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Issues Related to Carbon Dioxide Pipeline Transportation Infrastructure in Louisiana

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ISSUES RELATED TO CARBON DIOXIDE PIPELINE TRANSPORTATION INFRASTRUCTURE IN LOUISIANA

A Thesis

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ABSTRACT

There is no single solution to mitigate anthropogenic climate change; a multifaceted approach with economic incentives is needed. Carbon dioxide (CO_2) enhanced oil recovery (EOR) is one such solution which provides an economic incentive, in the capture and sale of oil, for sequestering CO_2 underground. While carbon capture and subsequent geological injection are both mature technologies, there has been little discussion or appreciation for the role of pipelines. The current CO_2 pipeline infrastructure will need to significantly expand in order to accommodate increasing EOR production. However, pipeline construction costs, and institutional factors impacting development, may be key obstacles slowing the large scale implementation of CO_2-EOR. Numerous authors suggest reusing underutilized or abandoned natural gas pipelines as a way to save on CO_2 transportation costs. While there have been a few successful case studies in this regard, no work has attempted to determine the feasibility of implementing large scale pipeline conversion projects. In order to repurpose pipelines, operators will need to consider source and sink locations, pipeline capacity necessary to support an EOR project, existing pipe material and composition and pipeline utilization. This study is the first of its kind to answer these questions by using a Geographic Information System (GIS), developing proxies for pipeline design specifications, utilizing federal pipeline design reports and parish natural gas production data. The conclusions suggest that current Louisiana natural gas infrastructure is rated below the commonly suggested pressures needed to transport CO_2 in its supercritical (liquid) phase and if conversion projects are pursued, they will need to transport CO_2 in gaseous form. The methods used here have a considerable local context and may be acceptable only in states where an extensive natural gas infrastructure is in place. This research suggests there are some unique

pipeline repurposing opportunities, but those opportunities are likely lower than the optimistic suggestions of the noted literature.

CHAPTER 1: INTRODUCTION

1.1 Climate Change, Causes, and Solutions

Anthropogenic carbon dioxide (CO_2) emission rates almost doubled between 1970 and 2010 (IPCC, 2014). Emissions have caused the atmospheric CO_2 concentration above Mauna Loa, HI to rise above 400 ppm for the first time in nearly 3 million years (NOAA, 2016a). The role of CO_2 in creating a hospitable climate has been known since John Tyndall's discovery of the "Greenhouse Effect" in the 1800s, but a tipping point has been reached directly relating increased emissions with negative impacts (IPCC, 2014). Increased emissions have been linked to rising global temperatures, rising sea level, melting glaciers and the contrast between naturally dry and wet environments becoming more apparent (IPCC, 2014). Climatic changes may lead to increased natural disasters, disease outbreaks, food and water shortages and ultimately losses of human life (IPCC, 2014). The monetary costs associated with climate change can be seen in the increase in the number of billion dollar natural disasters (NOAA, 2016b). In order to avoid or mitigate climate change, a reduction of CO_2 emissions is crucial.

Carbon emissions, which were mostly flat during the course of human history, began to rise precipitously during the Industrial Revolution when humans learned to harness the energy stored in fossil fuels. The burning of fossil fuels has been directly related to the increase of atmospheric CO_2 concentrations (IPCC, 2014); so a logical solution would be to find energy sources that do not result in CO_2 emissions. Energy sources touted as replacements for fossil fuels, such as renewable energy sources, include solar photovoltaics, wind turbines and biofuels (Chu and Majumdar, 2012). Renewable energy sources have seen significant increases in capacity and generation during the last decade Figure 1 (US EIA, 2017). However, when viewed in relation

to the total U.S. energy budget, renewable energy sources represent less than 10 percent of energy capacity while fossil fuels still supply 73 percent of our overall energy demand (US EIA, 2017). Renewable energy sources also have various drawbacks that are difficult to overcome particularly in their geographic capabilities. The extensive use of energy crops (biofuels) spurs debates about using food as fuel when there are still large concentrations of malnourished populations around the world (Pimentel and Burgess, 2014). Likewise, the technical ability to generate energy from solar energy is good in an arid environment like Arizona, however, does poorly in places like Seattle (US EIA, 2011). Wind turbines have excellent technical capabilities in the windswept Midwest, but perform poorly in the Southeast (US EIA, 2011). While many of these geographic challenges can be solved, in part, with large transmission systems, they cannot overcome weather. The sun does not always shine and the wind does not always blow causing considerable generation availability challenges (Ellabban et al., 2014). There is also a scale issue since many renewable resources are provided at a kW-level of scale rather than MW-level needed to displace large coal baseload facilities. Thus, based on the sheer volume of consistent energy needed, it is obvious the combustion of fossil fuels will continue to play a significant role in the U.S. energy budget for the foreseeable future.

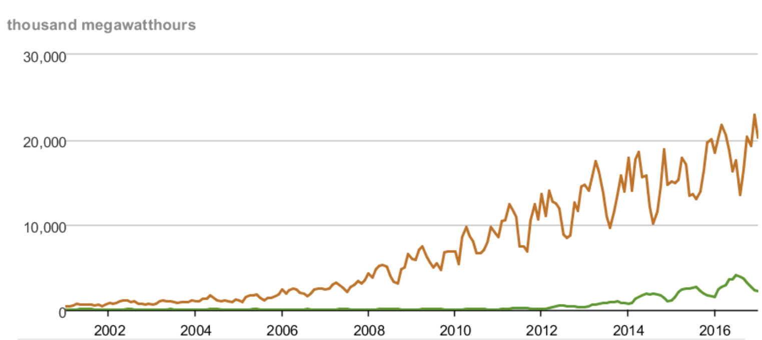


Figure 1. Increases in generation of wind (orange) and solar (green) energy. Image obtained from US EIA (2017).

1.2 Carbon Capture and Storage and Enhanced Oil Recovery

Carbon capture and storage (CCS) is also a viable means to mitigate harmful CO_2 impacts. While renewable energy sources stop the production of CO_2, CCS captures emissions and sequesters the greenhouse gas underground in saline reservoirs or depleted oil fields (Figure 2) (Benson and Surles, 2006). CCS allows the U.S. to continue to rely on efficient fossil fuels without the negative climatic drawbacks. The main obstacle faced by CCS is economic feasibility. The International Energy Agency (IEA) estimates CCS costs between \$50-90/tonne (t) CO_2 sequestered (Simbolotti, 2010). Capturing CO_2 from fossil fuel combustion accounts for 50-75 percent of the total cost of CCS due to reduced efficiencies in energy production. Increases in the cost of energy production will ultimately be handed down to consumers in the form of larger energy bills (Metz et al., 2005; Davidson et al., 2001; Gaspar et al., 2005; Finkenrath, 2011). Without economic incentives, largely through various forms of cost subsidies, CCS is seen as an unpopular mitigation measure by both the industry and consumers.

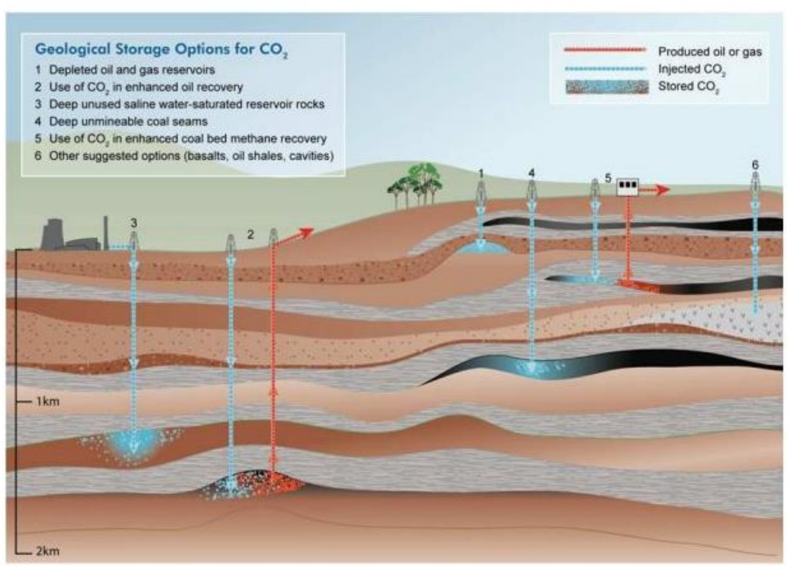


Figure 2. Carbon storage in geologic reservoirs. Taken from Dooley et al. (2006).

One method that can increase the attractiveness of a CCS process is through use of enhanced oil recovery (EOR). While traditional CCS stores carbon in saline reservoirs or depleted oil fields, EOR injects CO_2 into oil fields in order to increase production typically from older legacy fields. CO_2-EOR is not a novel idea; the process dates back to the early 1970s when CO_2 injection was used to recover the vast amount of stranded oil left behind after primary and secondary recovery (Sandrea and Sandrea, 2007). The first pilot EOR tests were conducted in the Mead-Strawn and Scurry Area Canyon Reef Operators Committee (SACROC) units of west Texas (Holm and O'Brien, 1971; Dicharry et al., 1973). Companies found CO_2-based EOR was able to recover 50 percent more oil than water flooding alone, producing 4-12 percent of the original oil in place (Gozalpour et al., 2005). The economic feasibility of CO_2-EOR projects is a function of the cost of purchasing CO_2, drilling wells to inject the CO_2 and the selling price of oil (Norman, 1994; NETL, 2010). When CO_2 prices are low and oil prices are high, industry has the incentive to utilize this technique.

Since the early pilot tests, CO_2-EOR has become widespread with more than 136 operations in traditional producing basins in Texas, Wyoming, Oklahoma, Mississippi and Louisiana (Kuuskraa and Wallace, 2014). Over time the oil and gas industry has been able to expand due to the use of inexpensive, naturally-occurring CO_2 sources from underground formations like the Jackson Dome in Mississippi. Of the 8.7 million barrels of oil per day produced in 2014, CO_2-EOR contributed 300,000 barrels per day, or approximately 3 percent of production, while sequestering 3.5 MMcf/day of CO_2 (Kuuskraa and Wallace, 2014). Projections for 2020 predict CO_2-EOR production should double and while the majority of projects are currently located in west Texas, the Gulf Coast (including areas outside of Texas) may see significant

production opportunities (Kuuskraa and Wallace, 2014). The U.S. government is committed to developing economical solutions to help mitigate climate change demonstrated by the distribution of $14 million to research universities to help EOR expand and become more efficient (US DOE, 2014).

1.3 Louisiana EOR

Louisiana is uniquely poised to take advantage of CO_2-EOR due to an extensive history of fossil fuel production, extensive underground sink storage opportunities, and a large industrial sector (source). Louisiana ranked eighth in overall energy production in 2014, fifth in natural gas and 9th in crude oil (US EIA, 2017). Since the first well was drilled near Jennings, LA in 1901, the Louisiana Department of Natural Resources (LDNR) has kept a record of the approximately 1,800 oil and gas fields spread throughout the state (SONRIS, 2017). These fields are very mature with most seeing little or limited crude oil production and would be ideal candidates for CCS or EOR.

In addition, Louisiana's large industrial sector contributes 60 percent of the state's overall CO_2 emissions compared to the average U.S. state's industrial sector which only contributes 18 percent, Figure 3 (US EIA, 2017). South Louisiana's 58 reporting industrial facilities involved in

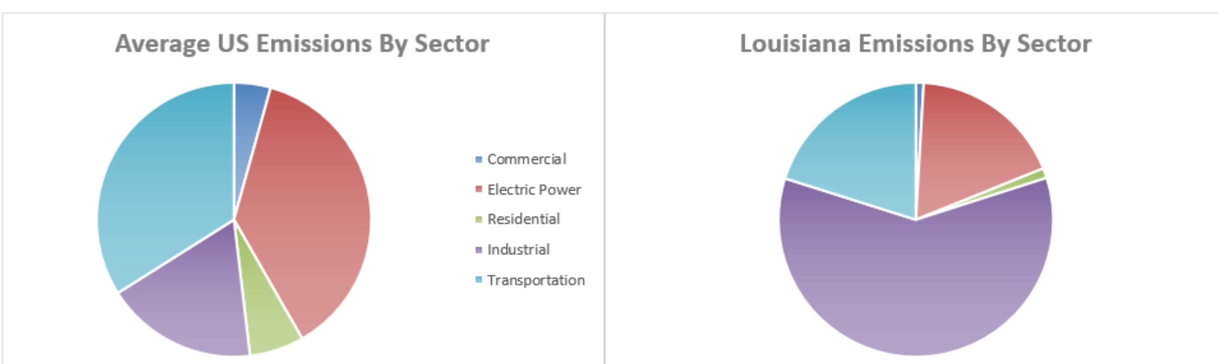


Figure 3. CO_2 emissions by sector for: 1) average state and 2) Louisiana. Data obtained from US EIA (2017) and reported for 2014.

fossil fuel refining or chemical production combined to contribute 25 MMt CO_2 to the atmosphere in 2015, Figure 4 (US EPA, 2017). Energy production, refining and chemical industries have made Louisiana fifth overall in CO_2 emissions per capita at 47 Mt per individual (US EIA, 2017). The combination of oil and gas fields, as well as large sources of relatively pure CO_2, make Louisiana a potential candidate for CO_2-EOR projects (Dismukes et al., 2017).

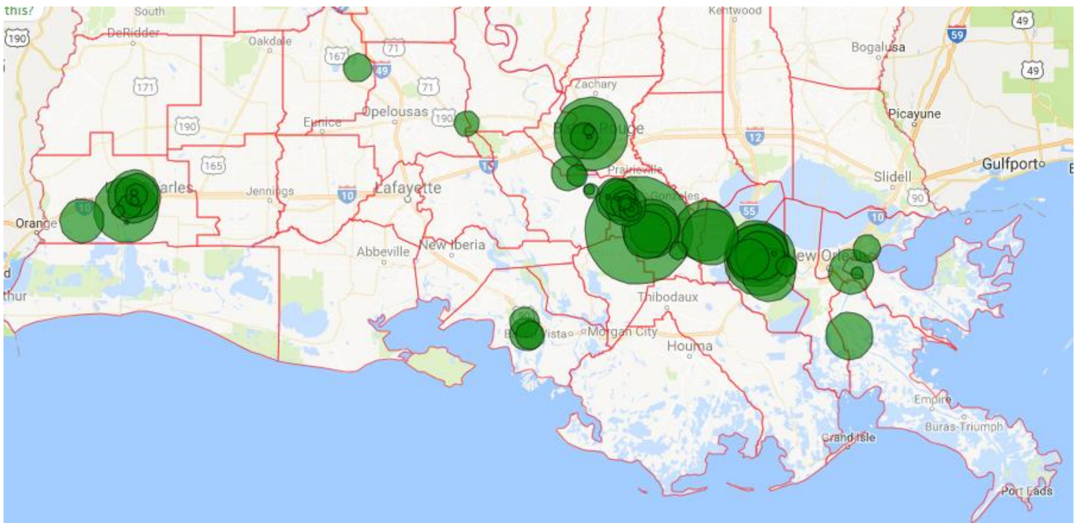


Figure 4. Location of major industrial facilities emitting CO_2 in southern Louisiana. Data obtained from US EPA (2017).

1.4 Research Proposal

While much research has focused on efficient CO_2 capture (Leung et al., 2014) and subsequent EOR (Alvarado and Manrique, 2010; Holm and O'Brien, 1971), little attention has been paid to midstream transportation. Pipelines have consistently been shown to be one of, if not the best, transportation mode in terms of efficiency, cost and safety (Svensson et al., 2004; Strogen et al., 2016). In 2015 the Pipeline and Hazardous Materials Safety Administration (PHMSA) reported over 5,200 miles of CO_2 pipeline in the U.S., but if CO_2-EOR is to continue to expand then so will its infrastructure. The National Energy Technology Laboratory (NETL)

estimates midstream companies will need to build 1,000 miles of CO_2 pipeline every year until 2030 in order to keep up with the pace of potential EOR opportunities (Wallace et al., 2015). The U.S. has a vast network of natural gas pipelines in place, but little experience building and maintaining CO_2 pipelines. CO_2 has a number of physical and technical differences from natural gas making pipeline design specifications important in understanding differences in costs and permitting procedures. The objective of the present study is to highlight the current existing CO_2 infrastructure in Louisiana, the costs of building pipelines, the nuances of converting natural gas pipelines to CO_2, and then develop a methodology to determine the feasibility of implementing large scale conversion projects in Louisiana.

CHAPTER 2: LITERATURE REVIEW

2.1 Technical Aspects of Natural Gas Pipelines

Large scale natural gas production and usage is primarily facilitated by pipeline-based transportation. Other forms of transportation are typically found to be either too inefficient or too expensive and are often used as niche forms of transportation. Natural gas can be transported via pipelines efficiently and safely (Svensson et al., 2004; Strogen et al., 2016). The first oil and natural gas pipelines were developed in the late 1800s and have since expanded to 200,000 and 2,200,000 miles, respectively (PHMSA, 2017). The modern pipeline industry has expanded further to include such industrial gases as nitrogen, helium ammonia, hydrogen, CO_2 and various refined products and commodity chemicals.

Natural gas pipelines can be separated into three different types based on their operating conditions and use, Figure 5, (Folga, 2007). Gathering lines are generally small diameter (2-6 inches (in)), low pressure lines which move raw natural gas from the producing field and transport it to a processing plant where impurities are removed and the product is refined. After processing, natural gas is then transported via large diameter (6-48 in), high pressure (500-1,400 psi) transmission lines which cover long distances either intra or interstate. Finally, natural gas is "stepped down" via various types of regulators to be distributed via smaller diameter (2-24 in), lower pressure distribution lines either directly to industrial consumers or through a citygate: a local company which owns its own distribution infrastructure.

Pipelines are made of various materials and protective coatings. Historically, pipelines were developed using wrought iron and cast iron which continue to be phased out and are being replaced by more durable carbon steel pipe (PHMSA, 2017) as well as plastics. Carbon steel

pipelines can transport high pressure natural gas but are expensive and used mostly for transmission. Plastic pipelines, primarily used in distribution, are cheaper and more flexible but are not acceptable for high pressure (>100 psi) situations. Specialized coatings are applied after manufacture, specifically to carbon steel, in order to protect against corrosion and rust which can include an epoxy or polyethylene coating and/or cathodic protection (Folga, 2007). In addition, considerations are needed for welding material, number of compressor stations, and the Supervisory Control and Data Acquisition (SCADA) systems used to manage the product and respond to emergencies.

