Carbon Capture and Storage
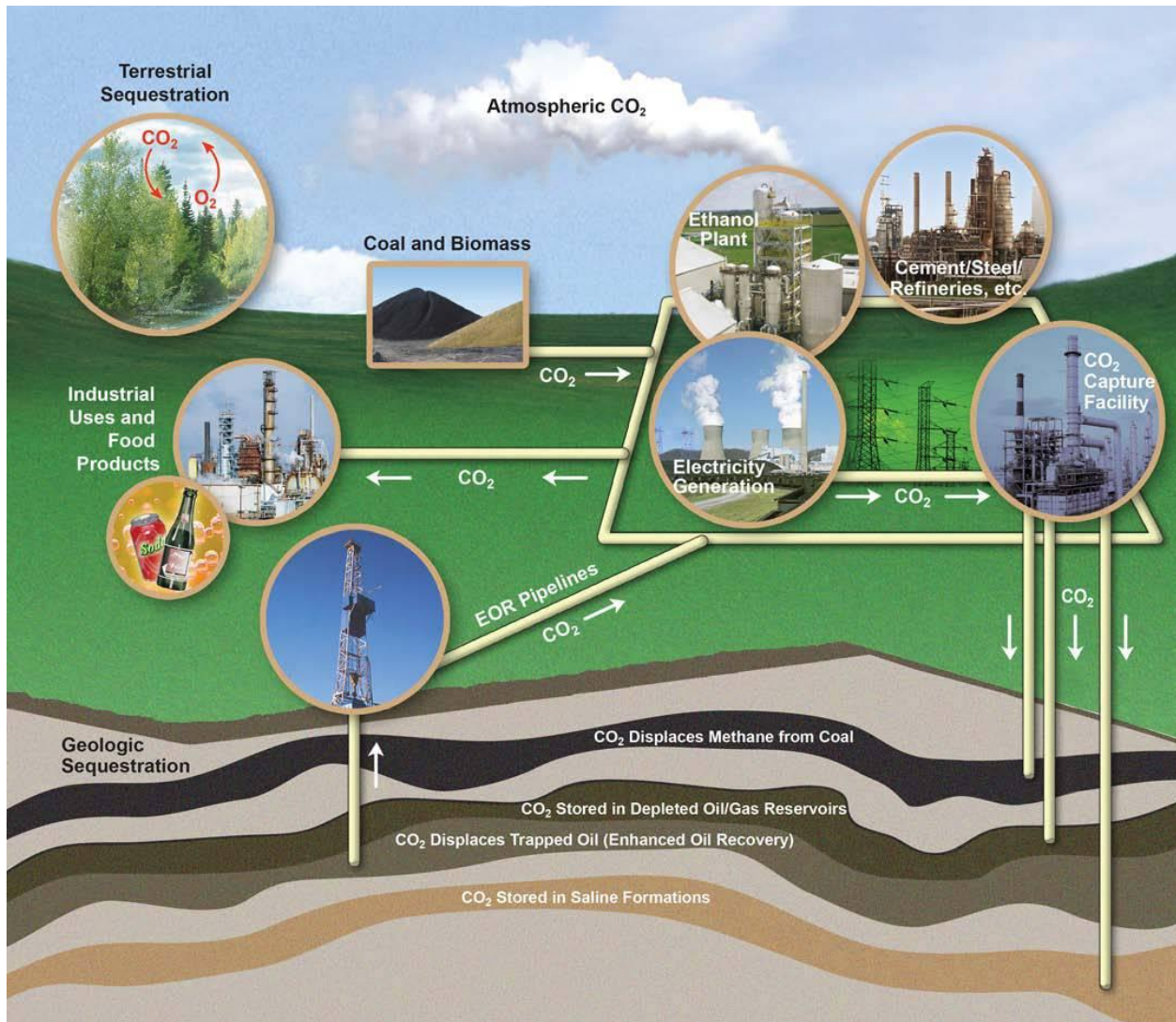

Figure 1: Anthropogenic Carbon Cycle [1.1]

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Executive Summary

This report examines the implementation of retrofitting and sequestration technologies on a 572MW coal plant in Shawville, PA for Carbon Capture and Storage (CCS) and Enhanced Oil Recovery (EOR) to make the project viable while reducing associated costs. This evaluation covers current government policies, capture technologies, transportation, sequestration within enhanced oil recovery, and monitoring environmental health and safety.

To mitigate the effects of climate change, carbon reduction strategies have been proposed to reduce anthropogenic emissions of green house gases due to fossil fuel use. Geologic sequestration of carbon dioxide (CO_2) may serve as a short-term solution to this long-term issue of increasing atmospheric CO_2 concentrations until alternative forms of energy beyond fossil fuels are proven economically feasible. The driver towards developing and implementing carbon sequestration strategies lies in new legislation in global and domestic policies. Carbon capture and storage (CCS) is poised as a potential mechanism to remove CO_2 before it is emitted into the atmosphere and transported through pipeline networks to a storage site. These transport networks are expensive and complex, and regional partnerships have been established to develop best management strategies for dealing with the long-term storage of CO_2. Geologic sequestration may represent the greatest strategy for the long-term storage of carbon dioxide because immense volumes of CO_2 can be stored in various underground formations. The costs associated with these technologies are extremely high, but there is an opportunity to reduce these costs through enhanced oil recovery via the underground injection of carbon dioxide into poorly producing oil and natural gas reservoirs. Carbon capture and storage strategies will only be effective in the mitigation of carbon dioxide emissions if they are cost-effective and pose little risk to environmental and human health. Various monitoring strategies have been proposed to assess the short and long term effectiveness of these projects and reduce associated risks.

