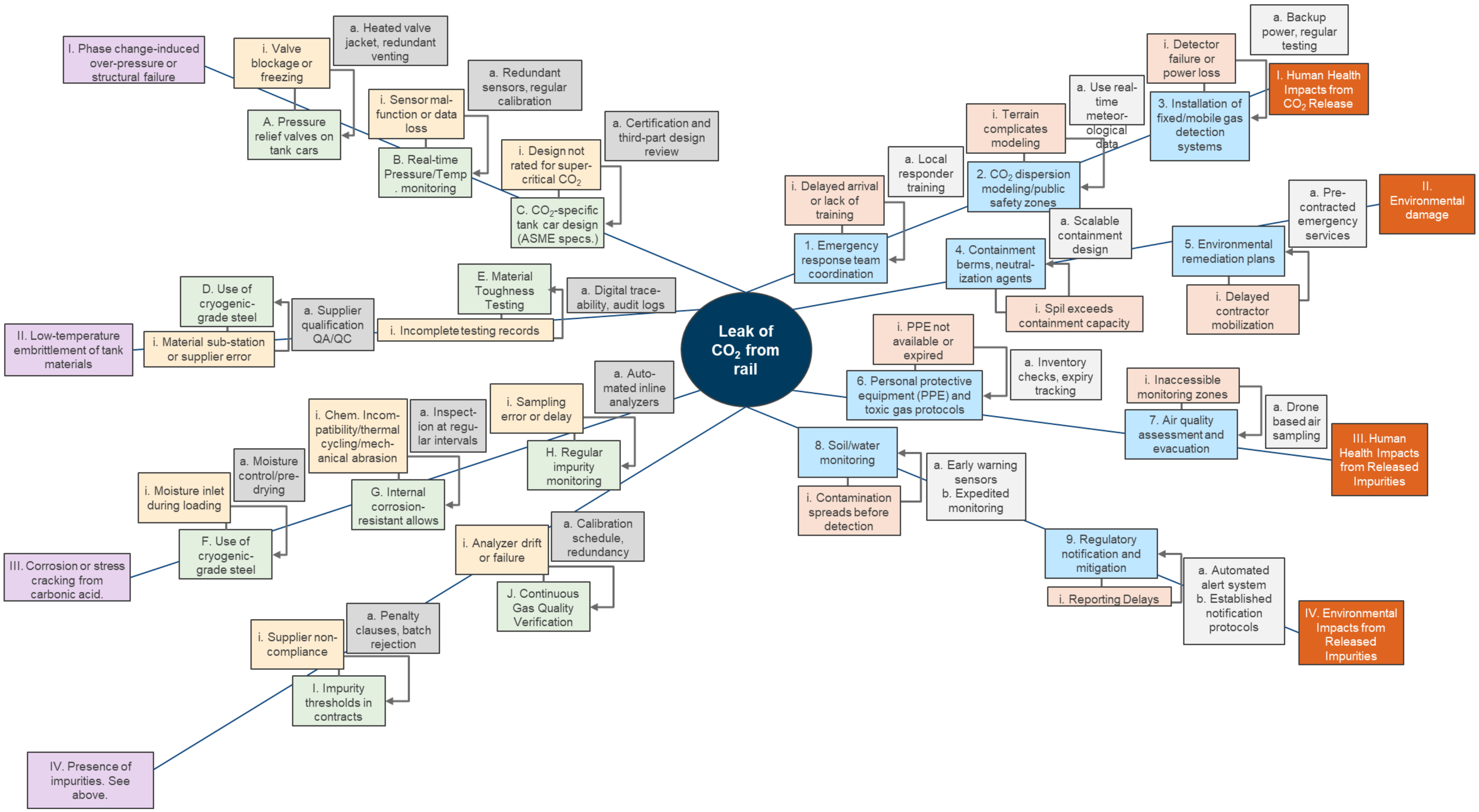

Figure 2: Rail Car Bow-Tie Diagram