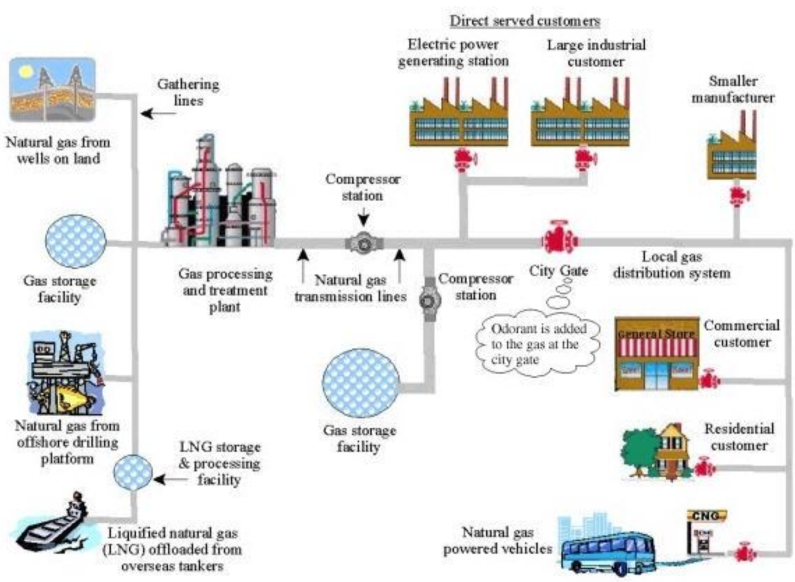


Figure 5. Parts of the pipeline industry from upstream to downstream. Image taken from PHMSA (2017).

The volume of natural gas a pipeline can carry is determined by its Maximum Allowable Operating Pressure (MAOP), which is a function of the pipe design specifications and the terrain. MAOP can be calculated using Equation (1):

$$MAOP = (2*T*S*0.72)/D \quad (1)$$

where S=Specified Minimum Yield Strength (SMYS), T=wall thickness, D=outside diameter and 0.72 is a variable design factor (49 CFR 192.111, 192.5). The SMYS is the minimum pressure the pipe can withstand before becoming deformed and is determined by the grade of steel. The design factor is used to lower the odds of a pipeline incident by providing room for unexpected pressure fluctuations. Most rural pipelines use a design factor of 0.72, however, pipelines within close proximity to highly populated areas (called high consequence areas (HCA)) will have a lower value which can range from 0.72-0.4. Due to the safety factor, natural gas pipelines are rated significantly below their manufactured rating to ensure public safety.

Construction of pipelines is a lengthy, and often contentious, process. Well in advance of construction, companies must apply for permits through various organizations (see Section 2.5) and obtain proper Right of Ways (ROW). Right of Ways are permits from private and public land owners who consent to having a pipeline on their property. Most pipelines are located at least 30 inches below the surface and require clearing and trenching of the land before pipes are strung together. Land disturbance during construction is a significant issue; ROW width can call for clearing land up to 50 feet on either side of the pipeline (Sepra et al., 2011). Pipes are strung along the trench, welded together and if applicable, bent to conform to the terrain. Once the pipeline is complete, testing is conducted in order to ensure of no leaks via hydrostatic testing and/or in-line pigging. Lastly, the area is backfilled and restored. Pipeline development can take years of planning and require millions, if not billions, of dollars of investment before natural gas can be transported.

Costs are broadly separated into capital expenditures (CAPEX) and operational expenditures (OPEX). CAPEX are the upfront expenses to build the pipeline and are further

divided into four categories: construction labor, miscellaneous, ROW, and materials. Construction labor, being the most expensive component of natural gas pipelines, consists of 47 percent of the total budget followed by miscellaneous (34 percent), materials (13 percent), and ROW (6 percent) (Smith, 2016). Miscellaneous consists of the costs associated with surveying, engineering design, administration, filing fees and interest. Historically, construction labor and materials have shared similar costs but during the last decade the cost of materials has dropped dramatically, even falling behind miscellaneous, while construction labor continues to remain high (Smith, 2016). OPEX are expenses incurred during normal use which include regular maintenance, repair and fuel to power compressors.

Developing a pipeline is a monumental task, as can be seen by the technical aspects of a given project. Development considerations include deciding where to produce, where to process, who will buy, volumes needed to be transported, pipeline materials, obtaining ROW and proper permits, and construction. Although constructing a pipeline is a significant time and financial investment, pipelines span the country and new pipeline projects are announced every year.

2.2 Differences in CO_2 and Natural Gas Pipelines

While natural gas and CO_2 are both gases at standard temperature and pressure, there are subtle differences in how they are transported in pipelines. The physical phase of any specific molecule changes with respect to temperature and pressure. For example, if pressure is held constant while temperature is increased, the molecule will transform from a solid to a liquid and to a gas. Supercritical fluid is often the most economical means of transporting CO_2 because of its high density and low viscosity; supercritical fluid has the density of a liquid but the flow of a gas (Zhang et al., 2006). The point at which a molecule is at its supercritical phase is termed the

critical point. Methane and CO_2 differ with respect to their critical point; -82.3°C/ 673 psi and 30.9°C/1070 psi, respectively (Figure 6).

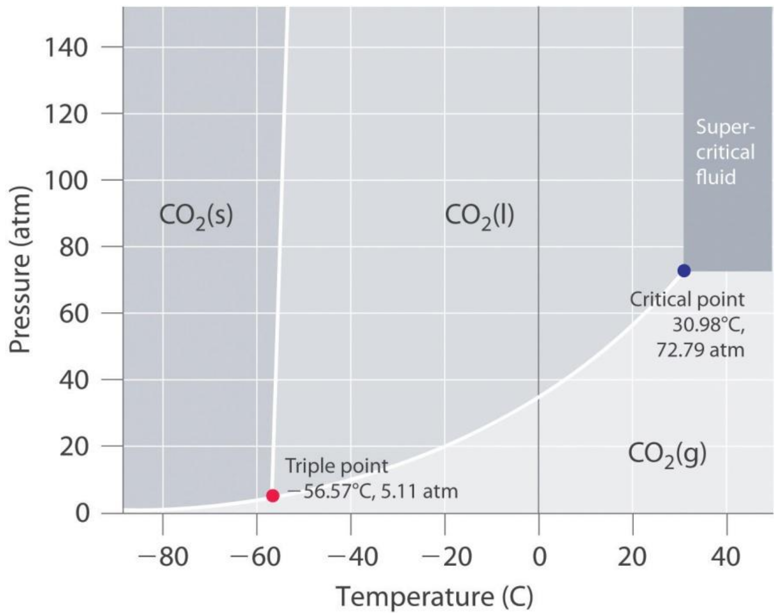


Figure 6. Phase diagram of CO_2 with respect to temperature and pressure. Image taken from: Averill and Eldredge (2012).

Natural gas is generally transported on pipelines in gaseous form and at pressures between 800-1,160 psi (Serpa et al., 2011), whereas supercritical CO_2 (liquid) needs to be transported at a minimum of 1,070 psi. Pressures for CO_2 transportation will likely need to be much higher, at least 1,200 psi, in order to avoid phase changes associated with temperature fluctuations (40-100°F) (MRCSP, 2005; WRI, 2008). If the pressure drops low enough, CO_2 will change phase and frictional loss within the pipeline can hinder transportation (IPCC, 2005). Currently, all major CO_2 pipelines transport at pressures above 1,900 psi (Sepra et al., 2011). CO_2 can be transported at lower pressures in its gaseous phase, but the economies of doing so are less attractive. Also, EOR applications require supercritical CO_2 and so, if not compressed at the

time of capture for transportation, the gas will need to be compressed at the injection site (Zhang et al., 2006). CO_2 has a high critical point that requires additional pipeline design considerations.

2.3 CO_2 Material Considerations

CO_2 and natural gas pipelines are generally built in much the same way with the exception being that CO_2 pipelines generally require higher quality materials. ASME B31.8 describes the design specifications of pipe material. Steel grade is classified by the American Petroleum Institute (API) as “X” followed by a number; the number designates the SMYS. The higher pressures needed for supercritical CO_2 require pipeline yield strength between 60,000-80,000 psi which designates the use of API X60-X80 (WRI, 2008). Cost models show using higher grades of steel, X80 and above, create lower cost scenarios for supercritical flow (Knoope et al., 2014). As an example of design specifications, the Canyon Reef pipeline feeding the SACROC unit consists of pipelines whose MAOP is 2,194 psi for a 16 in, 0.375 in wall, X65 pipe and 2,526 psi for a 12.75 in, 0.344 in wall X65 pipe assuming the design factor is Class 1 (Metz et al., 2005).

Supercritical CO_2 can create component problems for pipelines. Polymers and lubricants can absorb supercritical CO_2, causing components to swell, and once pressure is released, o-rings and seals can crack or rupture. Boot-Handford et al. (2014) recommends Teflon and Viton polymers as more durable components. Higher-rated flanges, connecting two pipes together, are required in order to withstand the additional pressure (Antaki, 2003). CO_2 will need additional and expensive compression if traveling over long enough distances or traversing challenging terrain. Unlike natural gas pipelines which use gas compressors, CO_2 pipes require booster stations equipped with fluid pumps in order to handle the fluid like phase (van der Zwaan et al., 2011; WRI, 2008). Recompression is the single largest component of operating costs (WRI, 2008)

but can be kept to a minimum with shorter transportation distances requiring fewer compressor stations or larger diameter pipelines which reduce pressure drop (Leung et al., 2014). Whether transporting in the supercritical or gaseous phase, Tang et al. (2017) found that there are no differences in pipeline corrosion issues, thus, deciding which phase to use will be based on project requirements and economics. While CO_2 pipelines require the use of higher quality, more expensive components, WRI (2008) found material considerations are not an obstacle that will hinder the industry.

2.4 Impurities

CO_2 is never 100 percent pure and contains impurities that can affect pipeline integrity. Impurities include water (H_2O), hydrogen sulfide (H_2S) and nitrous oxides (NO_x). All of these impurities can lead to corrosion but the most important is H_2O. Dry CO_2 does not pose a problem in terms of corrosion. The IPCC (2005) found corrosion rates of 0.01mm/yr on surveyed CO_2 pipelines. However, wet CO_2 can form carbonic acid (H_2CO_3) which will quickly corrode pipelines. In addition, the presence of H_2O and H_2S can create sulfuric acid (H_2SO_4) leading to excessive corrosion. Ultimately, the CO_2 stream can contain impurities but as long as it is dry there should be no corrosion problem. Beyond corrosion, Bilio et al. (2009) found the equations of state used to determine the phase of CO_2 do not consider impurities which will alter the temperatures and pressures needed to keep CO_2 in supercritical phase. However, different sources of CO_2 contain varying amounts of impurities which makes developing equations of state difficult. Natural sources of CO_2 are often high purity, > 95 percent, while industrial sources are found to have varying amounts of impurities which differ by source. Impurities can be compared from sources Mahgerefteh et al. (2012), Oosterkamp and Ramsen (2008), Herron and Myles (2013).

There are currently no universally accepted or government-defined standards dictating CO_2 quality; purity specifications are often contracted between supplier and the pipeline operator. The current industry best practice is to supply CO_2 with concentrations in excess of 95 percent (Herron and Myles, 2013). However, transportation with impurities can still be done. Schremp and Roberson (1973) note pipelines in the SACROC area show no signs of pitting when transporting CO_2 with concentrations of H_2O and H_2S 20 and 2 times, respectively, what is normally seen in typical CO_2 streams. Gill (1982) confirms the SACROC pipelines are still operational after 10 years and show minimal corrosion. The Weyburn pipeline crossing the Canadian border has been transporting CO_2 with high concentrations of H_2S for 30 years without any serious problems (Onyebuchi et al., 2017). In the case where water may build up, alloy steel can be used but is more expensive and should not be used unless necessary (Boot-Hanford et al., 2014). Mechleri et al. (2017) notes excessive impurities will necessitate the need for more durable materials which ultimately increase overall costs.

2.5 Pipeline Regulation

Government oversight has historically been an important part of the natural gas industry due to the natural monopolistic tendencies of the industry and its public safety aspects. Regulation started at the municipal level where natural gas was both produced and consumed but as pipelines grew from town to town and from state to state, higher levels of government were needed. Originally, pipeline operators owned the transported product and sold to the consumer on a “bundled basis.” Over time, regulation restricted pipelines’ ability to make bundled sales forcing them to become pure common carrier transport companies (Michaels, 1993). Common carriers provide equal access to all parties on an uniform, nondiscriminatory

basis (or fee). These common-carrier pipelines are regulated at the state and federal level. Regulated common-carrier pipelines range in size from small, intrastate companies to large, interstate companies spanning most of the country.

Interstate pipelines are economically regulated at the federal level by the Federal Energy Regulatory Commission (FERC) and regulated for safety by the PHMSA. The FERC has the authority to regulate the interstate commerce of wholesale natural gas which includes overseeing and permitting new pipelines in order to promote reliable and affordable energy for consumers. The PHMSA, created in 2004, is charged with ensuring safe operation of the U.S.' pipeline system by setting safety standards and housing pipeline inventory and leak data. Chapter 49 of the Code of Federal Regulations (CFR) Part 192 defines natural gas safety standards. CO_2 pipelines, however, are regulated differently since CO_2 is classified as a hazardous liquid. In fact, the CFR has a separate section for CO_2 pipelines, (Part 195). As such, the FERC has no oversight over CO_2 pipelines stating that this responsibility falls upon the Department of Transportation's Surface Transportation Board (STB) (Nordhaus and Pitlick, 2009). The STB, however, generally regulates commodity transport other than water, oil, and gas, and currently considers interstate CO_2 pipelines as common carriers (Parfomack and Folger, 2008). However, unlike the FERC, the STB does not have active regulatory responsibilities and only acts if a dispute over pricing is brought to their attention (WRI, 2008). So far, no disputes have been filed and therefore the STB has yet to make a decision regarding any CO_2 pipeline case. Thus, outside PHMSA, CO_2 pipeline regulation is largely left up to individual states (Nordhaus and Pitlick, 2009; Mack and Endemann, 2010).

Intrastate CO_2 pipelines in Louisiana are governed by the Department of Natural Resources and are overseen by the Commissioner of Conservation. Louisiana Administrative Code Title 43: Part XI Subpart 4 outlines CO_2 pipeline design specifications which mimic 49 CFR 195; however, the regulations are only applicable to transmission lines and specifically exclude gathering lines. Companies wishing to build a CO_2 pipeline must file a Certificate of Public Necessity and Convenience (CPN) with the commissioner; however, approval of the EOR project must be granted before construction of the pipeline can begin (Songy, 2009). The commissioner's approval is also required for CO_2 pipelines that pass through the state and are used for out-of-state EOR projects (Songy, 2009). CO_2 pipelines also have eminent domain in Louisiana but can only exercise that right if they have an approved CPN certificate (Mack and Endemann, 2010). One way to avoid using eminent domain, and ROW acquisition, is to re-purpose existing pipes. Although states are largely in charge of permitting CO_2 pipelines, as the industry expands, more legal issues will arise and will spur debates about whether the current regulations are adequate or if more are needed and will be particularly true for CO_2 pipelines that cross state boundaries (Parfomack and Folger, 2008; Nordhaus and Pitlick, 2009; Mack and Endemann, 2010).

2.6 Environmental Safety Issues

CO_2 pipeline ruptures are important safety threats. Highly pressurized CO_2 lines are susceptible to longitudinal propagating fractures (Cosham and Eiber, 2008) which can result in the quick release of large CO_2 volumes (Figure 7). In addition, impurities can lead to additional pipe stress by increasing the toughness needed to arrest the fracture (Cosham and Eiber, 2008; Mahgerefteh et al., 2012). Propagating fractures can be minimized by using longitudinal crack arrestors typically placed every 500 meters (IPCC, 2005; Leung et al., 2014). Arrestors are not

meant to stop a fracture from happening, rather they minimize how long the fracture becomes. Accidents and CO_2 losses from ruptures can be minimized by using in-line Emergency Shutdown Valves (ESV) that seal ruptured pipe segments within seconds after a pressure drop. ESV placement is important because the greater the distance between valves the more inventory is lost (Mahgerefteh et al., 2016).

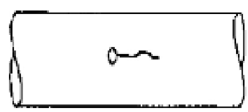
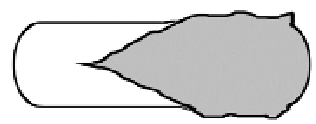
	Fracture mode	
Main features	Brittle	Ductile
Driving mechanism	Heat transfer Fracture toughness	Fracture toughness
Crack propagation	Slow, followed by catastrophe	Rapid
Crack arrest length	Unlimited	Limited
Energy dissipation	Instantaneous	Slow
Fracture shape		

Figure 7. Modes of pipeline fracture by specific mechanisms. Image obtained from Bilio et al. (2009).

From a safety perspective, CO_2 is not flammable and does not create an explosion risk. However, CO_2 is 1.5 times heavier than air and under the right conditions will settle into low lying areas posing asphyxiation risks particularly at concentrations above 15 percent. Physiological effects, however, can be seen at concentrations as low as 3 percent resulting in headaches (Harper et al., 2011). A historical example of CO_2 asphyxiation is near Lake Nyos, Cameroon where the lake turned over causing a large volume of CO_2 to run downhill smothering a small village (King et al., 1987). Lake Nyos serves as an illustrative example of the potential hazard; however, the amount of CO_2 emitted is likely more than several orders of magnitude larger than would be released from a pipeline rupture. During the last 20 years, the U.S. has not experienced any loss

of human life due to a CO_2 pipeline leak (PHMSA, 2017); however, there have been several incidents. In 2007, Denbury Resources had a well blowout near the Delhi Field, in northeastern Louisiana, which released large quantities of CO_2 killing several animals in the vicinity (Mississippi Business Journal, 2013). Traditionally, the natural gas industry has added mercaptans before transportation in order to help detect leaks and can be an additional safety measure taken by CO_2 operators (WRI, 2008). To date, CO_2 transport reports an excellent safety record with fewer accidents and fatalities per mile than both oil and natural gas pipelines (Table 1). Duncan et al. (2008) has noted safety incidents within the realm of CO_2 pipelines have been rare and are of little concern.