Current policies and legislation highlight an increasing effort by both the federal and state governments to establish both an effective carbon cap-and-trade program and laws that provide bonus incentives in the form of carbon credits. Support from the government and related agencies are absolutely essential in order to make CCS projects economically feasible. Beyond understanding current policies, an analysis was performed for the most developed commercial scale carbon capture technology, MEA absorption, and compared with a new and promising technology, CAP. Through reviewed literature and software analysis, two processes were applied to the Shawville plant and it was determined that MEA absorption is the better, currently available technology on the basis of economics. The process shows an energy penalty of 11.7%, which brings the total thermal efficiency of the power plant down to 20.5%, and an avoided cost of $57.06 per ton of CO_2 captured. This study successfully characterized the carbon dioxide capture potential at the Shawville plant and further investigations of transportation and storage technologies revealed where this project can store its abated CO_2 emissions. Hydraulic parameters studied in Midwest Regional Carbon Storage Partnership region (MRCSP) show the Rose Run formation is a suitable storage site. In order to determine the best available injection site for this CCS project, the Ogden and CMU correlation economic models were compared. The annualized total capital costs of these two transportation scenarios yielded significantly different results. Pipeline length is the key parameter for associated transportation costs because of variations in construction and infrastructure

capital. Transportation costs can be minimized if CCS technologies are utilized within an enhanced oil recovery paradigm. Our ultimate storage site will be set up after implementation of geologic carbon sequestration within EOR. The potential of CO_2-EOR is globally significant and the United States is poised to benefit from its domestic application. CCS can also be done within EOR to mitigate the greenhouse gas effect of CO_2. This CCS project will only prove successful if we can reduce the associated implementation costs and ensure that geologic sequestration is done in a safe and sustainable manner. Ongoing site monitoring will be essential to understand the maturation of the injected reservoir and predict any sources of CO_2 leakage which may undermine the project and pose hazardous to environmental and human health. Carbon capture and storage can be made economically viable when carried out within EOR and through governmental support to subsidize the associated costs. After an evaluation of the available CCS technologies for retrofitting the Shawville power plant, this study concludes that carbon capture and storage is only economically feasible beyond the project's first ten years if project costs are further subsidized through additional government bonus incentives or profits from EOR by $46.87 per ton of CO_2 captured.

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1.1 Problem Statement

An assessment of the implementation of retrofitting and sequestration technologies on a 572MW coal plant in Shawville, PA for Carbon Capture and Storage (CCS) and Enhanced Oil Recovery (EOR) to make the project viable while reducing associated costs.

1.2 Overview

To mitigate the effects of climate change, carbon reduction strategies have been proposed to reduce anthropogenic emissions of green house gases due to fossil fuel use. Geologic sequestration of carbon dioxide (CO_2) may serve as a short-term solution to this long-term issue of increasing atmospheric CO_2 concentrations until alternative forms of energy beyond fossil fuels are proven economically feasible. The driver towards developing and implementing carbon sequestration strategies lies in new legislation in global and domestic policies. Carbon capture and storage (CCS) is poised as a potential mechanism to remove CO_2 before it is emitted into the atmosphere and transported through pipeline networks to a storage site. These transport networks are expensive and complex, and regional partnerships have been established to develop best management strategies for dealing with the long-term storage of CO_2. Geologic sequestration may represent the greatest strategy for the long-term storage of carbon dioxide because immense volumes of CO_2 can be stored in various underground formations. The costs associated with these technologies are extremely high, but there is an opportunity to reduce these costs through enhanced oil recovery via underground injection of carbon dioxide into poorly producing oil and natural gas reservoirs. Carbon capture and storage strategies will only be effective in the mitigation of carbon dioxide emissions if they are cost-effective and pose little risk to environmental and human health. Various monitoring strategies have been proposed to assess the short and long term effectiveness of these projects and reduce associated risks. Through this paper we will discuss the potential benefits, costs, associated risks and viability of retrofitting an existing power plant in Shawville, PA to progress CCS strategies beyond theory into real-world application.

Chapter 2: Policies and Regulations

2.1 Introduction [2.1] [2.2]

In today's globalized world, policies, regulations and laws are what drive changes significant enough to alter our society. With global warming as one of the most critical issue since the turn of the century, the United States, as the world leader, have been striving to come up with policies and regulations in order to reduce green house gas emissions. This had led to an increasing effort to propose new laws and acquire funding for Carbon capture and Storage (CCS) projects. Unfortunately, even with support from the private sector, CCS initiatives cannot be properly launched without the backings of the state and the government. In this section, key political factors that enable CCS to happen will be discussed and the pros and cons fully analyzed.

2.2 The Beginning of Regulations [2.13]

In 2007, the Supreme Court ruled that EPA must regulate greenhouse gas emissions, including CO_2. EPA initially claimed that it lacked authority under the Clean Air Act to regulate carbon dioxide and other greenhouse gases (GHGs) for climate change purposes. With the case decided at 5-4 in favor of regulating GHG, this was far from controversial and this sparked great interest in the nation that eventually becomes the start of house bills, discussion drafts and regulations in various states in the US.