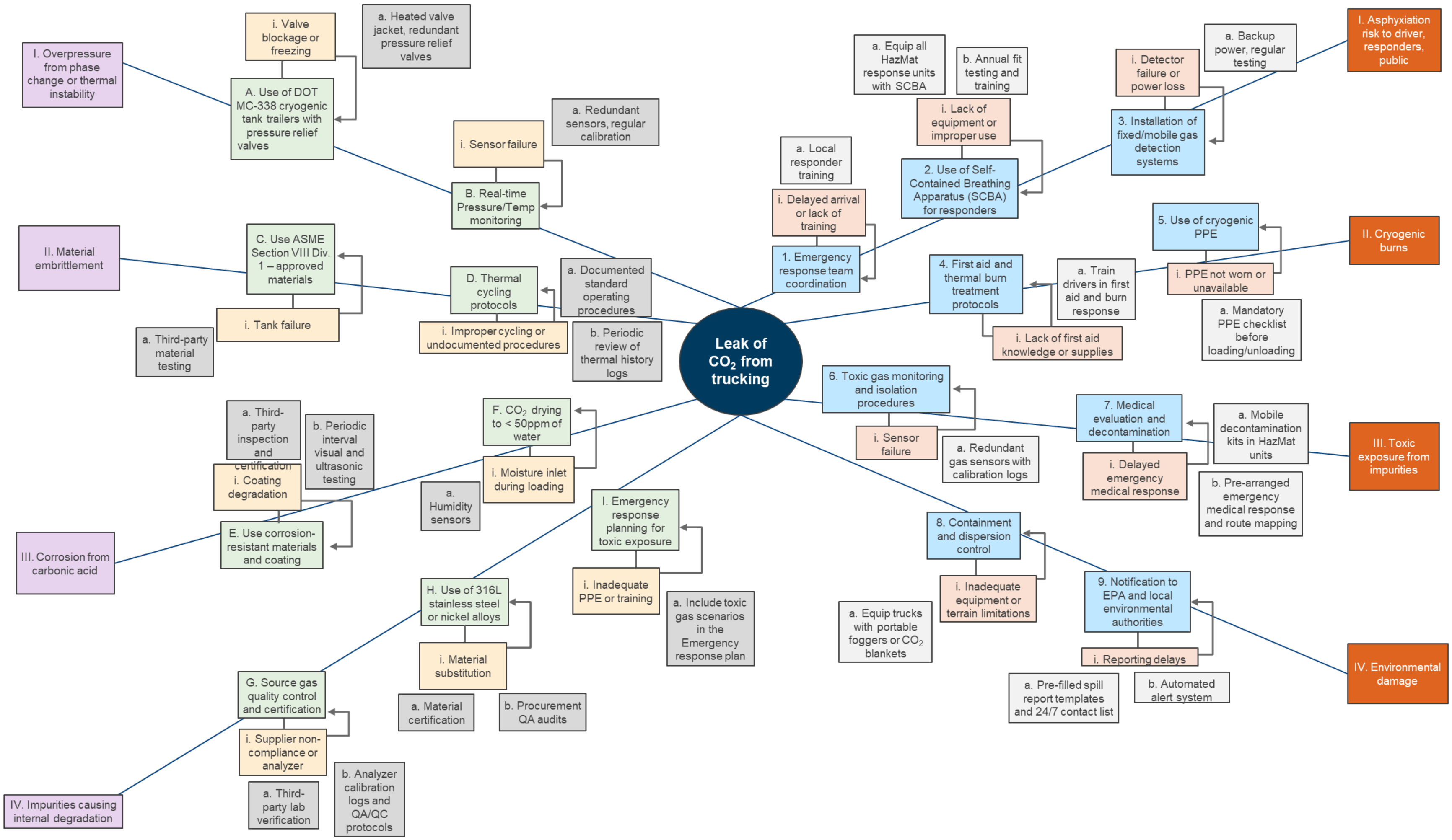

Figure 3: Trucking Bow-Tie Diagram