Table 1. Comparison of pipeline accidents and fatalities by commodity type from 1997-2016. Data was obtained from PHMSA (2017).

	Carbon Dioxide	Crude/Petroleum	Natural Gas
Pipeline Mileage	5,233	135,759	2,508,818
20 Years of Fatalities	0	21	275
Fatalities/1000 miles	0.00	0.15	0.11
20 Years of Accidents	1	27	768
Accidents/1000 miles	0.19	0.20	0.31

2.7 United States CO_2 Pipeline Infrastructure

The U.S. had 5,200 miles of CO_2 pipelines in 2015 with the capacity to transport approximately 24.8 Bt annually (PHMSA, 2017). Most of the infrastructure lies within three regions of the United States: the Permian Basin; the Rocky Mountains; and the Gulf Coast (Figure 8). The first CO_2 pipeline, the Canyon Reef Carriers, was built in 1972 in SACROC oil field in west Texas (van der Zwaan et al., 2011). Since the majority of the EOR projects have been located in the Permian Basin, the largest segment of CO_2 infrastructure has been built there. As cheaper natural sources of CO_2 were discovered, pipelines were able to expand to Wyoming, Mississippi

and Louisiana (Wallace et al., 2015). The CO_2 pipeline industry currently consists of a few dozen operators; however, three companies own the vast majority of the infrastructure: Kinder Morgan; Oxy Permian; and Denbury Resources (Wallace et al., 2015). The largest operators transport mostly natural sources of CO_2 and either own or have an ownership interests in the CO_2 supply (Global CCS Institute, 2014). The exception to CO_2 supply ownership is in the Rocky Mountain region. CO_2 pipelines in Wyoming receive a significant supply of CO_2 from natural gas processing and the pipeline network is made up of a handful of connected owners. In addition to their natural supply, Denbury Resources contracts with ExxonMobil for CO_2 supply in Wyoming. CO_2 pipelines in the Rocky Mountain region operate more like common carriers. However, the largest EOR producers own CO_2 supply, CO_2 pipelines, and operate the EOR field. Except for a few cases, most CO_2 pipelines currently transport in the supercritical phase (Global CCS Institute, 2014).

The NETL estimates that CO_2 transportation will need to expand over the next 20 years. With expansion comes important questions regarding how to best optimize proposed projects. There are two schools of thought regarding future CO_2 pipeline development each addressing whether appropriately-sized or oversized pipes should be constructed. Appropriately-sized pipes are designed with little to no capacity over that needed by the original supplier. While cheaper to construct (on a total cost basis), appropriately-sized pipelines do not allow for additional suppliers to buy in and will require additional pipelines to be built if supply increases. Oversized pipelines, while more expensive to build in total, would allow additional suppliers to transport CO_2 overtime without building extra pipelines and could lead to some economies of scale on a unit-cost basis. Wang et al. (2013) found constructing oversized pipelines is ideal when flow rate

increases are expected in the near term. If flow rate increases are not expected in the near term then oversized pipes will be underutilized. On the other hand, Mechleri et al. (2017) made a case for appropriately-sized pipelines designed in the United Kingdom. Due to the fossil fuel industry's decreasing role with increasing renewable deployment, Mechleri et al. (2017) suggests oversized systems are not needed because less CO_2 will be available in the future. Depending on how the industry chooses to organize itself moving forward, appropriately-sized versus oversized, will determine which companies are able to enter the market.

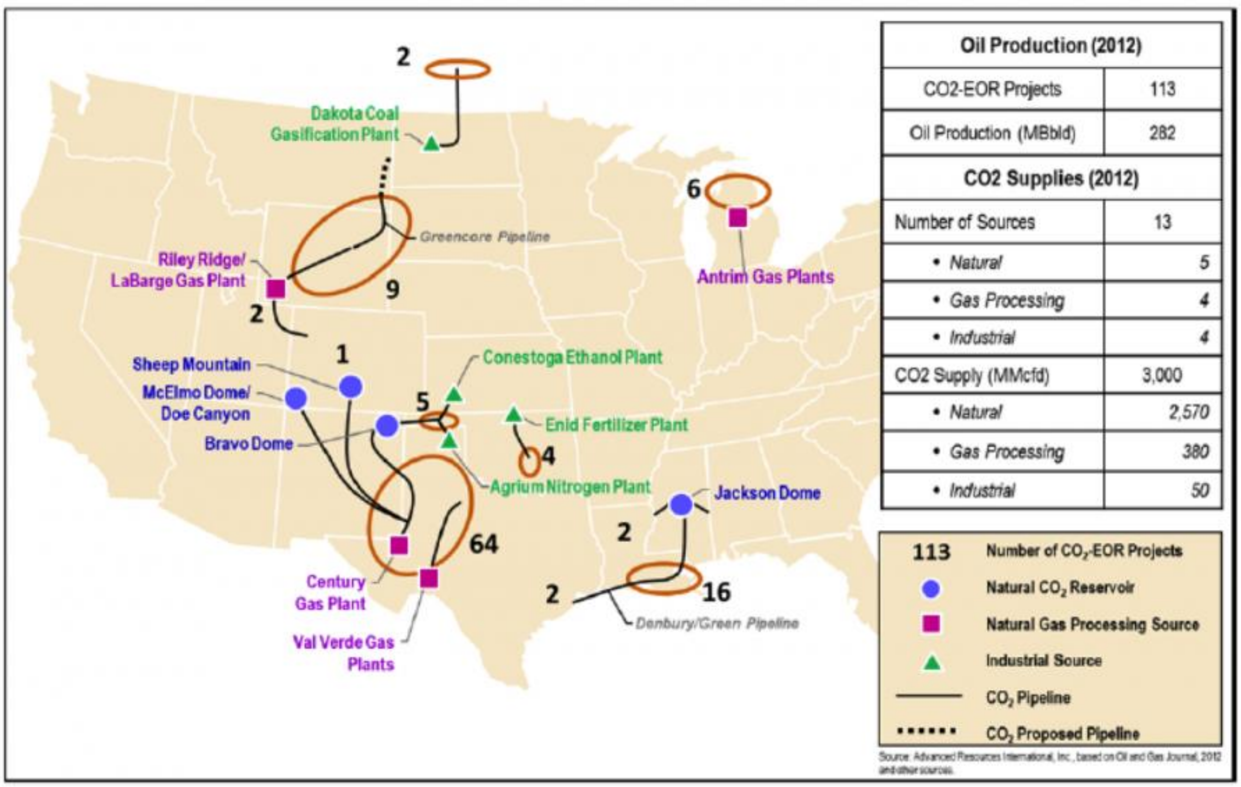


Figure 8. Map depicting the current CO_2 infrastructure in the U.S. Taken from Wallace et al. (2015).

2.8 Louisiana CO_2 Pipeline Infrastructure

Louisiana has approximately 330 miles of CO_2 pipeline composed of four individual segments with a total capacity of 38 MMt/yr, (Figure 9). As of 2017, these pipelines are all owned

by Denbury Resources and are all used by Denbury for CO_2-EOR primarily in east Texas. Denbury uses self-owned, naturally occurring CO_2 supplies from the Jackson Dome in Mississippi. However, one segment of this CO_2 pipeline, referred to as the Green Pipeline, has been transporting industrial CO_2 from a nitrogen plant in Geismar, LA since 2013 which supplies around 36 Mt/day (Table 2).

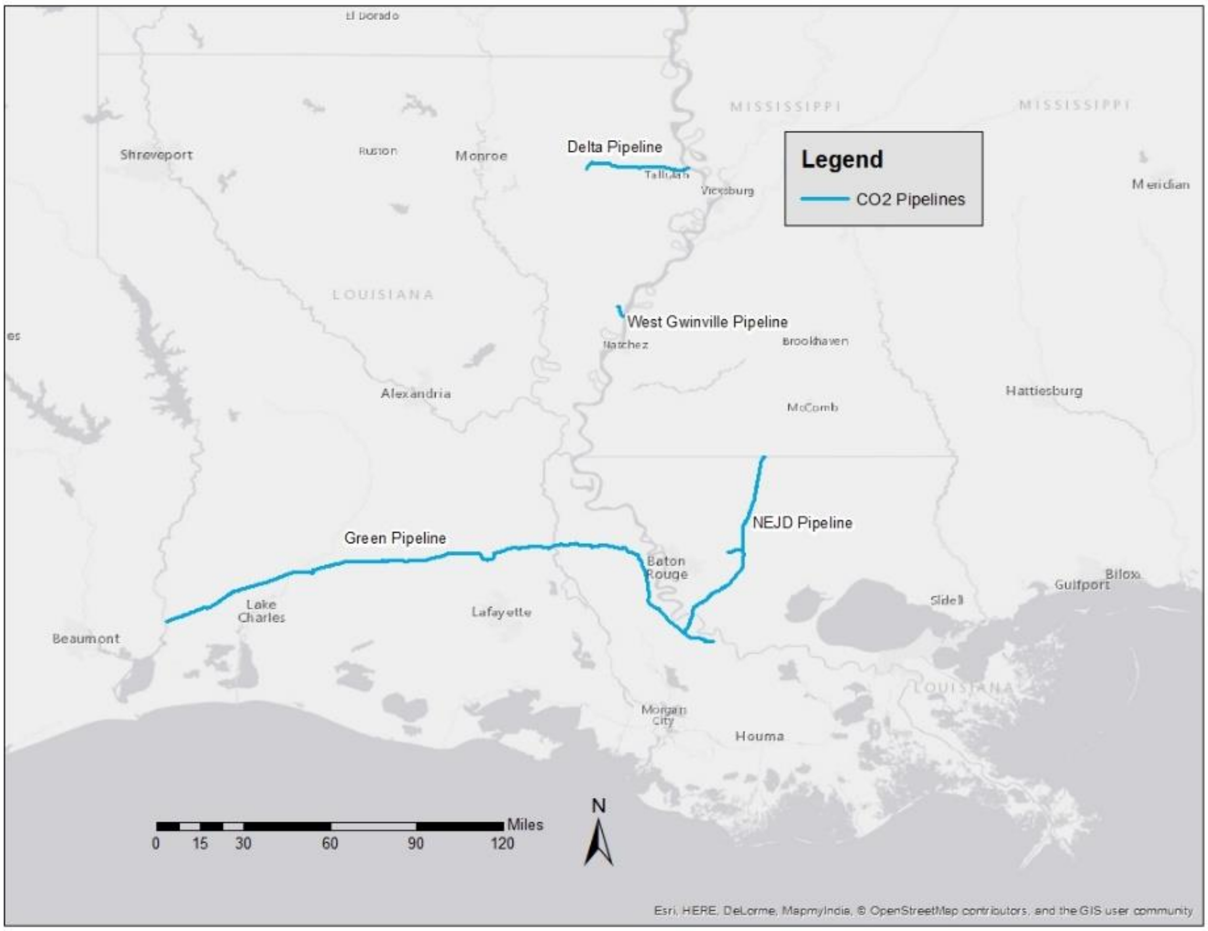


Figure 9. Current extent of CO_2 pipelines in Louisiana. Data was obtained from MAPSearch (2017) and map was created using ESRI (2017) ArcMap.

Louisiana's current CO_2 pipeline capacity is far below its EOR capabilities. The current pipeline system has been developed to specifically reach the Delhi field in the north or to transport CO_2 across the southern half of the state to oil fields in east Texas. There are no lateral

lines to meet oil fields in the south and the northern half of the state is completely devoid of CO_2 pipelines or any other areas between these two points. Future Louisiana CCS development will depend on who will develop the necessary new CO_2 pipeline infrastructure. Denbury Resources owns the only natural source of CO_2 in the region, so logically Denbury stands in a position to be the incremental developer. If other companies wanted to develop Louisiana EOR projects, they would have to contract with the industrial sector in order to purchase CO_2 and likely contract with Denbury to interconnect with their developed CO_2 network. Regardless of who, additional CO_2 pipelines will be needed in Louisiana in order to keep pace with EOR (Ambrose et al., 2009).

Table 2. Basic description of CO_2 pipelines throughout Louisiana, U.S.A. All are owned by Denbury Resources. *The West Gwinville pipeline was purchased in 2007 as a natural gas line and then converted to CO_2.

Pipeline	Built	Diameter (in)	Distance (mile)	Capacity (Mt/day)	Origin	End
Delta	2009	24	37.7	33.1	Jackson Dome, MS	Delhi Field, LA
NEJD	1986	20	91	20.2	Jackson Dome, MS	Donaldsonville, LA
Green	2010	24	196	52.1	Donaldsonville, LA	Houston, TX
West Gwinville	1963*	16	4.8	9.5	NEJD	Lake St. John, LA

CHAPTER 3: CO_2 PIPELINE DEVELOPMENT COSTS

3.1 Introduction

The costs of building CO_2 pipelines are considerable and represent a barrier to market entry. In 2014, a 140 mile, 36 inch natural gas pipeline in Washington state cost $822 million to construct. On a per unit distance basis, recently reported development costs can range from $579,000/mile for a 4 inch pipeline in Colorado, to over $24,000,000/mile for a 42 inch pipeline in New York (Smith, 2014). The large financial investment inherent in building pipelines means operators must have an accurate estimate of the proposed project costs before construction can begin. While there are considerable volumes of cost data on natural gas pipelines, there is very little information on CO_2 pipelines given their small number and lack of oversight (Nordhaus and Pitlick, 2009).

Several models exist to estimate CO_2 pipeline costs (Knoope et al., 2013); however, all models are based off prior natural gas pipeline costs. This may not be an issue since there are only subtle differences in design specifications and engineering principles. As such, Knoope et al. (2013) have found a general cost and design characteristic common across both natural gas and CO_2 pipes: namely their ability to take advantage of economies of scale. While large projects have a larger cost, the unit cost of transport falls as scale increases. The models have been developed using different functional forms (linear, quadratic, etc.) and can incorporate a variety of parameters (distance, volume, pressure drop). Costs are divided into CAPEX and OPEX, and CAPEX are further broken down into construction labor, materials, miscellaneous and ROW. Some CO_2 pipeline cost models-like the one utilized by the Energy Information Administration (EIA)-use regional considerations to account for variability of terrain, climate, availability of

materials and the occurrence of the intended product. Cost models are optimized using polynomials in order to optimize goodness of fit. Other models utilize separately-estimated individual parameters to individually predict each cost category and their regional differences (McCoy and Rubin, 2008). Due to the variety of models available, a range of costs can be found for a given set of specifications (Knoope et al., 2013). Model differences lead to considerable variation in cost estimation.

This study will employ the NETL (2014) engineering-economic model (NETL model) in order to estimate south Louisiana CO_2 pipeline costs. The NETL model uses a range of parameters related to project-specific attributes (distance, volume, pressure drop, financial matters, etc.). The NETL model facilitates a cost-minimize estimate given the project specific inputs by calculating the appropriately-sized pipe, including necessary compression, using basic fluid dynamics equations.

3.2 Methods

Distance and capacity primarily drive CO_2 pipeline costs. Industry rule of thumb suggests most CO_2-EOR projects need to be within 100 miles of the CO_2 point source (Middleton et al., 2014). An additional 5 MMt of incremental CO_2 pipeline capacity will be needed to facilitate CO_2-EOR. In order to model these outcomes for south Louisiana EOR, these requirements were compared to a number of sensitivities over a range of capacities (0.5 to 5MMt, at 0.5MMt intervals) over a range of distances (10 to 100 miles, at 10 mile intervals).

A key input for the NETL (2014) model is to decide which of the three offered methodologies to use to determine cost; the present study used the methodology developed by McCoy and Rubin (2008). The McCoy and Rubin method is separated into two components: 1) an

engineering component used to determine pipe diameter and necessary compressors and 2) a cost component built using FERC natural gas pipeline data. The engineering model considers the density of CO_2 at the specified pressures, frictional loss along the pipe, and pressure drop along the terrain. Once diameter has been determined, the economic model determines cost based on FERC filings. McCoy and Rubin (2008) developed the cost model using regression analysis using each of the four cost categories as independent variables with additional correction factors based on pipeline location. The McCoy model uses an iterative process by modeling different sizes of pipe using a varying number of compressors in order to find the least cost solution. Other inputs used in generating costs can be found in Table A.1.

Although the McCoy model calculates cost based on previously completed natural gas pipelines projects, the pipeline design specifications are based on the physical phase of supercritical CO_2. The model accounts for the differences between the two commodities by applying an additional 12-25 percent correction factor to pipes larger than 12 inches to account for the costs of higher quality materials used in transporting supercritical CO_2 (Section 2.3) and subsequent construction labor. One limitation of the McCoy model is it assumes X70 carbon steel pipe will be used and cannot incorporate other grades of steel. Regardless, Knoope et al. (2013) found the McCoy model yields in a moderate estimate when compared to other models, and Serpa et al. (2011) has shown the McCoy model is superior to polynomial models when trying to predict the cost of completed CO_2 projects.

3.3 South Louisiana Pipeline Cost Estimates

The estimated cost to build a new CO_2 pipeline in south Louisiana, using the NETL model, ranged from \$10.6 million, for a 10 mile, 8 inch pipeline transporting 0.5MMt annually (\$1.06

million per mile) to \$121 million for a 100 mile, 20 inch pipeline transporting 5MMt annually (\$1.2 million per mile). Estimated CAPEX generally increase linearly with respect to distance but fluctuations were due to using differing size diameter pipes (Figure 10A). If the CAPEX line fluctuates up, a larger diameter pipe is needed, whereas, if the line fluctuates down, a smaller diameter pipe is needed. OPEX increase linearly with distance, except when the number of compressor pumps needed changes, see Figure 10B 3.5 MMt at 80-90 miles. OPEX increase with additional compression and decrease when compression is removed. Overall, larger projects had a lower cost when viewed as cost per unit mass transported, (Figure 11). It is important to note an 80 percent capacity factor was used in this analysis (Table A.1.) and if average transported capacity is less than 80% then the costs associated with transporting CO_2 will increase.