Massachusetts v. Environmental Protection Agency

Supreme Court of the United States

Argued November 29, 2006
Decided April 2, 2007

Full case name	Massachusetts, et al., Petitioners v. Environmental Protection Agency, et al.
Docket nos.	05-1120
Citations	549 U.S. 497; 127 S. Ct. 1438
Prior history	On writ of certiorari to the United States Court of Appeals for the District of Columbia Circuit

Holding

Greenhouse gases are air pollutants, and the United States Environmental Protection Agency may regulate their emission

Figure 2: Massachusetts v. Environmental Protection Agency Supreme Court case

2.3 Stake Holders [2.1] [2.2] [2.3] [2.4] [2.9]

To better understand policies related to CCS, we must first be fully aware of all the stake holders. The following is a list of parties involved in CCS projects that must be considered:

1.) Energy Generation Sector

2.) State of Pennsylvania

3.) U.S. Environmental Protection Agency (EPA)

4.) Supreme Court and Obama Administration

5.)Residents of the USA (such as the farmer depicted below)

6.) Organizations supporting CCS
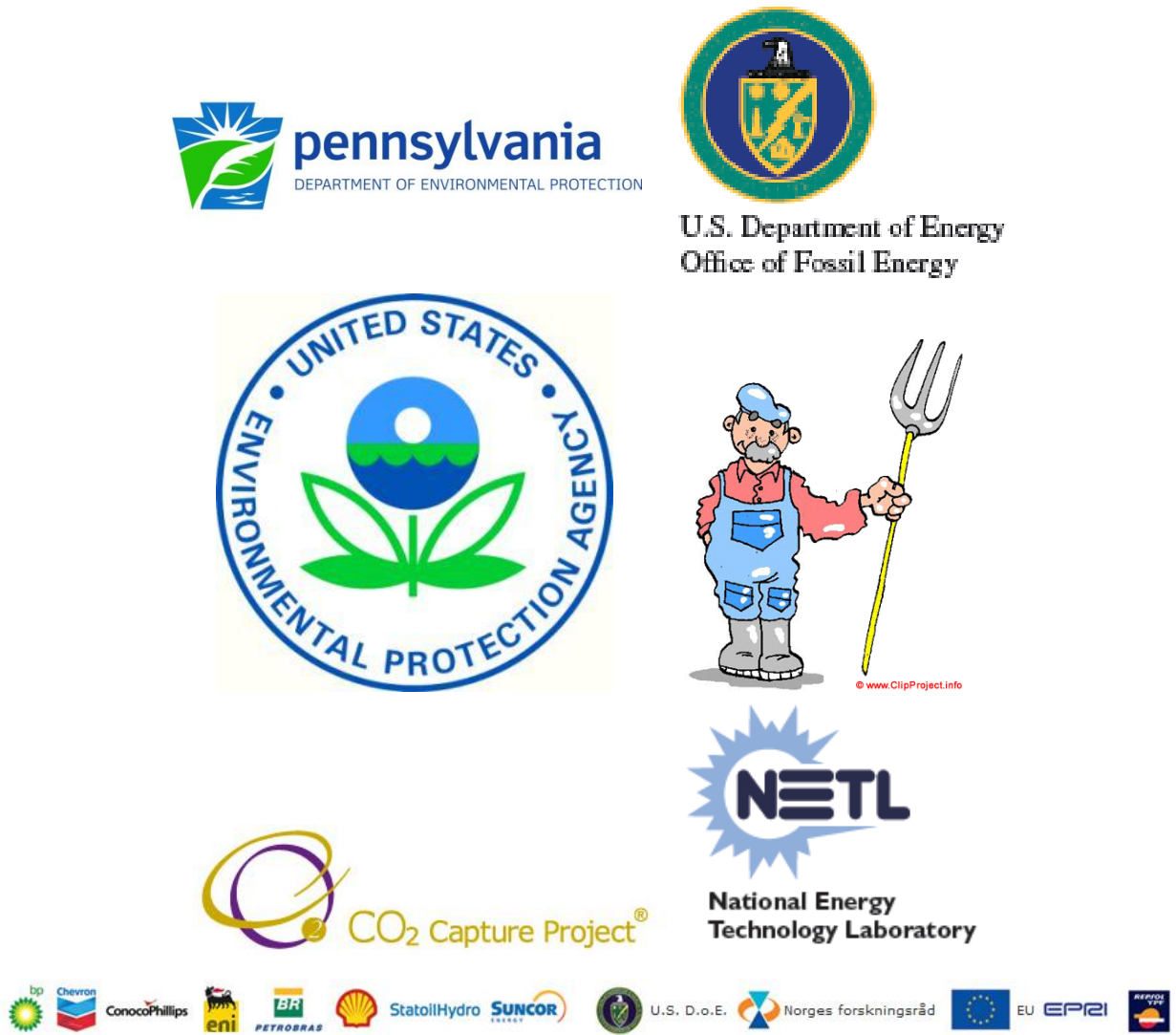
Figure 3: Logos and diagrams of CCS stake holders

In 2007, the Supreme Court ruled that EPA must regulate greenhouse gas emissions, including CO2. This has led to several initiatives from the EPA, some are listed below

- Clean Energy-Environment State Partnership

- Climate Leaders

- Combined Heat and Power (CHP) Partnership

- ENERGY STAR

The most relevant to CCS:

Tax Incentives to Reduce Greenhouse Gas Emissions

The following is taken from the EPA website:
http://www.epa.gov/climatechange/policy/neartermghgreduction.html

"The factsheet Energy Provisions of the American Recovery and Reinvestment Act of 2009 (ARRA or Recovery Act) provides information on the tax incentives for both individuals and businesses. The incentives are designed to spur the use of cleaner, renewable energy and more energy-efficient technologies that reduce greenhouse gas emissions. The tax incentives include: an increase in the energy tax credit for homeowners who make energy efficient improvements to their existing homes; credits to purchase for qualified residential alternative energy equipment, such as solar hot water heaters, geothermal heat pumps and wind turbines; and plug-in electric drive vehicles. The new law also includes increases to new clean renewable energy bonds and qualified energy conservation bonds. These are just a few of the energy provisions listed. The EPA web site contains more information on the Recovery Act, especially Clean Diesel."

2.4 The Cap-and-Trade Program [2.5] [2.6] [2.7] [2.10]

Cap and Trade, also known as Emissions trading is:

> *An administrative approach used to control pollution by providing economic incentives for achieving reductions in the emissions of pollutants.*

> *Government sets a national limit (**CAP**) for emission amounts then distributes to companies the rights (allowances) to emit gases (mainly CO_2). Companies are then free to buy and sell (**TRADE**) these allowances. Entities that emit more will have to pay more, thus providing them financial incentive to reduce emission.*
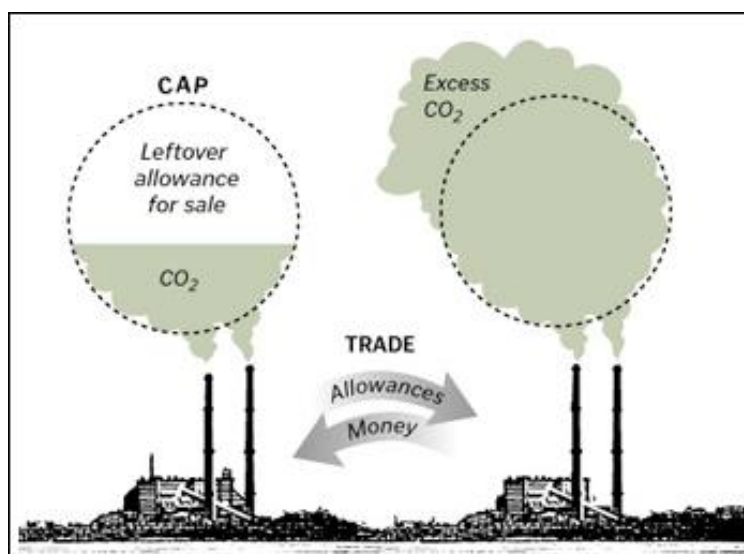
Figure 4: Cap-and-Trade Cycle

One of the two pieces of legislation currently being proposed in Congress is what is sometimes called "Cap and Trade". This Cap-and-Trade's House version is called the American Clean Energy and Security Act of 2009 and the Senate version, of the same bill, is the Clean Energy Jobs and American Power Act. The American Clean Energy and Security Act (H.R. 2454) , a cap-and-trade bill, was passed on June 26, 2009, in the House of Representatives by a vote of 219-212. The bill originated in the House Energy and Commerce Committee and was introduced by Rep. Henry A. Waxman and Rep. Edward J. Markey. This act also states the required GHG emission reduction target per year as follow:

Table 1: GHG emission reduction targets

Year	Required GHG Emission Reduction
2012	3.0%
2020	17.0%
2030	42.0%
2050	83.0%

As with all policies, there are benefits and drawbacks that must be considered and since the bills are viewable by the public the pros and cons as analyzed by policy makers and analysts can be summarized below:

Table 2: Pros and Cons for Legislation

Pros	Cons
Reduce CO_2 emissions	Higher electricity bills
Viewed as "greener"	Higher gas prices
Cleaner Air and Environment	Little impact on climate change
Create jobs	Damage to economy
	India/China might not follow through

Some have also questioned the motive of cap-and-trade policies as merely money making tools for the government as well. There is the theory that coal-fired power plant needs to feed a certain amount of coal to keep the turbine/generator complex spinning at 3,600RPM and that means the CO_2 emissions at this level is unavoidable. The argument is that by placing a cap on emissions that are lower than this 'minimum operational limit' will simply result in either the plant shutting down or the plant paying the

fees for going over the limit, and it ends up as a money-making scheme for the government. Inevitably, the energy companies will not absorb all that cost and will pass on the costs to the consumer, resulting in a significantly increase energy bill.

In addition, Pennsylvania was reported by the American Legislative Exchange Council as one of the top five states that would be most negatively affected by cap-and-trade. This stems from the fact that the agricultural industry still dominates Pennsylvania, and since farmers are already struggling with low produce prices the rise in fuel/gas prices used to power their equipment would be a huge setback. This leads to an increase in agricultural product prices, lessens the purchasing capabilities of consumers, forcing them to save more money and thus reducing the economy's aggregate demand. With the fall in consumer demands, manufacturers will cut back on production and reduce the needs for electricity. This goes back in full circle since with the fall in energy demand, less coal is needed which will drastically affect the PA coal industry.

But why is CCS such a key project in Pennsylvania?

This is because the largest single source of GHG in PA is from coal burning power utilities. In the year 2000, this sector produced 116.2 MMt CO_2 (equivalent), which is 37% of the state's emission

Figure 5: Coal-fired Power Plant in Pennsylvania

2.5 Worries on Geologic Sequestration [2.1] [2.2]

Geologic sequestration brings about new legal/regulatory issues in Pennsylvania. In a state where land ownership is already complex enough, debate rages on whether the land beneath the surface is owned by the land owner or the state. Then there is the transportation pipelines that will need to connect the power plants to the sequestration sites. In addition, the underground injection must be well planned; regulated and long term storage must be considered. Finally, the risk of underground water contamination and protection of natural resources must be taken into account.