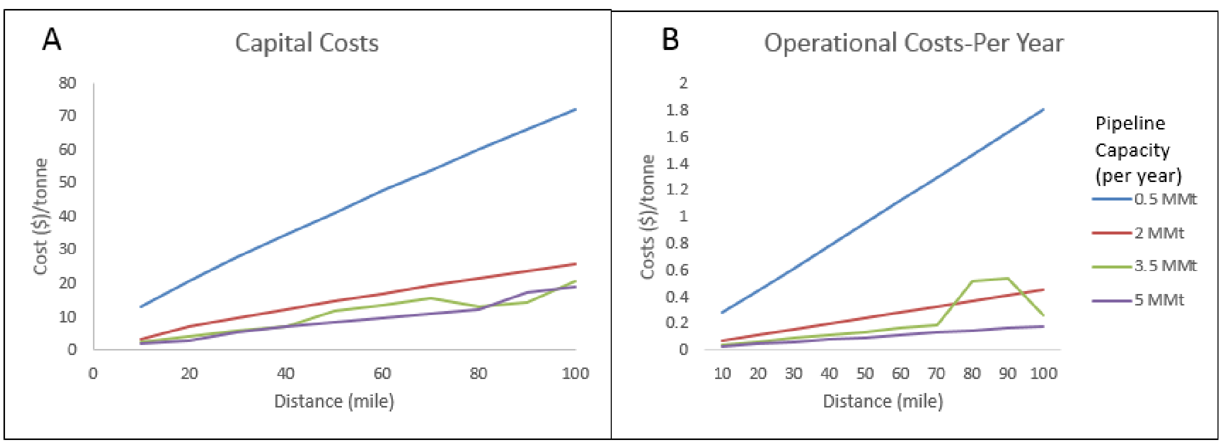


Figure 10. A) CAPEX as a cost per unit CO_2 transported B) OPEX per year on a cost per unit transported.

There are small differences in how CAPEX were distributed between the four cost categories based on the size of the pipeline project. Labor was the largest contributor to large (5MMt) CO_2 pipelines at 38 percent, followed by materials (29 percent), miscellaneous (23 percent) and ROW (9 percent). The cost of materials was the largest contributor to smaller

(0.5MMt) pipelines at 34 percent, followed by labor (30 percent), miscellaneous (27 percent) and ROW (8 percent).

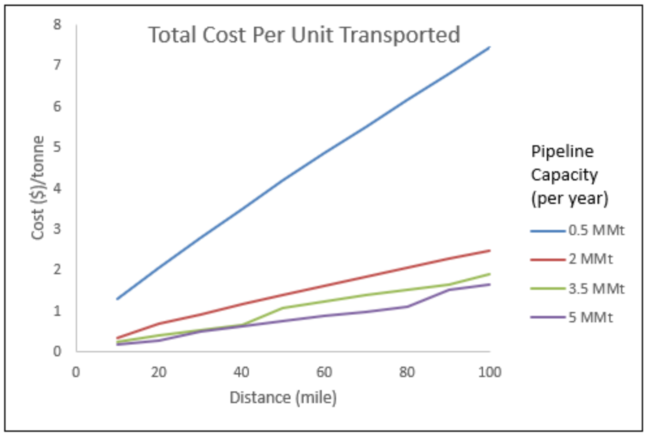


Figure 11. Total cost of various sized projects over various distances.

3.4 Cost Estimation Results and CO_2 Pipeline Development

CO_2 pipeline development costs are estimated to be $121 million versus $63 million to transport 5MMt and 0.5MMt 100 miles, respectively. Estimated CO_2 project costs exhibit economies of scale as shown in Figure 11. Economies of scale are estimated to be 5:1 or 25 percent: larger pipelines cost more per mile but can transport substantially more CO_2. Distance and diameter are also important cost drivers despite these scale economies, increasing the distance continues to increase the total cost and cost per unit transported, but this too is dependent on the size of the project. For short distance pipelines (<10 miles), the cost differential between small and large capacity pipelines is minimal. Over longer distances, distance is estimated to have a relatively smaller impact on larger diameter pipeline costs than for smaller CO_2 pipeline segments. Capacity has a small impact on costs per segment less than 10 miles but is important for pipe segments spanning longer distances.

Total costs (CAPEX and OPEX) increased mostly linearly with distance for all sized projects. The only exception arises in pipe segment modelled at a 3.5MMt, 80-90 miles configuration. During this interval, there is an abrupt rise in OPEX during the 80-90 mile interval due to added fuel costs associated with running an additional compressor (Figure 10B). In all other cases, no compression is needed beyond the time of capture. At all distance intervals, except 80 and 90 miles, the least cost pipe diameter is 16 inch without a compressor; however, at 80 and 90 miles the model predicts a 12 inch pipe is acceptable but with one compressor. The model, by default, had minimized the CAPEX but significantly increased the ongoing OPEX over the 30 year project life due to the ongoing costs associated with running a compressor (Table 3, specifically "Minimized CAPEX"). When OPEX is minimized, by specifying the model used no additional compression, the NETL model determined a 16 inch pipe is adequate for 80-90 miles, which increased the CAPEX by $15 million but decreased the OPEX by $32 million over 30 years, bringing the overall 30 year project total cost down (Table 3, see specifically "Minimized OPEX"). Determining which project phase (CAPEX or OPEX) to minimize costs will depend on how the pipeline network is set up (oversized or appropriately-sized). Unless specified by the user, the NETL (2014) model does not present results for oversized pipeline projects.

Table 3. Specifications for a 3.5 MMt, 80 mile project when minimizing costs for either CAPEX or OPEX.

	Minimized CAPEX	Minimized OPEX
Diameter (inch)	12	16
Number of Compressors	1	0
Total CAPEX ($)	45,203,535	60,358,718
Total 30 Year OPEX ($)	53,941,246	21,972,564
Total 30 Year Cost ($)	99,144,781	82,331,282

The NETL model was developed using natural gas cost data and the configuration of natural gas pipeline systems which does not recognize differences in how the various cost components contributed to CO_2 pipeline CAPEX. CO_2 pipeline CAPEX percent contributions from the miscellaneous and labor components decrease relative to comparable natural gas pipe segments, whereas, material contributions increase. Unlike natural gas pipelines, CO_2 pipelines tend to have a higher relative material cost contribution, (29-34 percent) relative to natural gas systems (13 percent). The difference in material percent contribution to CAPEX is attributed to the need for higher quality pipes which can handle the increased pressure when transporting supercritical CO_2 (WRI, 2008). A correction factor is used in the NETL model to account for these material differences. The correction factor was not applied to the miscellaneous component since the component is mostly a procedural cost and is unlikely to change with commodity and thus explains the decrease in percent contribution. Interestingly, even though the same correction factor is applied to both labor and material, labor relative percent contribution decrease relative to natural gas pipelines (30-38 percent vs 47 percent) while material shares increase (29-34 percent versus 13 percent) relative to natural gas pipeline configurations. These differences may be attributed to the regional correction factors or based on project size. Material and labor relative shares also differ by the size of the CO_2 project. Other things equal, project capacity increases total cost but in a proportionately uniform fashion across all relative cost components. Labor cost decreases are expected with smaller projects which should also exhibit a comparable decrease in material costs. But the relationship between cost and pipe diameter is logarithmic and exhibits economies of scale (i.e. unit cost falls as diameter increases). Material and labor costs changed at different rates since the contribution of pipeline materials to the

overall cost decreases with increasing size when compared to labor; a result not surprising given the capital intensive nature of pipelines and their scale economies.

CO_2 pipeline cost models and estimates rely exclusively on data from comparable natural gas pipeline developments. There are, however, some differences in these two types of pipes with the main difference being attributable to CO_2 pipes requiring higher grade materials for supercritical phase CO_2. CO_2 pipelines, however, are estimated to exhibit economies of scale leading to an argument that developers should consider the marginal cost of additional capacity when designing their projects (Wang et al., 2013). In addition, OPEX is sensitive to compression requirements: long transmission lines or steep terrain would necessitate additional compressors. Ideally, developers can minimize costly compression investments (and OPEX) by developing smaller segments or increasing pipe diameter. The cost estimation method presented here provides a rough starting point for project development and key insight for the differences based on the size of projects.

CHAPTER 4: THE FEASIBILITY OF REPURPOSING NATURAL GAS PIPELINES

4.1 Introduction

Carbon capture (Leung et al., 2014) and EOR (Holm and O'Brien, 1971) are both mature; however, the infrastructure linking CO_2 sources to sinks, or users, is seriously limited. There are currently 5,200 miles of CO_2 pipelines in the U.S.; an investment that pales in comparison to the 300,000 miles of natural gas transmission infrastructure (Dooley et al., 2009). The majority of the active CO_2 pipelines are located in west Texas for EOR purposes. Expectations are that the Rocky Mountains and the Gulf Coast regions will be the next important areas for transportation development. Wallace et al. (2015), for instance, predicts 1,000 miles of CO_2 pipeline will need to be built every year until 2030 in order to keep up with the pace of EOR potentials in both of these regions. Yet, as was demonstrated earlier, CO_2 transportation development will be tempered by high construction costs; particularly as those costs meet or exceed $2 million/mile. In addition, CO_2 pipelines will likely be considered relatively new and novel types of development that could lead to regulatory and environmental review and permitting delays. Further, there is some question regarding the extent to which CO_2 pipelines would face some form of public opposition comparable to those arising for the Keystone XL and the Dakota Access pipelines. However, in the face of climate change, and the urgency in developing bona fide solutions, this type of opposition may be limited.

One potential option that may reduce overall development cost and effort may be to reuse existing older or underutilized natural gas infrastructure (Rabindran et al., 2011; Noothout et al., 2014; Onyebuchi et al., 2017). Louisiana, for instance, has over 24,000 miles of natural gas pipelines in 2016 (Figure 12, PHMSA, 2017). Further, Louisiana natural gas production has

declined dramatically since the 1970s (Figure 13) raising questions about the continued usefulness and utilization of these natural gas pipes, many of which are nowhere near the end of their physical useful lives.

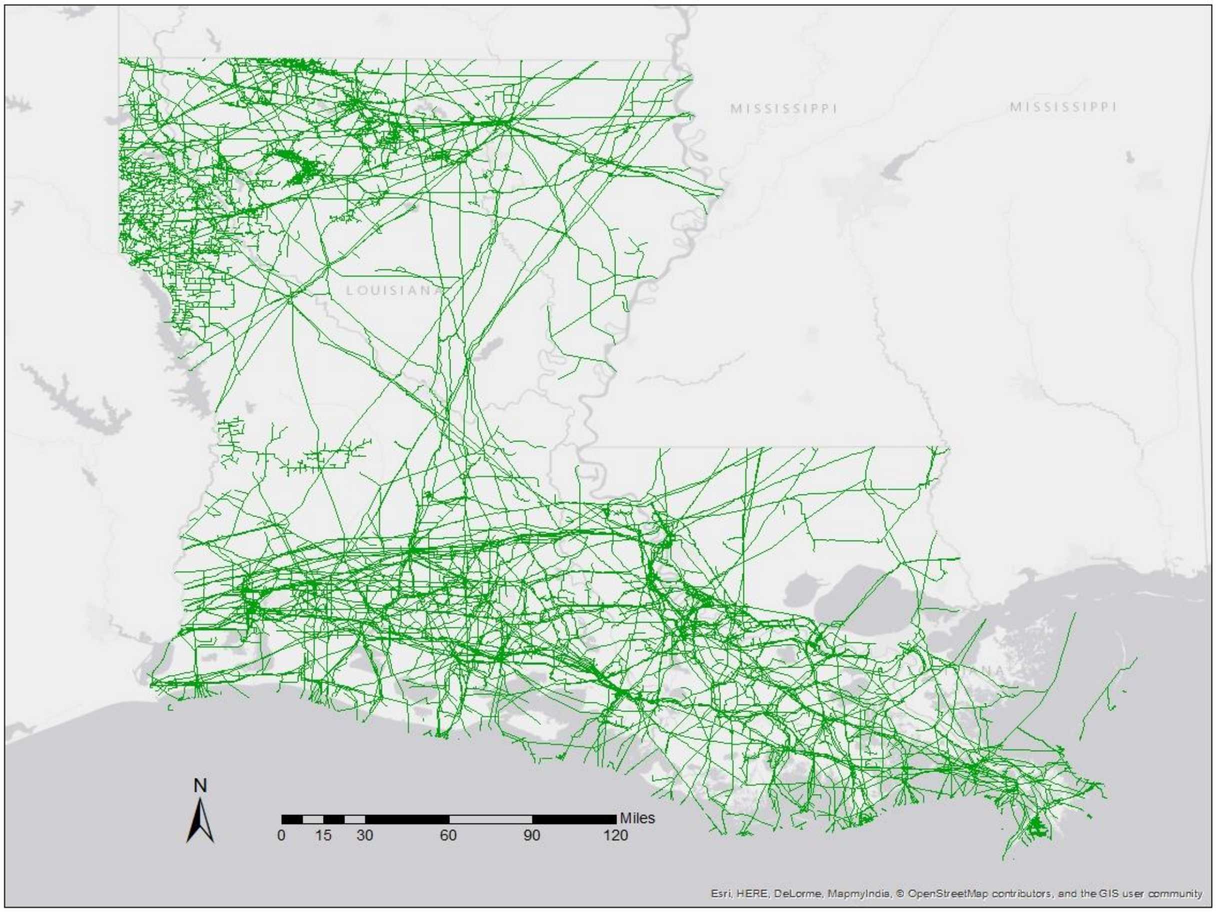


Figure 12. Louisiana natural gas infrastructure. Data obtained from MAPSearch (2017).

There are a variety of incentives for using or repurposing existing natural gas pipelines for CO_2 transport. First, repurposing pipelines reduces material use requirements, which would otherwise be extracted from the earth, reduces waste entering landfills, and reduces potential land degradation. Second, repurposing natural gas pipelines reduces expensive entry costs for CO_2 projects or potential CO_2 transportation companies (Herzog, 2011). Third, the conversion of existing older natural gas pipelines may reduce harmful methane emission which are a significant

contributor to climate change and ultimately loss revenue for the natural gas operator (Kirchgessner et al., 1997).

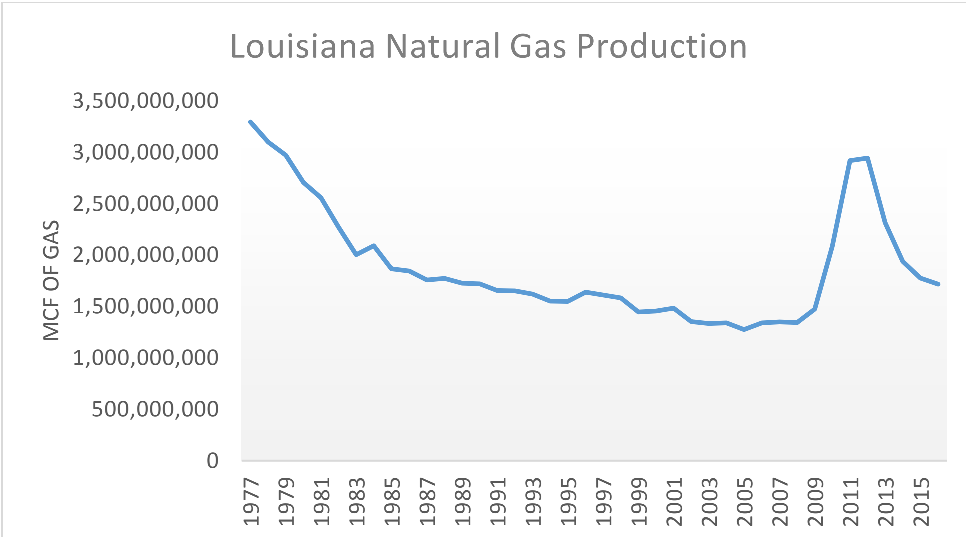


Figure 13. Louisiana natural gas production from 1977-2015. Data retrieved from SONRIS (2017).

There are a number of special considerations for repurposing natural gas pipelines for CO_2 transport use (Seevam et al., 2010; Serpa et al., 2011; Noothout et al., 2014; Brownsort et al., 2016). First, the physical properties of CO_2 and natural gas are fundamentally different (Averill and Eldredge, 2012). Transporting CO_2 is most economical in its supercritical phase which occurs at or above 1,070 psi while natural gas is generally transported at lower pressures which can range between 188-1,493 psi (Rabindran et al., 2011). Any pipeline expected to move CO_2 at a supercritical phase would need to be rated well above 1,070 psi to account for the pressure drop dictated by the terrain and the temperature fluctuations of the region. Suggested operating pressures used in the transportation of supercritical CO_2 range between 1,200-2,200 psi (WRI, 2008). CO_2 could be transported in its gaseous state if natural gas pipelines are not rated for supercritical CO_2 level pressure, but the economies of doing so are less attractive.

The source of CO_2 must also be considered since differing sources of CO_2 can have varying impurities including H_2S, H_2O, N_2 and CH_4. These impurities can have several effects on the pipeline which include reducing available transport capacity, corrosion and, in the event of a leak, increased toxicity. Even an impurity as benign as water can react with CO_2 to create carbonic acid which has been shown to corrode carbon steel up to 10mm/yr; however, these are not unknown challenges (Seevam et al., 2010; Choi et al., 2010). Existing CO_2 pipeline operators understand the risks of pipeline corrosion and generally contract with CO_2 suppliers for purities of at least 95 percent (Rabindran et al., 2011; Noothout et al., 2014; Herron and Myles, 2013). Thus, as a general rule, it is very likely that existing natural gas pipelines can be repurposed if: 1) the CO_2 supply is dry, and 2) the pipeline can accommodate the expected pressures (Serpa et al. 2011).

There are a number of regulatory requirements associated with natural gas pipeline conversions. The EIA monitors conversion projects taking place around the country (US EIA, 2017). Currently, the most publicized projects are conversions of natural gas projects to oil or liquids to accommodate new unconventional production, while details on CO_2 conversion projects gather little media attention. Public opposition to these conversions have arisen. One of the more contentious conversion projects involves the Tennessee Gas Pipeline Company infrastructure crossing Kentucky (FERC Docket No. CP15-88). Tennessee Gas petitioned to convert their natural gas pipeline to natural gas liquids while also reversing the flow. Stakeholders voiced concerns during the comment period about the age of the pipe, the increased pressure and ultimately potential spills which could contaminate aquifers and foul agricultural land. The main concerns stem from the pre-1950s method of heating pipe segments before bending which has been shown to cause wrinkle bends. Using the relic bending technique is thought to diminish

the strength of the pipe. Ultimately, residents feel the pipe slated for conversion is inadequate for repurposing because the standards and methods used during 1940s construction are inferior to today's standards. The implications of recent conversion activity have caused stakeholders to call for increased regulatory oversight on conversion projects.

Historically, operators have relied on 49 CFR Part 195.114 which specifies which pipelines are acceptable to be repurposed. But now the increasing number of pipeline conversion projects, eleven since 2009 (only one of which was CO_2), have sparked regulatory agencies to issue new guidelines for the process. The PHMSA Docket No. 2014-0040 has provided new guidance for re-evaluating pipelines in consideration for transporting different commodities. The main points for the new PHMSA guidelines are: 1) any change over $10 million must be reported to PHMSA, 2) operators must ensure CO_2 streams do not contain corrosives (impurities), 3) operators should conduct internal pigging, inline inspections and/or hydrostatic tests, 4) MAOP must be re-established, and 5) pipes with no history record, a history of failure, unknown welds and/or current SMYS greater than 72 percent should not be considered. While the PHMSA only needs to be notified if the conversion project is over $10 million, the guidelines are applicable to all conversion projects.

Pipeline conversion applicability is a considerable challenge in repurposing natural gas pipelines to CO_2 transport. Identifying candidate conversions is a complex task given that various factors can impact utilization such as region, prices, economic factors and weather trends.[1] Annual utilizations are often less than the design capacity, but may test capacity levels on individual days. Additionally, pipelines are broken into many smaller segments and natural gas

[1] https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/usage.html

can enter (receipt) or exit (delivery) at various points along the route. For example, pipeline A-B-C-D might have a design capacity of 100 tonnes per day, but if 50 tonnes of CO_2 enters at point A and C, and exit at B and D, the total delivered volume is at capacity; however, the pipeline is only being utilized at 50 percent.

Another major hurdle in determining ideal conversion/repurposing candidates is ascertaining the pipe segment's MAOP. In 2012, PHMSA Docket No. 2012-0068 proposed to start requiring operators to have verifiable and traceable documentation for the MAOP of older pipelines in HCAs and Class 3 and 4 areas[2]. However, this information is not publicly available and would only encompass a small percent of the total infrastructure. The National Pipeline Mapping System (NPMS), tasked with keeping geospatial records of all the pipelines in the U.S., have not traditionally gathered data on MAOP. In 2014, PHMSA moved to add MAOP to NPMS reports through Docket 2014-0092. The industry argued in its comments during the rulemaking that the new reporting standards would create an undue financial burden and pose a national security threat if placed in the wrong hands. The proposed guidelines underwent several comment periods and revisions but as of late 2016 there has yet to be a final ruling. Although knowing the MAOP can be informative, there is still no database accessible to the public or government regulators which contains MAOP information or the components needed to calculate MAOP. Currently, this information rests solely with individual operators.

The repurposing of natural gas pipelines to transport CO_2 has been suggested by numerous authors and organizations as a way to cut costs. Several government agencies have

[2] Class designations are determined by proximity to population centers. The higher the class designation the lower the value. See 49 CFR 192.111.

even gone as far as providing guidelines for the minimum standards. However, no study has developed a methodology to use as a screening tool in order to ascertain the possibility of converting natural gas pipe segments to CO_2 transport. A model defining such a screening tool will be provided later.

4.2 Case Studies

Repurposing pipelines is still a relatively new idea, and the details of the few successful CO_2 projects are often sparse but examining case studies can provide valuable insight. The only example of a natural gas to CO_2 conversion in the U.S. is the West Gwinville Pipeline operated by Denbury Resources. The 16 inch natural gas pipeline spanning 50 miles in Mississippi was purchased by Denbury from the Southern Natural Gas Company (SONAT) and then converted to carry CO_2 for EOR purposes. The pipeline segment sale was mutually beneficial to both SONAT and Denbury. SONAT had strong interest in selling the pipe system since production had declined thereby lowering its natural gas transport revenue. At this time, OPEX had begun to exceed the annual revenue generated from transport undermining SONAT's bottom-line.[3]

Denbury's cost savings for purchasing and repurposing the natural gas pipeline included avoided right-of-way purchases, materials, and construction labor expenses. Denbury expected the total project cost to be around $5.2 million. Given the 50 miles of repurposed pipe and expected 3.5MMt/yr capacity, the NETL model predicts the cost of building a new CO_2 pipeline would have been about $41 million: a savings of over $35 million. While building and converting CO_2 pipelines are not strictly overseen on the federal level, the West Gwinville Pipeline is a special

[3] Several million dollars' worth of upgrades were also needed to keep the pipeline in regulatory compliance adding to SONAT motivation for selling.

case. Denbury and SONAT had to go through FERC federal permitting procedures. According to section 7(b) of Natural Gas Act Section 157.7 and 157.18, Southern Natural Gas had to apply for “Abandonment and Sale” of the pipeline to Denbury (April 26, 2006 CP06-145). As a utility company, SONAT provides a necessary product to the public and cannot legally stop service to the communities being supplied with gas. During the review process, stakeholders submitted “Notice of Interventions” to ensure the sale would not negatively impact their service. As part of the purchase agreement, Denbury agreed to build a smaller pipeline to continue natural gas service to the small community in northern Mississippi. The West Gwinville pipeline has shown conversion projects must be mutually beneficial and will have to go through the FERC if the pipeline was originally a common carrier.

Internationally, there are two additional CO_2 conversion projects of interest. The “Organic Carbon dioxide for Assimilation of Plants” (OCAP) Pipeline located in the Netherlands is a conversion project in operation since 2004. Originally an oil pipeline, the OCAP had been out of service for nearly 25 years before being repurposed to transport CO_2. The 26 inch, 51 mile pipeline transports CO_2 in the gaseous phase at 101-304 psi (Global CCS Institute, 2014, Ros et al., 2014) and supplies 300 Mt per year of CO_2 captured from hydrogen production to local greenhouses (van Berkum, 2009). The No. 10 Feeder in the United Kingdom is a natural gas pipeline slated to transport CO_2 captured from the industrial sector and used in offshore CCS. The No. 10 is a 36 inch, 174 mile natural gas pipeline originally constructed for a MAOP of 1,160 psi. With an error margin less than 100 psi, the proposal calls for transporting CO_2 at 493 psi due to the risk of two phase flow during extreme temperature fluctuations (Element Energy, 2014). Supercritical CO_2 was not needed in either case because the projects’ end goal are not EOR. The

majority of modifications on the No. 10 Feeder are for the replacement of 13 block valves. The No. 10 Feeder purchase and conversion is estimated between $71-102 million, but the cost to build new modeled by the NETL showed the project would have cost $217 million (ScottishPower CCS Consortium, 2011). Even though the most economical way to transport CO_2 is in the supercritical phase, companies have found it acceptable to transport in the gaseous phase if repurposing pipelines. Gaseous transport may be an important aspect for repurposing natural gas infrastructure because natural gas is generally transported at lower pressures and thus will increase the number of opportunities for repurposing.

4.3 Data and Methods

This study utilizes a concentrated geographic scope defined as Louisiana's southernmost 38 parishes (collectively "south Louisiana"). This geographic region was selected since it is home to the majority of statewide industrial CO_2 emission sources, as well as an abundance of potential oil fields that could utilize EOR. South Louisiana also has an extensive set of existing natural gas pipeline infrastructure (Dismukes et al., 2017). This study will combine several geospatial datasets to determine which pipelines are ideally situated near both a source (industrial emissions) and sink (EOR fields) (Section 4.3.1). The list of potential pipelines will be systematically narrowed by each segment's capacity to carry CO_2 (Section 4.3.2) and depending upon pipe material (Section 4.3.3). Finally, only pipelines within parishes with declining gas production will be considered (Section 4.3.4). Once a complete list of candidate pipeline segments has been selected, their specifications will be incorporated into the NETL model to determine the avoided cost of building these candidate pipelines new (Section 4.3.5). Figure 14 provides an overview of the screening process.

Figure 14. Step by step screening methods flow diagram.

4.3.1 Selection by Geographical Location

There are 66 industrial CO_2 point sources (sources) in south Louisiana based upon data included in the 2014 USEPA GHG mapping tool (US EPA, 2017). A prior study identified 62 potential EOR fields (sink) (Advanced Resources International, 2006) that were then extracted from the LDNR SONRIS GIS Access database based on field IDs (SONRIS, 2017). Natural gas pipelines from MAPSearch (2017) were then selected as candidate segments to link their earlier identified sinks and sources. Table 4 provides sources of data and Figure 15 provides a map identifying all sources, sinks and repurposing pipeline segment candidates. The average distance between sources and sinks is estimated to be 11 miles which was used as a screen for evaluating candidate conversion pipeline segments. Thus, only pipelines within 10 miles of source and sink were considered. Higher thresholds for pipe selection are not plausible since it would be more economical to build a new pipeline straight to the closest sink rather than buy a repurposed pipeline and then build more than 10 miles of interconnecting pipe. There are a number of candidate segments within 5 miles of both a source and a sink. However, not all pipelines within the 10 mile buffer make practical sense. The list of potential candidates was systematically narrowed further by 1) eliminating segments which were integral to an operator's overall system, 2) were nonsensical (i.e. within the 10 mile buffer but would provide no useful route) or 3) where the distance needed to tie into the repurposed pipeline was greater or equal to the distance of

building a new pipeline straight from source to sink (see Figure A.1 and Figure A.2 for clarification).

Table 4. Data sources for proximity screen.

Data Layer	Source	Number of Features
CO_2 Industrial Sources (Sources)	US EPA (2017)	66
Candidate EOR Fields (Sinks)	Identified in Advanced Resources International (2006) and extracted from SONRIS (2017)	62
Natural Gas Pipelines	MAPSearch (2017)	5,112

4.3.2 Selection by Capacity

MAOP, as noted earlier, is not reported on a disaggregate basis. Thus, a proxy method will need to be utilized in order to develop an accurate assessment of the transportation capacity available from the candidate segments. Jaramillo et al. (2009) found the five EOR projects in their study ranged in daily CO_2 purchases of 0.6-11.5 Mt. The CO_2 pipelines operated by Kinder Morgan, which have an outside diameter (OD) that vary from 16-30 inches, have transport capacities ranging from 5-62 Mt per day. To be conservative, this study only considered pipelines able to sustain an EOR project which would require a given segment's capacity be between 12-62 Mt CO_2 per day. The capacity of natural gas pipelines to transport CO_2 can then be calculated by using the Ideal Gas Law Equation given as (2):

$$PV=nRT \tag{2}$$

where P=Pressure, V=Volume, n=the amount of gas (moles), R=universal gas constant, and T=temperature. Using Equation 2 assumes CO_2 and methane are ideal gases but ideal gases are theoretical and do not exist in real life. But the Ideal Gas Law can be used to provide a rough

approximation of the amount of CO_2 pipelines can carry (McAllister, 2005). Equation 2 will require proxies for P (MAOP) and n (Capacity) while variables V, R and T are assumed to be constant.

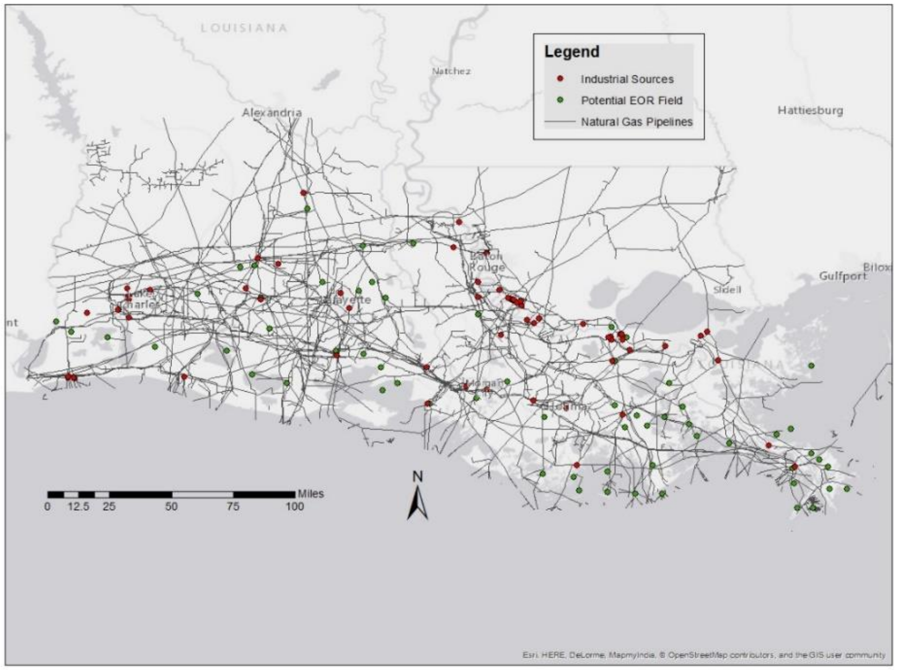


Figure 15. Graphical view of all natural gas pipelines, industrial sources and potential EOR fields in southern Louisiana.

There is no single source of data for MAOP, or the parameters needed to calculate MAOP (steel grade, wall thickness), of individual pipeline segments. The only information publicly available is the OD.[4] A proxy for MAOP can be developed based on previously built pipelines. Using applications from the FERC Approved Major Pipeline database, a list was compiled of pipe OD, capacity and associated MAOP for projects completed during 2009-2017 (FERC, 2017). Linear regression was used to determine there is no a relationship between OD and MAOP (β_1=5.62, t-stat=1.15, p=0.2552, R^2=0.033). Without a significant relationship, average pipeline MAOP will be fed into the NETL model to determine if actual operating conditions differ in cost from the

[4]Pipe OD was gathered from the NMPS (2017) when missing from MAPSearch (2017).

ideal conditions (1,200-2,200 psi) suggested in the literature and modeled in Chapter 3 using the same inputs from Table A.1 (e.g. 80 percent capacity, etc.). The resulting MAOP information will act as the proxy for Pressure in Equation 2.[5]

Total system capacity for a given operator is publicly accessible but is an unhelpful metric for the purposes of studying individual segments. According to 18 CFR 284.13, interstate and major non-interstate pipelines must post design and operational capacity for meter stations on their informational postings website. Segment capacity, generally measured in dekatherms, (dth (million btu)), or in a few cases thousand cubic feet (Mcf), can be inferred by finding meter stations connecting of interest pipe segments. Operational capacity data gathered from informational postings will act as the proxy for the amount of gas (n) in Equation 2. By using the FERC MAOP for pressure and the informational postings for n (capacity), *ceteris paribus*, Equation 2 can be manipulated to determine the amount of gas a segment can carry at varying pressures. The total amount of CO_2 each segment can carry will be calculated using the Ideal Gas Law at the lowest average MAOP found for pipelines constructed during 2009-2017 (gaseous phase).

4.3.3 Line Segment Selection by Pipe Characteristics

As previously stated, limited spatial information is available for specific segments. However, gathering and transmission pipe information can be inferred from 2016 PHMSA Annual Reports. Operators are required to report miles of pipe for each material category (steel, cast iron, wrought iron, and plastic), the number of miles for cathodic protection and coatings, and the number of miles by decade installed. Candidate segments are limited to carbon steel

[5] In the event that an unusual OD had no MAOP data from FERC applications (e.g. OD 12.75 in), the lower MAOP of the next higher and lower OD was chosen.

pipelines, constructed after 1950 with cathodic protection and coatings since these pipe materials are viable for high pressure pipe. The 2016 annual reports will be searched by operator to find what material the pipes are potentially constructed with, any protections in place and what decade the pipes were most likely built. Since PHMSA annual reports do not contain spatial information, only operators with high percentages of bare steel, cast/wrought iron pipes and pipes installed before 1950, or low percentages of corrosive protections will be eliminated. This resulted in no pipe segments being eliminated from the analysis.

4.3.4 Selection by Natural Gas Production

Detailed flow data, on a per segment basis, is largely unavailable making a per segment utilization analysis difficult. Transmission data can be gathered from the daily deliveries in informational postings; however, operators are only required to keep the last 120 days of deliverability data available to the public, significantly limiting any type of trend analysis. The best proxy that can be developed is to gather parish level gas production data from SONRIS. Using this proxy assumes segments only transport gas produced in their respective parish, which might not be the case for every segment, but gives a general idea of which pipelines might be underutilized. Monthly parish production data was collected from SONRIS from 1977-2016. Individual years were summed and then percent decline was calculated from the difference between gas production during the peak year and 2016.

4.3.5 Cost Calculations

The final set of candidate pipe segments were the ones utilized for cost modeling purposes. The final set of candidate repurposing/conversion segments were incorporated into

the NETL cost model in order to estimate the avoided cost of converting the identified segments to CO_2 transport service.

4.4 Results

4.4.1 Geographical Screen

The repurpose candidate screening process started with 5,112 pipe segments that was reduced to 509 ideally located segments using a 10 mile buffer. These candidate segments are comprised of 39 operators which collectively span an aerial coverage over 3,234 geographic miles (Figure 16). Once integral and nonsensical segments were removed, the potential list of ideal candidates is reduced to 73 segments spread among 23 operators collectively spanning over 753 miles.

4.4.2 Capacity Screen

Most pipelines approved for construction during 2009-2017 were found to operate at 1,440 psi or less[6], a significantly lower pressure than what is recommended to transport supercritical CO_2. There weas also no significant relationships between MAOP vs OD, based on linear regression, (β_1=5.62, t-stat=1.15, p=0.2552, R^2=0.033). Without any significant relationship, descriptive statistics (average MAOP) were used for a given OD when using the Ideal Gas Law (Table 5).

When the NETL model was adjusted to account for the lower MAOP (1,200 to 1,400), the cost for constructing pipelines increases substantially. Specifically, larger volume (5 MMt) project 30 year OPEX increased by $30 million because additional compressors would be needed over

[6] Not all FERC applications contained information about MAOP, only about half of applicants report their MAOP.

longer distances (100 miles), or CAPEX increased $3 million because larger diameter pipes would be needed for shorter distances (10 miles). Smaller volume (0.5 MMt) project costs were similar for both long and short distances.