2.6 Climate Change Action Plan [2.3] [2.11]

The figure below (figure 6) includes states where Climate Change Action Plan is initiated, and Pennsylvania is seen to contribute 1% of the world's CO_2 emission and 4% of the USA's.
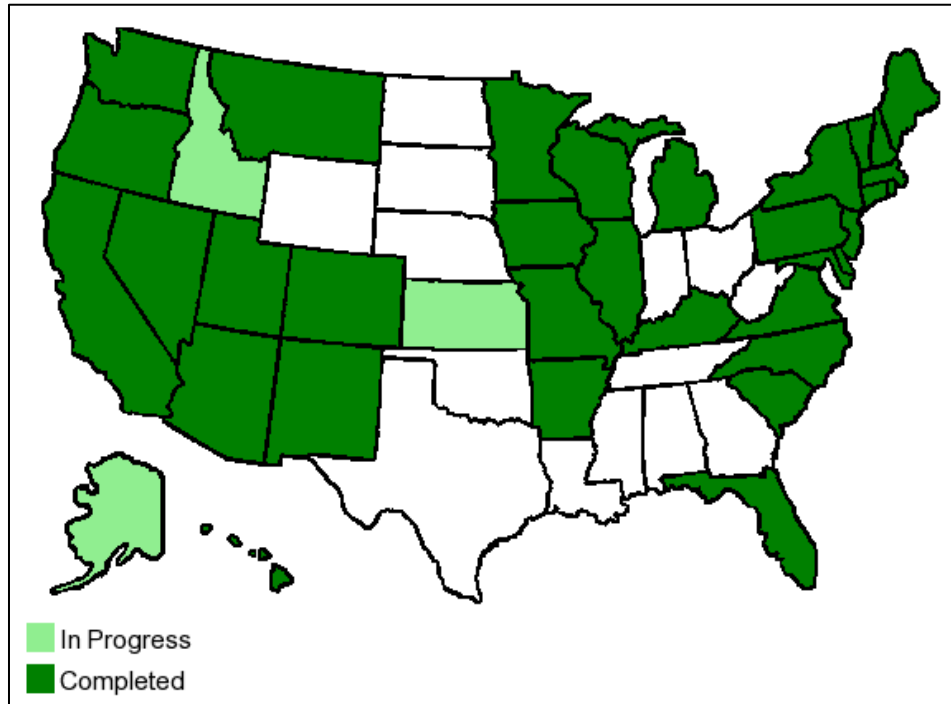
Figure 6: U.S. Map of states with climate change action plan or initiative

On July 9, 2008, Governor Rendell signed the Pennsylvania Climate Change Act (Act 70). On October 15, 2008, Governor Rendell signed into law House Bill 2200, which requires the Department of Conservation and Natural Resources (DCNR) to conduct studies of carbon capture and sequestration, and present its findings to the Governor and the General Assembly by mid-to-late 2009.

Figure 7: Pennsylvania State Capitol building

This results in Pennsylvania pushing hard to realize their Climate Change Action Plan, a comprehensive plan to '*reduce greenhouse emissions by as low as 30 percent of year 2000's level* if all the 52 recommendations are heeded.

The studies under House Bill 2200 will include:

(1) Identification of suitable geological formations for the location of a CO_2 sequestration network (due May 1, 2009)

(2) An independent assessment (due November 1, 2009) of the following:

- Costs to establish, operate, and maintain CO sequestration network.

- Safety and potential risk to individuals, property, and the environment associated with the geological sequestration of CO_2.

- Existing federal and state regulatory standards for the storage of CO_2.

- Factors contained in the U.S. EPA's vulnerability evaluation framework for geologic sequestration of CO_2.

- Different types of insurance, bonds, other instruments and recommended levels of insurance which should be carried by an operator of a state network during construction and operation, and availability of commercial insurance.

- Models for the establishment of a commonwealth fund to provide protection against risk.
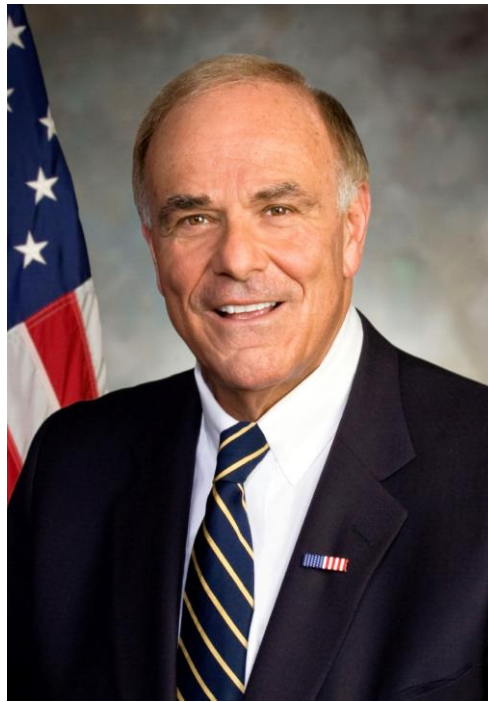
Figure 8: Governor Edward G. Rendell
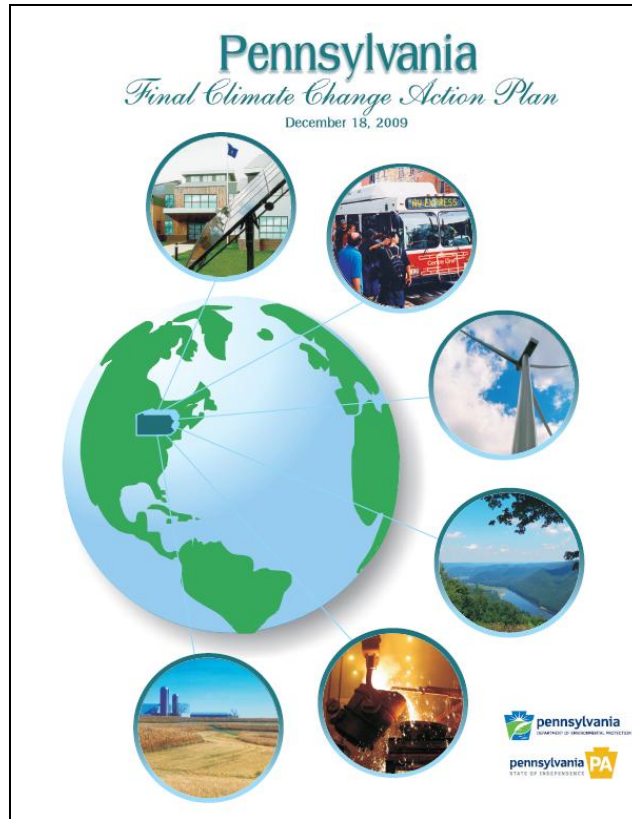
The Climate Change Action Plan contains 52 recommendations to mitigate GHGs. The following is part of the CCS plan as stated in the Climate Change Action Plan:

Carbon Capture and Sequestration in 2014
The work plan entails carbon capture retrofit to existing supercritical pulverized coal plants starting in 2015 through 2019. In addition, the work plan calls for installation of an integrated coal gasification combined-cycle (IGCC) plant in the state in 2020. Retrofits of existing supercritical pulverized coal plants entail amine scrubbing with a CO_2 capture rate of 90% and an increase in heat rate (a decrease in efficiency). The reduction in efficiency results because the amine-scrubbing system diverts steam for power generation or consumes additional power for CO_2 compression. IGCC power plants use coal to produce electricity. The technology is based around a gasifier that produces a mixture of hydrogen and carbon monoxide called syngas. This syngas is burned in a gas turbine that is used to drive a generator. IGCC technologies with CO_2 capture are equipped with three more processes than the conventional IGCC technology without capture. The first is a process of reacting syngas with steam to produce CO_2 and hydrogen through shift reactors. The second process separates the CO_2 from the remaining gas. The final process compresses and dries the CO_2. Adding CO_2 capture technology to IGCC plants significantly reduces overall plant efficiency. Twenty of the 21 CCAC members approved and 1 member disapproved of recommending this work plan to DEP for including it in Pennsylvania's Climate Action Plan.

The above section describes the plan for CCS in the year 2014 and mentions of the use of amine-scrubbing system; this will be analyzed in the next chapter.

House Bill 80

HB 80 is currently under consideration and will involve CO_2 indemnification funds, providing sequestration and transport pipeline facilities amongst others. The Climate Change Action Plan states on this bill: Implementation of the Carbon Capture and Sequestration (CCS) would be supported via passage of House Bill 80. DEP and DCNR are working collectively with a varied group of stakeholders, and the Clinton Foundation, to hasten the commercial deployment of CCS in PA.

This bill has been under review for a considerable amount of time and has come under heavy criticism for the wording used in the bill.

1.) The wording on the bill suggests that in the event a viable sequestration network is not, or cannot be developed, coal-fired power plants that have already installed carbon capture technology would still receive credits for CCS, even though it did not actually sequestrate the captured CO_2. This totally defeats the main purpose of the bill which is to reduce CO_2 emissions. It could even create a situation where new coal-fired plants are built with just capturing technology and no sequestration technology since it is not required in order to receive credits. The solution would be to make sure that a sequestration network is in place before coming up with any credit program.

2.) The state assuming liability for 1st sequestration site rather than energy generator. Since the liability for a CCS project is unknown because none have been performed commercially before, it is too risky for the state and PA taxpayers to assume liability.

2.7 Policy-related Commercial Terms [2.2] [2.4] [2.8] [2.12]

The main driving force behind a successful project is a successful negotiation with the commercial considerations. And what better way to give a project that extra kick when there are regulatory policies backing it? With such a backup, the owners of a power generation plant maybe better equipped to decide on how and when to retrofit their existing plant with CCS. This is because regulations like cap-and-trade or tax credits will empower the sector with funds for capital investments, bonus incentives and cost mitigations. This section will analyze a variety of opportunities for power plant owners to reduce their financial risks.

Storage and transport
20%

Capture CO_2
80%

▲ Operating costs associated with CO_2 capture represent over 80% of the total costs associated with the CO_2 capture, transportation and storage cycle.
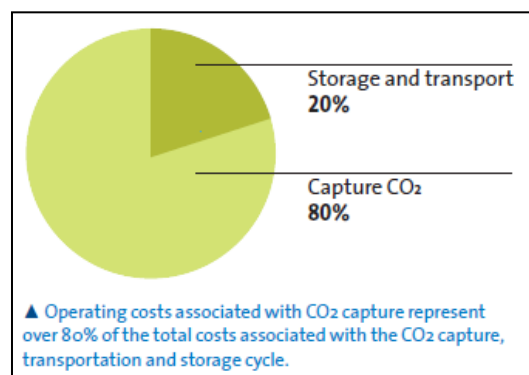
Figure 10: CO_2 Capture Project Brochure

Federal sequestration tax credit and investment tax credit for CO_2 pipelines:
-15% of costs incurred in EOR/EGR (IRS Form 8830)

- Renewable Electricity Production Credit (REPC), currently, the REPC for these technologies is 1.9 cents per kWh (CCSReg Interim Report)

-$16 per ton of avoided CO_2 for a federal production tax credit including avoided SO_2, NO_x and mercury emissions (CCSReg Interim Report)