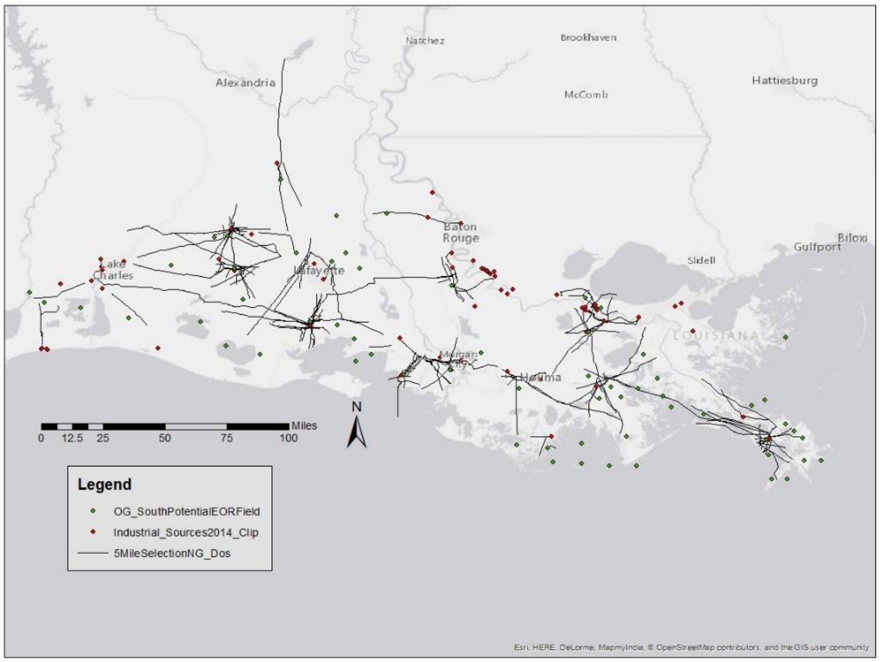


Figure 16. 509 potential natural gas pipelines within 5 miles of both a source and sink.

Table 5. Descriptive Statistics: Average MAOP (psi) from pipelines completed during 2009-2017. Data obtained through the FERC Completed Pipelines Database.

Outside Diameter (in)	Average MAOP (psi)	Standard Deviation (psi)	Number of Records
6	750	-	1
8	1,200	-	1
12	750	-	1
16	1,291	312	5
20	920	448	4
24	1,054	380	7
26	1,054	-	1
30	1,434	159	5
36	1,170	167	6
42	1,231	274	8

The list of 73 potential pipe segments was narrowed further after collecting daily natural gas capacity for individual operators from informational postings. Segments were most commonly removed from the candidate list because intrastate pipelines are not required to report capacity and thus no information was available. Additionally, some segments had apparently been sold at the time of this analysis and operator information had not been updated in MAPSearch (2017) or the NPMS (2017). It is important to note that the ultimate set of selected pipe segments is entirely a function of screening criteria, which itself is required due to limited data. More accurate data, therefore, will likely lead to differing results. The screening process estimates 31 possible segments for reconversion purpose. These candidate segment CO_2 capacities ranged from 2,700-41,000 t/day at 750 psi MAOP. Further, of the 31 selected candidate segments, only 16 segments have the ability to carry enough CO_2 in the gaseous phase to sustain an EOR project (Table 6). These 16 pipeline segments cover 203 miles and range in size from 6-30 inches and can collectively carry 359 Mt of CO_2 per day.

Table 6. Acceptable pipeline CO_2 capacity at 750 psi.

Pipeline ID	Diameter (in)	FERC MAOP (psi)	Gas Capacity (dth/day)	CO_2 Capacity at 750 psi (Mt/day)
MSP3046301-1	6	750	304,200	16.3
MSID406212	16	1,292	1,000,000	31.1
MSID406196	16	1,292	1,000,000	31.1
MSID406204	16	1,292	1,000,000	31.1
MSID406208	16	1,292	1,000,000	31.1
MSID406221	16	1,292	1,000,000	31.1
MSP3016308-1	20	920	300,000 (Mcf)	13.6
MSP3016325-2	14	920	300,000 (Mcf)	13.6
MSP3034331-1	12	750	303,000	16.2
MSP3034334-1	12	750	300,000	16
MSID1442456	22	920	285,000	12.4
MSID1442432	18	920	285,000	12.4
MSP3016939-1	30	1,434	642,000	18.0
MSP3038221-1	12	750	527,146	28.2
(Table con't)				

Pipeline ID	Diameter (in)	FERC MAOP (psi)	Gas Capacity (dth/day)	CO_2 Capacity at 750 psi (Mt/day)
MSP3038283-1	20	920	945,000	41.2
MSP3119589-1	26	1,054	430,000	16.4

4.4.3 Selection by Pipe Characteristics

The PHMSA annual reports indicate that most all companies who operate the candidate pipeline segments report that nearly all of their pipes are cathodically protected and coated. Further, the majority of these companies report that these pipe segments were constructed during the 1950-70s, except for portions of SONAT and Texas Gas Transmission infrastructure which both date back to at least the 1940s. However, any chosen pipe segment would need to be thoroughly inspected for wrinkle bends before conversion. Thus, no further reduction in the number of candidate pipe segments is required. General information regarding an operator's overall infrastructure can be found in Table 7.

Table 7. 2016 PHMSA Annual Report data presented by operator as percent of total infrastructure.

Operator	Pre 1950, unknown (percent)	Cathodic Protection and Coating (percent)	Carbon Steel (percent)
ANR Pipeline Company	0	100	100
Boardwalk Louisiana Midstream	0	100	100
Bridgeline Holdings L.P.	10.0	100	100
Columbia Gulf Transmission Comp	0	99.9	100
Florida Gas Transmission Company	0.4	100	100
Natural Gas Pipeline Company of America	0	100	100
Southern Natural Gas Company	12.2	100	100
Texas Eastern Transmission Corp	3.3	100	100
Texas Gas Transmission	32.1	100	100

4.4.4 Natural Gas Production Screen

Gas production for the 38 parishes of south Louisiana have all declined at least 58 percent since peak production. Only four parishes (Beauregard, St. Martin, Evangeline and Calcasieu) have seen declines less than 80 percent, while 32 have declined over 85 percent. All 16 candidate pipe segments are located within parishes which have declined at least 83 percent from peak production which means all segments are potentially being underutilized and no further reduction in candidate segments is required.

4.4.5 Cost Calculation

After summing the length of each OD and modeling the cost in the NETL model, the 203 miles of pipeline were found to cost $168.85 million in CAPEX to construct brand new. The cost per miles is about $830,000. The segment lengths and cost of each OD is presented in Table 8. See Figure 17 for final natural gas repurposing candidates.

Table 8. Capital costs to build new the 16 segments of pipeline identified as ideal candidates for repurposing. Costs developed using the NETL model.

OD (in)	Length (miles)	Cost to build new ($)
6	12.5	3,940,000
12	45.7	22,400,000
14	5.5	4,350,000
16	2.5	2,560,000
18	46	33,500,000
20	17.2	16,200,000
22	27.8	26,800,000
26	13.7	17,500,000
30	31.8	41,600,000
Total	202.7	168,850,000

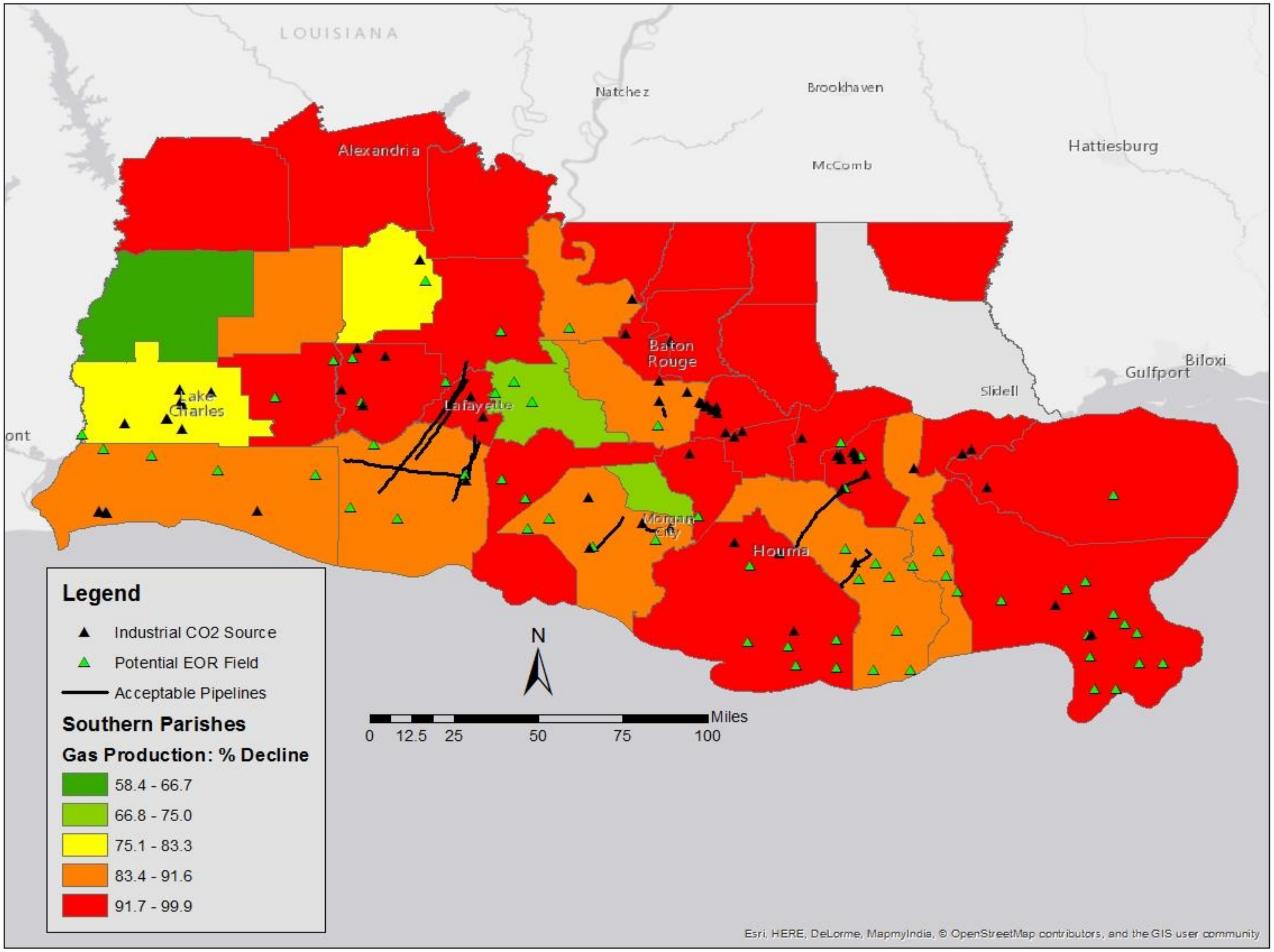


Figure 17. Natural gas pipelines identified as ideal candidates for repurposing to transport CO_2 and their location with respect to sources and sinks.

4.5 Empirical Results

4.5.1 Estimated Pipeline Conversion Capacities

The U.S. natural gas infrastructure, constructed during 2009-2017, is generally underrated for transporting CO_2 in the supercritical phase. Most pipelines completed during this time period were designed to operate at 1,440 psi or less, a level too low to transport supercritical CO_2. Most supercritical CO_2 pipelines are designed to operate at 2,200 psi and maintain at least 1,200 psi throughout the length of the pipeline. The compression variation between the suggested upper and lower limit of supercritical pressures is used to minimize the use of costly compression. This does not necessarily mean the current infrastructure must be ruled out since there are two repurposing options for the pipes either: 1) shorten the distance between compressor stations by increasing the number of compressors: or 2) increase the size of the pipe diameter. The latter of the two options is cheaper but requires a larger upfront cost. The current natural gas infrastructure is rated below what is commonly needed for supercritical CO_2; while this alone does not rule repurposing out, it would be expensive to operate the infrastructure at supercritical pressures.

There is a third potential option for candidate natural gas pipeline segments to be utilized at supercritical pressures without increasing costs. Recertifying pipelines to operate at an increased design factor would increase the overall MAOP (Kuprewicz, 2006). Currently, the design factor for most pipelines is set at 72 percent of SMYS but Kuprewicz (2006) argues certain pipeline design factors can be increased to 80 percent. An 8 percent increase translates to a new MAOP around 1,600 psi. Modeling the costs of CO_2 pipelines associated with operating pressures between 1,200-1,600 psi showed the costs are similar as if operating at 2,200 psi. While 1,600

psi is still well below the recommended pressure for supercritical CO_2 transport, it would alleviate the need for additional compressors in the environment and distances needed in south Louisiana.

Another repurposing option, as noted earlier, is to transport CO_2 in the gaseous phase. About half of the ideally located pipelines have enough capacity, even at lower MAOP (750 psi), to sustain EOR projects in a gaseous phase.[7] Brownsort et al. (2016) found that while transporting in the gaseous phase is less economic than transporting in the supercritical phase, it can be more economical than building a new pipeline to accommodate higher pressures. This is especially important when considering which oil and gas operators may be able to participate in the market. Currently, only large companies have the financial balance sheet to build transportation infrastructure able to support the growing EOR field. But if smaller companies are able to make an economic profit by repurposing natural gas pipelines, then the scope of the CO_2 transportation market expands considerably.

While the methodology presented here for calculating capacity is a rough approximation, it is assumed to be a conservative estimate for several reasons. First, the 750 psi chosen as the MAOP for all pipelines in the Ideal Gas Law equation is the lowest operating pressure found for natural gas pipelines constructed during the last eight years. Secondly, the use of reported informational postings used as the capacity proxy are only records of gas flowing passed the meter stations at receipt and delivery points. Meter stations represent the actual, or average, amount of natural gas entering or exiting during a reporting period leaving open the possibility

[7] An important aspect of transporting CO_2 in the gaseous phase is that it is unacceptable for EOR. EOR needs CO_2 in the supercritical phase. To make the project possible, compression would be needed at the site of injection. This aspect was ignored during the NETL model but is an important consideration if projects come to fruition.

of potential additional capacity. The only step in the process where there is the potential for inflated estimated capacity values is in assuming methane and CO_2 are ideal gases. A possible improvement to this method would be to use the van der Waals equation which includes correction factors to account for the differences in molecular structures of specific gases. However, the gas specific equation is cumbersome to utilize and has its own methodological issues, and is not necessary to generate first-order estimates.

4.5.2 Acceptable Pipeline Characteristics

PHMSA Annual Reports indicate that all of the pipelines selected in this study are likely constructed of steel with coatings and cathodic protection. On a larger scale, only 0.7 percent of Louisiana's transmission pipelines are cast/wrought iron or without corrosive protections. This finding makes sense given PHMSA's "Call to Action" to replace unprotected steel, cast and wrought iron pipes.[8] In fact, many states are in the process of completely removing cast and wrought iron distribution pipelines. The issue of pipeline age is also a concern especially for parts of the two pipeline systems that dominate south Louisiana: SONAT and Texas Gas Transmission. Older pipelines were subject to the relic pipe bending process which results in wrinkle bends. If any natural gas pipe segment is dated pre-1950, it must be inspected for wrinkle bends and if found should not be considered for repurposing.

4.5.3 Ideal Natural Gas Pipelines for Conversion to CO_2

It is important to remember 73 candidate pipelines are estimated to be ideally located near a source and sink but only 31 segments had enough information available to be used in the

[8] https://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp

Ideal Gas Law equation for capacity estimation purposes. Thus, there is likely considerable additional repurposing capacity potential in the 42 segments removed from consideration. About half of the 31 segments with complete information were estimated to have enough capacity to transport CO_2 volumes to sustain an EOR project. If these results are consistent across the board, then 21 additional segments, from the 42 candidate segments removed, might be added to the final list of 16 segments. If appropriate information is found to confirm this trend, then repurposing natural gas pipelines could be more broadly implemented.

Overall, the 16 pipelines identified in this study are expected to have a total capacity of 359 Mt CO_2 per day. There are 21 industrial sources within 10 miles of the ideal pipelines which together produced 10.7 MMt of CO_2 in 2014. The pipelines selected by the present methodology can carry all of the CO_2 produced by the 21 industrial sources and would only require 8 percent of capacity. However, when viewed on a per segment basis, most of the acceptable pipelines, while having the capacity to sustain an EOR project, will not be supplied with enough CO_2 from the nearby industrial sources or may be supplied with too much (Table 9). Of course additional supplies of CO_2 can be found from other industries and not all supplied CO_2 must be purchased, but, as presented by this study, most of the pipelines selected may not transport CO_2 in the most efficient manner.

4.5.4 Cost Comparisons

Two case studies were examined as a test on the capacity and cost estimates in this work. Denbury Resources and the No. 10 Feeder repurposing projects are estimated to have saved 88 percent and 68 percent on CAPEX, respectively. Given the modeled cost of building the 16 identified pipe segments in south Louisiana, companies could potentially save between $114 and

$148 million dollars on CAPEX by repurposing. Of course, there is large uncertainty in the potential savings given the small number of conversion projects and the limitations of modeled costs of building new pipelines. A range of estimates, therefore, may be more appropriate than the use of a point estimate for the capacity and cost of repurposed pipelines.

Table 9. Percent of CO_2 capacity by segment from industrial sources within 10 miles of each segment.

Pipeline ID	CO_2 Capacity at 750 psi (t/day)	Sources within 10 miles	CO_2 Supply (t/day)	Percent of Capacity
MSP3046301-1	16,300	1	307	1.9
MSID406212	31,100	3	8,431	27.1
MSID406196	31,100	3	8,431	27.1
MSID406204	31,100	2	1,928	6.2
MSID406208	31,100	3	8,431	27.1
MSID406221	31,100	3	8,431	27.1
MSP3016308-1	13,600	3	166	1.2
MSP3016325-2	13,600	9	19,925	146.5
MSP3034331-1	16,200	8	17,419	107.5
MSP3034334-1	16,000	2	331	2.1
MSID1442456	12,400	2	39	0.3
MSID1442432	12,400	1	15	0.1
MSP3016939-1	18,000	1	307	1.7
MSP3038221-1	28,200	3	218	0.8
MSP3038283-1	41,200	1	389	0.9
MSP3119589-1	16,400	2	331	2.0

4.5.5 General Conclusions

This study found a general lack of information specifying segment MAOP, year installed, material and capacity. Pipeline design specifications are important information, not just for deciding which pipelines can be repurposed, but for land managers, emergency response personnel and energy industry analysts. As was found during this analysis, pipelines are being bought and sold every year. In 2014 Bridgeline Holdings L.P. had been sold to Enlink Midstream and Chevron Pipe Line Company which included some 1,400 miles of pipeline. Adequate history

records might not be transferred leaving operators without an exact idea of the design specifications of their infrastructure. Inferring information about MAOP based on OD or capacity was not found possible using linear regression techniques. The lack of a significant relationship between OD and MAOP may be attributed to the large number of options available for pipe material in combination with using differing numbers of compressors. For example, U.S. Steel Tubular Products offer pipes with an OD from 1.9-24 inches, with each OD having a range of wall thicknesses and each thickness having nine different possible grades.[9] U.S. Steel offers 20 inch pipe which can range in MAOP from 640-2,900 psi. As a result, it seems almost impossible to determine the exact MAOP of a specific pipe without having the operator specific information. The reporting of which may be required in the future by the PHMSA in rulemaking Docket No. 2014-0092.

Given the constraints of the methods, only 1.4 percent of the 5,112 pipeline segments in south Louisiana are co-located near both a sink, a source and are likely repurposing candidates. The candidate conversion segments with information suggests only about half are able to carry enough CO_2 to sustain a typical EOR project. The 16 pipe segments identified in this study represent less than one percent of Louisiana's total natural gas infrastructure. A result that may strike some observers familiar with south Louisiana's extensive infrastructure by surprise. The results suggest the methods employed here are conservative and, if extended elsewhere, may find equally few candidate opportunities particularly from other states with less fossil fuel production history and infrastructure than Louisiana. While Denbury Resources was able to repurpose a pipeline in Mississippi, a state with some but very limited crude oil production, it

[9] https://usstubular.com/connections/sl/

could be an unusual case. Although this study identified possible options to be repurposed, there are still many hurdles to overcome before conversions can happen. The current natural gas pipeline owner would have to be interested in selling as was the case for Denbury Resources. An inline inspection would have to be passed indicating the pipeline does not have any malformations, such was a sticking point for the Tennessee Gas Company. Permits at several levels of government would have to be approved indicating the sale of the pipeline would not interfere on anyone's right to purchase natural gas and there were no undue consequences for the environment. The stars would have to align in order to make repurposing natural gas lines a feasible mitigation measure on a larger scale. This research corroborates the findings in Onyebuchi et al. (2017) that suggested repurposing pipelines may only be useful during the time period it takes for new CO_2 pipelines to be constructed.

CHAPTER 5: LOCALIZED BOTTOMS-UP PIPELINE CONVERSIONS

5.1 Introduction

The prior section of this research present the methods and results of what can be considered a “tops-down” approach of screening and identifying candidate natural gas pipelines for repurposing to CO_2 transportation. The approach identified earlier used a number of systematic equations and assumptions to generate capacity and cost estimates for CO_2 pipeline repurposing opportunities. However, this approach, like any modeling approach, is dependent upon assumptions and data availability in order to screen a very large number of regional natural gas pipelines for CO_2 repurposing. As noted earlier, about half of the candidate pipeline segments identified in the analysis were missing information and were not part of the final capacity and cost estimation process.

This section of the research employs an alternative “bottoms-up” approach at identifying candidate natural gas pipeline segments for CO_2 transport repurposing. This bottoms-up approach will encompass a smaller study area, a few select sources and sinks, and a relaxed selection process. The main goal of which is to provide a more detailed, and an expanded set of results than the prior utilized model. The results from this bottoms-up analysis can be compared to the results of the prior model to ascertain limitations and potential biases in the prior discussed methodology.

5.2 Bottoms-Up Methods

The bottoms-up method uses a combination of data for CO_2 industrial sources (US EPA, 2017) and potential EOR fields (SONRIS, 2017) with natural gas pipeline infrastructure MAPSearch (2017) to determine the number of repurposing opportunities available within a focused study

area. Instead of broadly looking across all possible sources and sinks, only a few select EOR fields and industrial sources were considered. The number of repurposing opportunities were broken down into several spatial scales. First, the available pipelines were systematically narrowed by removing pipelines which are nonsensical in that they did not provide a route between source and sink. This method considered pipe segments that provide an indirect route between sources and sink if connected to a series of segments outside the designated buffer. Second, once a final list of candidate pipelines had been selected, general characteristics about the pipelines were gathered from PHMSA reports. The analysis was carried out using ESRI (2017) ArcMap.

Two potential EOR fields, Bayou Sorrel (1200) and Paradis (7207), were used to narrow the focus of this study. Both fields had been previously identified as being well suited for EOR operations (Advanced Resources International, 2006; John et al. 2012) and are the focus of a recently commissioned study funded by the U.S. Department of Energy that attempts to develop a pre-feasibility finding on south Louisiana CCS. Bayou Sorrel is located in Iberville Parish and was discovered in 1954. Oil production peaked in 1999 at 11 bcf and has since declined to 152,000 Mcf in 2016. Paradis, located in Saint Charles Parish, was discovered in 1954, reporting peak production in 1977 at 2.8 bcf and has since declined to 193,000 Mcf in 2016.[10] Eight sources of industrial emission sources were chosen due to co-location near the EOR fields and relatively pure streams of CO_2 emissions (Dismukes et al., 2017). The select industrial sources ranged in emissions of 62,000-7,980,000 tonnes CO_2-eq in 2015 and represent a mix of natural gas refining

[10] Estimates of specific field peak production may not be accurate because electronic records are only available starting from 1977 but the state peaked as a whole in 1970 (Kaiser, 2010).

and hydrogen and ammonia production (US EPA, 2017). The next step in the process was to estimate the average distance between each EOR field and its three closest industrial sources.

Natural gas pipeline infrastructure was found using MAPSearch (2017) containing all commodity pipelines crossing Louisiana and then by extracting only natural gas pipelines. The three sources of data were then combined to get a graphical view of the pipeline infrastructure within the vicinity of the sources and sinks (Figure 18). Various sized buffers (1, 5, 10 miles) were used to define the extent of the natural gas infrastructure to determine the potential number of segments, mileage of pipe and number of different operators at various spatial scales. The segments within the 10 mile buffer were then used to systematically narrow the potentially acceptable natural gas pipelines by grouping segments by operator and visually checking if the select segment provided a route between source and sink. Whereas, the prior top-down method utilized a rigid approach that focuses on pipelines within the buffers of *both* source and sink, this bottoms-up approach focuses on pipelines in *either* buffer. This is an important distinction because the top-down method focused only on pipe segments which could act as a *direct* route; whereas, the present bottoms-up approach includes segments with *indirect* routes by connecting via a broader system of pipes outside of the buffer (see Figure A.3 as an example).

The PHMSA 2016 Annual Reports were used to gather general characteristics about the pipelines selected. Two annual reports are developed by PHMSA: one encompasses both gathering and transmission lines and a second which only includes distribution. The PHMSA chooses to separate the three systems because of differences in gas purity, pressure and end user. Annual reports are not geospatial in nature; instead, PHMSA presents the number of miles by operator and category. Categories include: decade installed; material; corrosive protections

(coatings, cathodic protections); and whether located onshore or offshore. While not spatially explicit to specific segments, the operator specific data results in a general idea of which pipelines might need to be more thoroughly inspected or completely dismissed. Like the top-down method, this bottoms-up approach selects segments built after the 1950s, made of steel and with corrosive protections in place. Data will be displayed as percent of total infrastructure by operator.

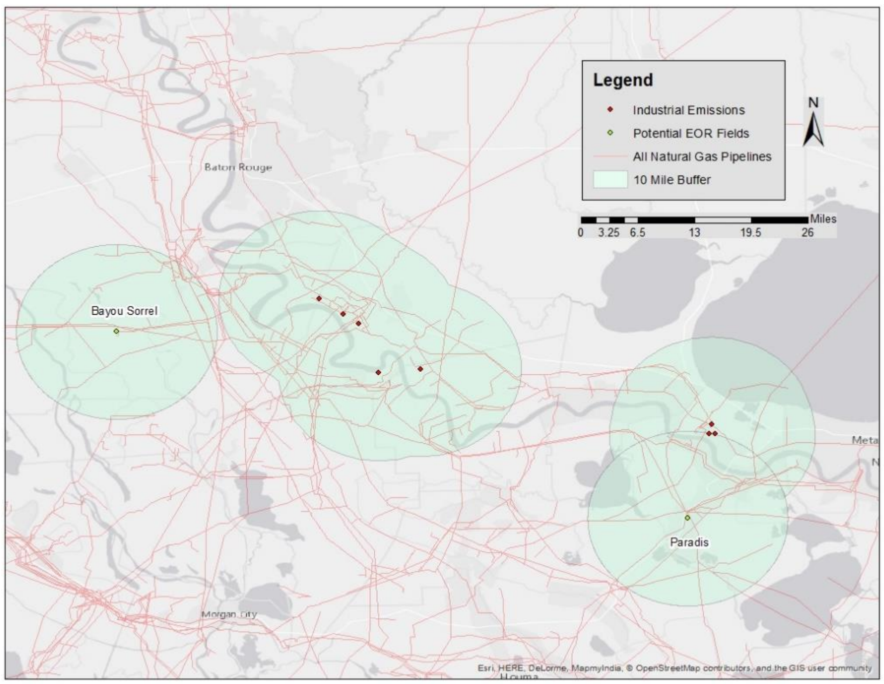


Figure 18. Industrial sources of CO_2, potential EOR fields and natural gas infrastructure.

5.3 Results

Paradis' and Bayou Sorrel's three closest sources of industrial CO_2 are on average 10.3 and 22.4 miles away, respectively. Available natural gas pipeline infrastructure within various sized buffers is presented in Figure 19.

The 10 mile buffer contains over 1,830 miles of potential natural gas pipelines, while the 1-mile buffer only contains 435 miles of natural gas pipelines. As the geographical scope becomes

smaller, obviously, fewer pipeline segments and less mileage are available. Complete details by individual buffer zone can be found in Table 10.

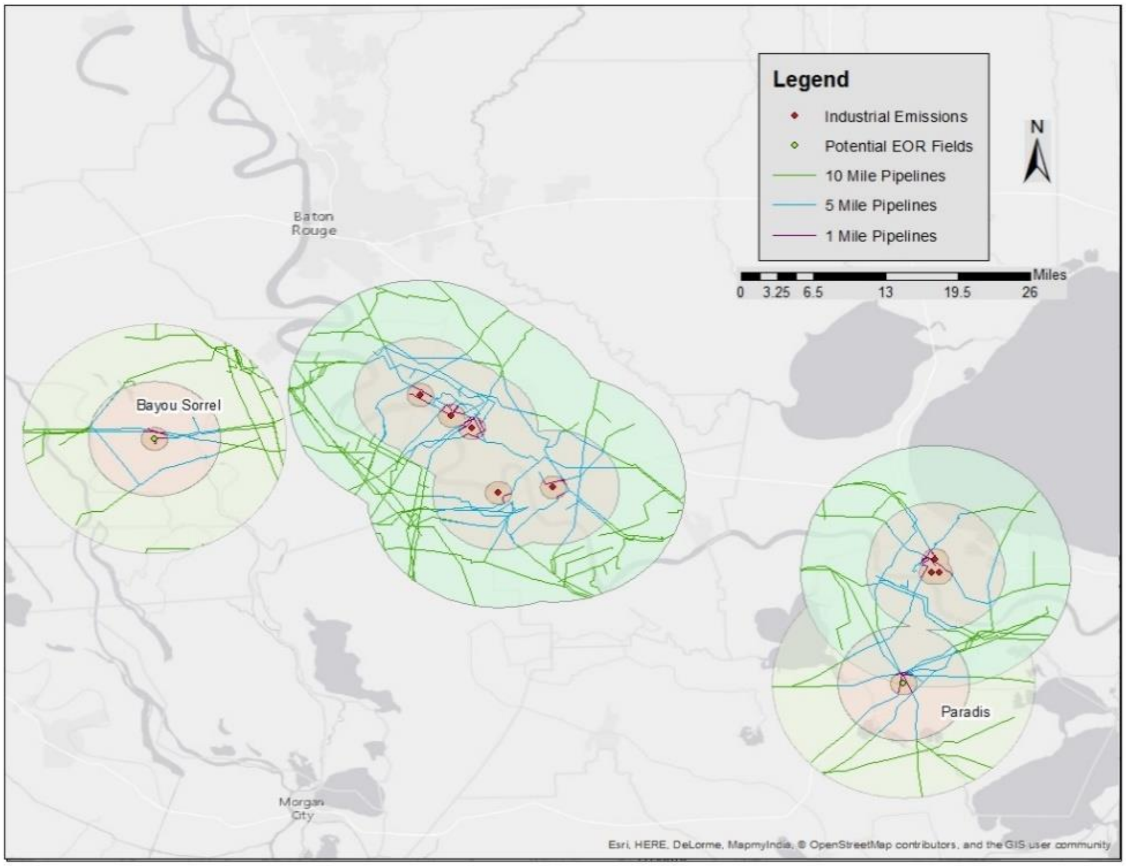


Figure 19. Available natural gas pipelines at various geographical scales (10, 5, and 1 mile zones).

Table 10. Available pipeline characteristics by Buffer Zone.

Buffer Zone	Number of Segments	Length (miles)	Diameter (in)	Number of Operators
1 Mile	74	435.8	2-36	12
5 Mile	179	1,048.2	2-36	15
10 Mile	359	1,830.1	2-42	19

There are 359 possible pipe segments located within 10 miles of a source or sink. After eliminating impractical segments, segments which do not provide a route between source and sink, the number of potentially acceptable pipe segments drops to 189 segments covering 1,020

miles. Many of the acceptable segments connect to pipes outside of the ten mile buffer and, while those segments outside are not included in the presented numbers, they would need to be purchased to repurpose the select pipelines (Figure 20). Acceptable segment characteristics by operator can be found in Table 11.

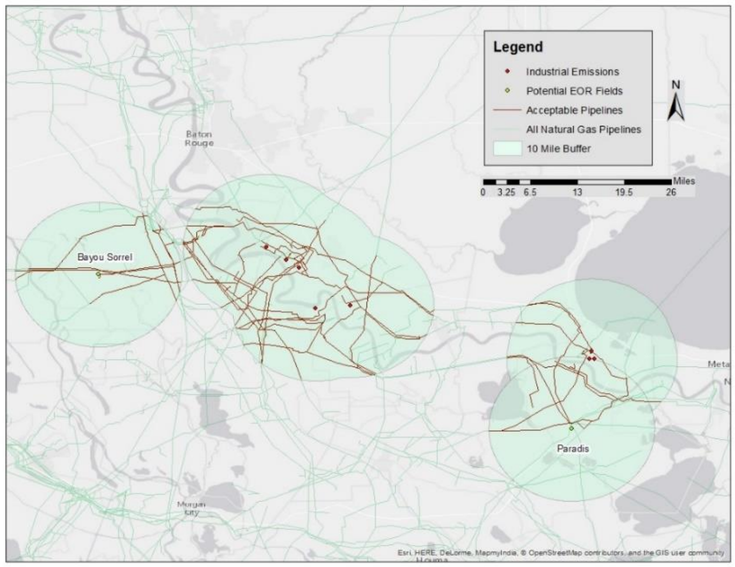


Figure 20. Acceptable pipelines within 10 miles of a source or sink. The selected pipelines do not run directly between sources and sink but rather are connected by a system of pipelines outside the 10 mile buffer highlighted by green lines.

Table 11. General characteristics of acceptable pipeline by operator.

Operator	Number of Segments	Mileage
Acadian Gas Pipeline System	28	131.6
Atmos Energy Louisiana Company	10	37.7
Cypress Gas Pipeline Company	21	108.7
Dow Pipeline Company	4	29.3
Enlink Midstream	49	339.7
Evangeline Gas Corporation	3	25.4
Florida Gas Transmission Company	8	35.5
Gulf South Pipeline Company	35	150.4
Shell Pipeline Company	2	18.4
Southern Natural Gas Company	11	39.0
Texas Eastern Transmission Corporation	5	31.3
Transcontinental Gas Pipeline Company	13	73.6
Total	189	1,020.6

Most of the segments selected are gathering or transmission lines and just a small proportion are distribution (retail). Annual PHMSA reports find over 97 percent of the gathering and transmission lines owned by the select operators have coatings and cathodic protections in place. Of the gathering and transmission lines, most pipelines fit the ideal characteristics to carry CO_2; however, over 30 percent of Cypress Gas Pipeline and Gulf South Pipeline Company pipelines were installed prior to 1950 or unknown dates. Atmos Energy Louisiana Company and Evangeline Gas Corporation are the only selected operators acting as local distribution companies (LDC). Distribution line data showed both Atmos Energy and Evangeline Gas have low amounts of corrosive protections, but this is mainly a result of having a large amount of plastic pipe included in the estimate. If plastic pipe is ignored, 100 percent of Evangeline's and 95 percent of Atmos Energy's steel pipe have corrosive protections in place. The main concern for the gathering systems selected is age: 100 percent of Evangeline's pipeline installation year is unknown. Table 12 provides complete details on these segments.

Table 12. Percent of mileage pre-1950s pipe and corrosive protection of acceptable pipelines by operator. Data obtained from 2016 Annual PHMSA Report.

Operator	Pre1950s, Unknown (percent)	Cathodic Protection and Coating (percent)	Carbon Steel (percent)
Gathering and Transmission			
Acadian Gas Pipeline System	1.09	99.9	100
Atmos Energy Louisiana Company	0	97.6	100
Cypress Gas Pipeline Company	39.3	100	100
Dow Pipeline Company	0	100	100
Enlink Midstream	13.6	100	100
Florida Gas Transmission Company	0.4	100	100
(Table con't)			

Operator	Pre1950s, Unknown (percent)	Cathodic Protection and Coating (percent)	Carbon Steel (percent)
Gathering and Transmission			
Gulf South Pipeline Company	32.4	98.9	99.7
Shell Pipeline Company	0	100	100
Southern Natural Gas Company	12.2	100	100
Texas Eastern Transmission Corporation	3.3	100	100
Transcontinental Gas Pipeline Company	5.8	99.9	100
Distribution			
Atmos Energy Louisiana Company	0.6	61.5	64.1
Evangeline Gas Corporation	100	33.7	33.7

5.4 Discussion

The bottoms-up methodology found a significantly greater number of potential natural gas pipelines to consider for repurposing. In addition to the relaxed selection process, more pipelines were found acceptable because the differing method focuses on a very narrow segment-by-segment analysis. This type of method, however, cannot be expanded to the entire dataset given the time constraints of examining each segment individually relative to an equally large number of sources.