Dingell-Boucher – discussion draft:
This latest cap-and-trade program regulates coal downstream, right where the source of emissions is. CCS projects are also responsible for any leakages occurring from the project. The equation goes like this: $90 per ton for early projects, eventually dropping to $50 per ton (Available for the first 10 yrs of operation)

$$\frac{(Tonnes\ of\ CO_2\ emmisions\ avioded)(bonus\ alloeance\ value)}{Average\ value\ of\ an\ emission\ allowance\ during\ the\ preceding\ year} \tag{1}$$

This discussion draft was chosen as the policy backing this project due to the favorable support it gives CCS projects and because it was proposed by two very respectable people: U.S. Representative John Dingell (D-Michigan), chairman of the U.S. House of Representatives Energy and Commerce Committee (E&C) and Rep. Rick Boucher (R-Virginia), chairman of the Energy and Air Quality subcommittee of E&C. The draft has also been widely-reviewed by many organizations, including NRDC, Lots of Environmental Groups, Rep. Edward J. Markey (D-Mass.), Chairman of the Select Committee on Energy Independence and Global Warming and a senior member of the House Energy and Commerce Committee, Wilderness Society, and Greenpeace. Even though the reviews were mixed, most appreciates that this bill is the foundation of future drafts or versions that will eventually govern CCS in the future.

Considerations for Utilization of CO_2

There are considerations to be taken when categorizing CO_2 as "waste" or "merchandise". In an EOR/EGR project this is clearly categorized as "merchandise" and state and federal laws are being proposed that will determine tax policies regulating uses for CO_2 in cases like this. The price of CO_2 then becomes a big factor and the market for CO2 will need to be analyzed.

2.8 The future of CCS [2.9]
Amidst all the pros and cons, house bills and discussion drafts, numerous stake holders and renewed government funding, the big question to ask is "Is there a future for CCS?"

In September 2009, a demonstration projects in West Virginia by American Electric Power proved that CCS is a technological success. However, this does not prove that CCS will become a commercial success or even feasible in other parts of the country. This is because CCS requires a sequestration site that is determined by availability of geologic formation that is suitable for storage. Unfortunately, such a site is not always available within a reasonable distance from coal-fired power plants. Extended pipelines could be used to alleviate this problem but, as will be discussed in the transportation section, this comes at a huge cost.

Carbon capture and storage is also directly competing with other alternative energy resources such as wind and solar. If solar technology/commercial-ability reaches a level where it can compensate for coal-fired sources, then coal-usage would decrease, reducing the need for CCS projects in the first place.

According to PennEnvironment, Greenpeace and the European Renewable Energy Council have also released a report in March, 2010 that the US can cut GHG emissions by 85% by 2050 without having to rely on CCS while doing it at half the cost and twice the job creation.

So is there a future for CCS? There is no definite answer for that, but one thing that is certain is that it cannot be done without supporting policies and regulations.
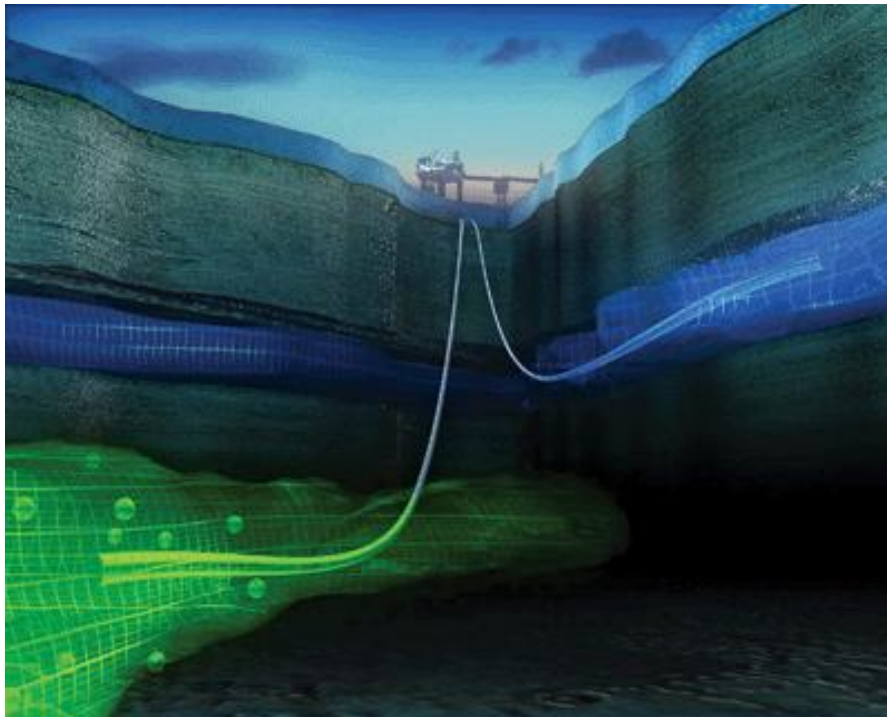
Figure 11: Computer-Generated cross section of a sequestration site (Energy Tribune)

Chapter 3: Retrofitting of an Existing Power Plant

3.1 Shawville Power Plant Specifications: [3.1]

The Shawville Generation Station is a pulverized coal (PC) power plant operated by Reliant Energy Mid-Atlantic PH LLC. It is located in Clearfield County, Pennsylvania on 947-acres along the Susquehanna River. There are four steam boilers, two front wall-fired units in operation since 1954 and two tangentially-fired twin furnace units in operation since 1959 and 1960, with a total generating capacity of 572 megawatts (MW).[3.1] Each boiler is equipped with low NO_x burner technology and has been in compliance with regulated emission standards since 1996. Cooling water is obtained from the Susquehanna River at a rate of 535 cubic feet per second, cooling the flue gas to an average exit

temperature of 149°C. Electrostatic precipitators have been utilized since 1976, and the plant still meets the particulate emission standards of 0.1 lb/mm Btu. Fly ash and bottom ash are land filled on-site.[3.1]