The bottoms-up approach is also complicated by the distances between source and sink. Bayou Sorrel and Paradis' closest CO_2 sources are over 20 and 10 miles, respectively. Paradis' location is more similar to the design study presented in the tops-down analysis, whereas, Bayou Sorrel is located twice as far. The CAPEX modeled by the NETL to build a direct pipeline with an annual capacity of 4.38 MMt from Bayou Sorrel or Paradis to their closest source would be $14.3

million and $8.6 million, respectively. Based on previously converted pipelines, Bayou Sorrel and Paradis could save $9.7-$12.5 million and $5.8-$7.5 million, respectively. Longer distances mean more segment length would need to be purchased to connect Bayou Sorrel to its closest sinks. It stands to reason, repurposing pipelines in the vicinity of Paradis is more likely because less pipeline is needed to be purchased which is both cheaper and less likely to disrupt natural gas operations. The distance between source and sink is an important aspect operators need to consider for a successful CO_2 conversion project.

A caveat must also be made when using a relaxed, bottoms-up methodology for the pipeline selection process. Many of the segments identified as acceptable for repurposing require additional segments outside of the buffer to be useful. By choosing to include pipelines without a direct route from source to sink, the length of pipe required for repurposing increases. Natural gas operators may be unwilling to remove such a large portion of their overall system thus making the selected indirect pipelines less desirable. One solution would be to piece together several smaller segments from different operators and then, if needed, construct new pipe to connect the pieces. However, piecing individual segments together will be further complicated by having to deal with multiple operators. Ultimately, whether buying one large section of pipeline from one individual operator or piecing together small sections from multiple operators, the methodology employed here can be less advantageous than considering only segments with direct routes such as those found in the top-down analysis. Relaxing the selection methodology may provide more options to consider but at the cost of having to buy more segment length and complicating the process of transferring ownership.

The location of the select sources and sinks presents an interesting case study because, with the exception of CF Industries, both are located on opposite sides of the Mississippi River. The river has important implications on: 1) design specifications and 2) costs. As can be seen in Figure 20, pipelines located near the river generally do not take a direct path across; rather, the pipelines are built running along one side of the river until potentially more agreeable conditions permit a crossing (like existing ROW). Operators are also required to drill horizontally beneath the channel due to the sheer size of the Mississippi River (Greenwell, 2010). Both of these design implications will increase construction costs by adding additional pipe length, more technical construction processes and could potentially increase the time to permit. The difficulties of navigating major water bodies was evident by the Dakota Access Pipeline's crossing of the Missouri River which gained international attention, lengthened the construction period and proved more costly in the end (Worland, 2016). Pipe segments crossing major water bodies are conceivably more valuable than segments across land meaning natural gas operators may be unwilling to part with these sections. Future studies should incorporate sources and sinks located without any major water crossings.

Pipeline material, corrosive protections and age are important considerations for repurposing. Over 95 percent of the steel pipelines selected by this study have corrosion protections in place, an ideal attribute for CO_2 transport. The main concern for materials stem from Atmos Energy and Evangeline Energy Company's significant amount of pipeline made of plastic since these companies are likely LDC whose chosen lines are likely used for distribution and need to be removed. Plastic pipe generally operates at <100 psi which would limit capacity for CO_2 transport and thus may be unable to sustain an EOR project. Plastic pipes are also a

symptom of a larger issue with distribution lines. Distribution lines are not ideal candidates for repurposing because their main function is to service communities which legally bind the operator to supplying natural gas. If purchased, mitigation measures would need to be put in place to ensure communities continue to receive natural gas. In the case of Denbury Resources, mitigation measures required building a new, smaller pipeline to continue service. Lastly, the time period segments were built also plays a factor in whether the pipe can be repurposed. Over 30 percent of both Cypress Gas Pipeline and Gulf South Pipeline Company's infrastructure were installed prior to 1950 or unknown dates. Pipelines built prior to the 1950s were subject to bending practices which are known to create wrinkle bends diminishing the strength of the steel and increasing the likelihood for incidents. The PHMSA also suggests pipelines without adequate history records, such as unknown installation date, should not be considered for repurposing (PHMSA Docket No. 2014-0040). While older or unknown pipelines may still be acceptable if closely inspected or properly tested, the present methodology was designed to provide ample alternatives for consideration in cases where design problems exist.

While the rigid methodology, like the one presented in the tops-down analysis, is useful for survey studies, the outcome for repurposing pipelines to transport CO_2 is quite limited. The present methodology was developed to provide additional options for repurposing and be more widely applicable to specific parties. By narrowing the scope of the study to just a few sources and sinks, a more relaxed selection process can be employed to include segments which provide an indirect route for CO_2 transport. However, relaxing the selection process resulted in more segments which could ultimately prove impractical after a more thorough inspection. This study also highlighted aspects about pipeline conversions not covered in the tops-down analysis.

Important findings related to avoiding major river crossings and excluding plastic and distribution lines became apparent which would hinder the conversion process. Relaxing the selection methodology provides more segments for a specific source or sink to consider, but each segment will need to be thoroughly inspected.

The primary finding gathered from both the tops-down and bottoms-up analyses is that no matter how the pipeline screening process is conducted the number of pipe segments for repurposing is limited. Repurposing natural gas infrastructure to carry CO_2 is likely a “niche” application only available in a few places and situations. The enthusiasm for repurposing natural gas pipelines needs to be considerably tempered.

CHAPTER 6: CONCLUSIONS

EOR represents an important opportunity to offset the cost of CCS. EOR provides CCS applications with additional revenue streams from which high startup CAPEX can be mitigated. Louisiana is uniquely-poised to take advantage of EOR due to an extensive fossil fuel production history and a larger than normal industrial sector able to supply high purity CO_2. One obstacle to the expansion of EOR within Louisiana is the currently limited and geographically constrained CO_2 pipeline infrastructure used to transport CO_2 from industrial sources to EOR sinks. Studies have shown CO_2-EOR operators will need to build 1,000 miles of pipeline every year until 2030 in order to keep up with the pace of EOR and the Gulf Coast is set to see some of the largest percent increases. Some have argued that repurposing natural gas lines may be an important means by which high pipeline development costs can be mitigated. The purpose of this study was to examine the issues related to CO_2 pipelines and the possible alternative development of repurposing the extensive natural gas infrastructure in south Louisiana.

The repurposing of natural gas pipelines to transport CO_2 makes sense because natural gas and CO_2 pipeline construction practices are mostly similar except for a few nuances. CO_2, however, is generally transported in the supercritical phase and thus require pipelines able to withstand higher pressures (>1,200 psi). Higher grade steel is needed to accommodate higher pressures and will cost more when compared to natural gas pipelines. The governing agencies overseeing natural gas and CO_2 pipeline construction practices also differ; as common carriers, natural gas pipelines are highly regulated by the FERC but, with the exception of adhering to PHMSA guidelines, CO_2 pipeline construction is largely left up to individual states.

The costs of building CO_2 pipelines and how those costs vary with the volumes and distances expected for south Louisiana EOR are important. CO_2 pipelines may be able to take advantage of economies of scale; while total cost increases as project size increases, cost per unit transported will decrease. The higher pressures required for supercritical phase CO_2 transport require either additional compressors or larger diameter pipe; both of which increase total cost. Increasing the pipe diameter is the cheaper alternative over the life of the project, but will require a larger upfront capital cost. Ultimately, building CO_2 pipelines are still expensive and, given the infancy of the projects, operators need to consider other options to cut costs.

Repurposing abandoned or underutilized natural gas pipelines to transport CO_2 is one solution to save on CAPEX. This research develops a comprehensive tops-down model to determine the feasibility of implementing large scale pipeline conversion projects. The model's results revealed several development challenges. First, there is a general lack of public information and data on natural gas pipelines. The PHMSA is the only government agency collecting pipeline data on a nationwide basis; however, this information is limited to location, OD, commodity and operator. Pipeline data provided by PHMSA is also only accessible to the public one county at a time and the data are nontransferable. The author suggests PHMSA move forward with their plans to start collecting pertinent information on MAOP, year installed and material. This information is a resource not just for repurposing pipelines but is critical information for emergency response personnel, industry analysts and land managers.

While the literature suggests the most economical way to transport CO_2 is in the supercritical phase, this study found pipelines built during the last eight years operate at significantly less pressure than what is commonly recommended. While this alone does not

preclude pipelines operating at 1,400 psi from transporting CO_2 in the supercritical phase, the CAPEX or OPEX are higher compared to the suggested ideal pressures (2,200 psi) due to the need for larger diameter pipes or more compressor stations. On the other hand, this study has shown repurposing pipelines to transport CO_2 in the gaseous phase is still a viable option. By developing proxies for MAOP and pipeline capacity, we have shown gaseous transport can still support EOR operations. One drawback of gaseous transport is the lower pressure limits the potential number of pipelines from being acceptable for repurposing by reducing capacities which are then unable to sustain an EOR project. But if CO_2 pipeline conversions are to be a viable option, gaseous transport may be the only option moving forward. If the state of Louisiana is to take advantage of repurposing natural gas infrastructure, it would more than likely do so in the gaseous phase.

Lastly, while the rigid methodology developed in the tops-down method can be applied anywhere, it may only yield successful results in the few states with historical fossil fuel production similar to Louisiana. A bottoms-up approach was also developed to focus on just a few select sources and sinks, using a more flexible methodology to include pipelines which provide an indirect route between source and sink. More pipe segments were found acceptable for repurposing with the relaxed methodology but at the cost of overestimating the potential number of options and having more pipelines to sort through. Nonetheless, whether using a rigid or relaxed methodology for selecting pipelines for conversion, the outlook for successfully implementing pipeline conversion projects looks limited.

Repurposing natural gas infrastructure has been touted as an economical way to encourage EOR and mitigate climate change (Metz et al., 2005; Oosterkamp and Ramsen, 2008; Seevam et al., 2010; Rabindran et al., 2011; Noothout et al., 2014; Brownsort et al., 2016;

Onyebuchi et al., 2017). However, the findings presented in this thesis which encompassed various scales of south Louisiana found few options for repurposing. This was a surprising find considering the vast infrastructure in place in Louisiana; the few success stories in other parts of the world are probably something of an anomaly. Repurposing pipelines to transport CO_2 will likely be a niche application. While repurposing should still be encouraged as an option due to multiple indirect benefits, pipeline conversions more than likely will not be a significant climate change mitigation tool.

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APPENDIX: SUPPLEMENTAL DATA

Table A.1. Inputs used for the NETL model and associated units.

Inputs	Value	Unit
Financial		
Capitalization (fequity)	0.5	Percent
Cost of Equity (minimum internal rate of return on equity or IRROEmin)	0.12	Percent
Cost of Debt (id)	0.045	Percent
Tax Rate (rtax)	0.38	Percent
Escalation Rate	0.03	Percent
Project Contingency Factor	0.15	Percent
Depreciation method (DB150 – 150 percent declining balance or SL - straight line)	DB150	
Recovery period for depreciation (15 or 20 years)	15	Years
Starting Calendar Year for Project	2011	
Duration of Construction in years	3	Years
Duration of Operation in years	30	Years
Other		
Capacity factor	0.8	Percent
Input Pressure	2200	psig
Outlet Pressure	1200	psig
Change in Elevation	49	ft
Indicate equations to use for capital cost of natural gas pipelines	McCoy	
Region of US or Canada	SW	

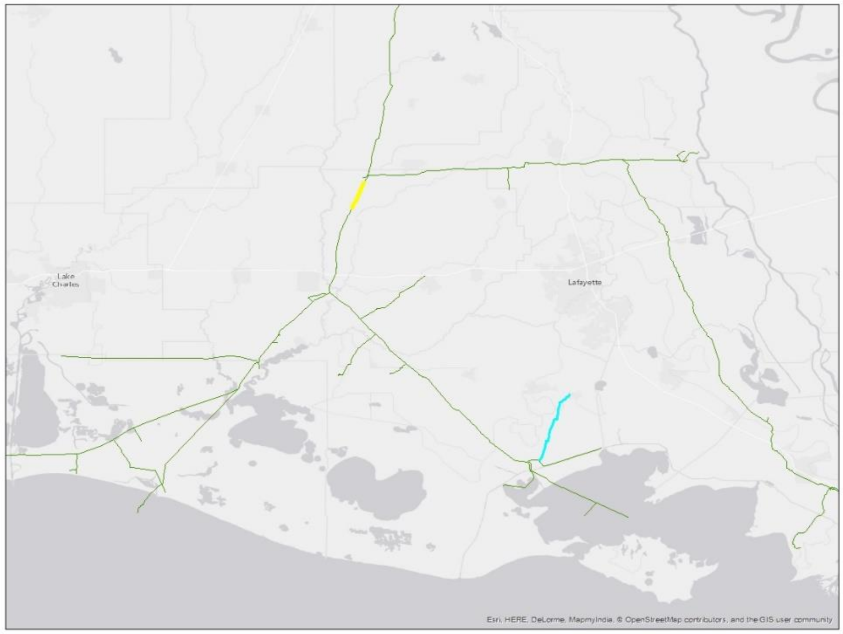

Figure A.1. Segments which are integral to an operator's overall system (yellow) were excluded from the analysis. This study included laterals of the ends of pipelines (blue).

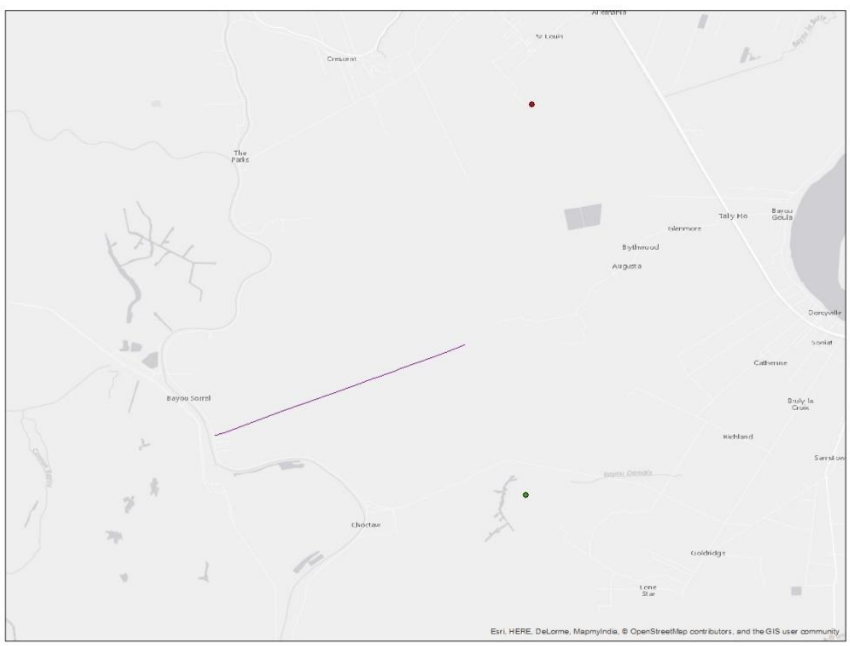

Figure A.2. Segments were excluded from the analysis if they did not provide a direct route from source to sink.

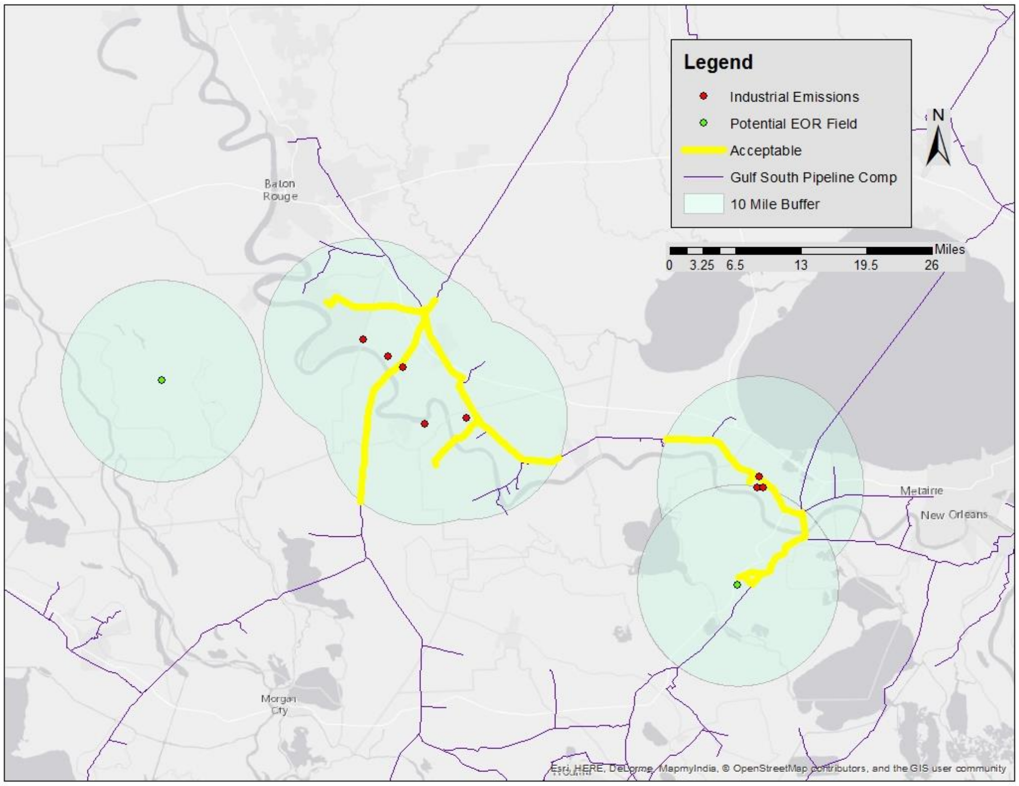

Figure A.3. Example of acceptable pipelines within the 10 mile buffer. Not all acceptable pipelines run directly to both a source or sink but are still deemed acceptable if connected by a system of pipes outside of the 10 mile buffer.

VITA

Michael Allen Layne III was born in San Diego, California. He has always held a deep appreciation and curiosity for nature. He considers himself fortunate to have been able to work in ecosystems from California, Idaho, New Hampshire, Sweden and Louisiana. Whether working in coastal dunes, mountains, deserts, swamps, marshes, fens, or arctic mires, Michael has always admired the beauty each has to offer even in the hot, cold, rainy or dangerous conditions he finds himself in. After graduation he hopes to find work to support travels to new places.