The plant consumes 1.4 million tons of Pennsylvania bituminous coal per year. This coal has a higher heating value (HHV) of 11,987 Btu/lb, an ash content of 13.86%, and a sulfur content of 1.78%. This equates to 33.9 trillion Btu/yr of input heat content. Comparing this to the 3.2 million MWh of net annual electrical generation provides a plant thermal efficiency factor of 32.2%, on a HHV basis. Average sulfur dioxide (SO_2) emissions are in the range of 2.73-2.81 lb/mm Btu, which meets the 3.7 lb/mm Btu EPA emission standard. Annual carbon dioxide (CO_2) emissions from the Shawville plant, as reported by the EPA in 2005, are 3.4 million tons.[3.1]

3.2 Carbon capture technologies: [3.2], [3.3]

There are three different approaches that can be utilized for the capture of CO_2 from coal power generation facilities: post combustion capture, pre-combustion capture, and oxy-combustion. Post combustion capture separates the CO_2 from the other constituents of the flue gases. A gasifier utilizing water-gas-shift is the pre-combustion capture pathway, while oxy-combustion uses an air separation unit to burn the coal in a concentrated oxygen stream in order to produce a concentrated stream of CO_2. Since pre-combustion capture technologies apply to gasifier units it will not be considered for application to the Shawville PC steam generation plant.

3.2.1 Post-combustion capture

Post-combustion capture is appropriate for retrofitting air fired coal power plants. The flue gas stream from air fired plants typically contains a concentration of CO_2 less than 15%.[3.2] This low concentration stream requires large equipment to handle the high flow rate of gas which emerges from the system. The flue gases emerge from the system at ambient pressure, requiring high performance or circulation to obtain high capture rates and significant pressure steps to meet transport and sequestration requirements. Options available for post-combustion CO_2 capture are discussed in detail below.

3.2.1.1 Amine-based absorbents

Chemical solvent scrubbing using monoethanolamine (MEA) is the currently favored technique for post-combustion CO_2 capture. Amine scrubbing has over 60 years of use in industry, with CO_2 capture rates being observed between 85 and 95 per cent with a product purity of over 99%. Before introduction to the solvent, the flue gas is cooled and particulates along with other impurities are removed. Degradation of the amine, along with corrosion of equipment, occurs from the reaction with SO_x, NO_2, and O_2. Typically the SO_x concentration needs to less than 10 ppm, while selective catalytic reduction is necessary to obtain the low levels of NO_2 in order to decrease the rate of degradation.[3.2]

After the flue gas is cleaned and cooled, it is passed through a packed column with the MEA traveling counter-current to the flow. The acidic CO_2 absorbs into the basic solvent and is passed from the bottom of the column to another column where it is heated with steam and the CO_2 is stripped from the solvent. After the CO_2 is removed it is compressed for transport and the solvent is returned back to the absorption column. This process requires large equipment to handle the large volumes of flue gas coming from a power plant.[3.2]

Alternative amine based solvents are being developed to reduce the regeneration energy requirements, degradation, corrosiveness, and equipment size while increasing the capacity and rate of CO_2 absorption. Hindered amines, blends of MEA with other amines, and amino acid salts are all being studied; however the capital and operating costs along with costs for the solvents are currently more expensive than MEA.[3.3]

3.2.1.2 Aqueous ammonia absorption [3.4], [3.5]

Alstom has been developing a chilled ammonia process (CAP) which operates in a similar manner to the amine systems described above. The absorber operates at temperatures less than 10°C, requiring the flue gases to be cooled via chilled water and direct cooling units. The chemical absorption occurs in a column between ammonium carbonate (AC), CO_2 and water to form ammonium bicarbonate (ABC) precipitates.[3.4] These precipitates are then passed through a high pressure pump and moved into a regeneration unit, which acts much like a distillation column. Heat is applied to dissolve the ABC to produce gaseous CO_2, ammonia (NH_3), and water (H_2O). A water wash column is used to condense out the NH_3 and H_2O, from the now high purity CO_2 stream (>99.9%), and reform ammonia carbonate for re-use. The CO_2 product stream leaves the process at 435 psi, and is then compressed to 1500 psi for transport and storage.[3.4]

A 90% capture rate has been observed in single stage demonstration scale plants. It is important to keep the process operating below 10°C to ensure minimal ammonia slip, which will react with SO_x and NO_x in the cooling units to form ammonium sulfate and ammonium nitrate.[3.4] These are fertilizers which could be a salable by-product; however they will require additional solvent operation and maintenance costs. Operating at this low temperature enables the formation of solid ABC, as opposed to aqueous ABC, and increases the CO_2 capacity of the solution. Also, the moisture present in the flue gas condenses out and reduces the volumetric gas flow rate, increasing the concentration of CO_2 and reducing the size of absorber columns.

Alstom reports lower steam consumption in comparison to the MEA process of only 15% with a higher solvent loading, resulting in a thermal efficiency penalty of only 3.5% compared to MEA's 11.6%.[3.5] Table 3 shows the energy performance effects of CO_2 capture using MEA and NH_3 absorption. Verification of these savings needs to be preformed, due to the higher power consumption involved in refrigeration and flue gas fanning.

	Supercritical PC Without CO$_2$ Removal	SCPC With MEA CO$_2$ Removal Parsons Study	SCPC With NH$_3$ CO$_2$ Removal Current Study
Coal Feed rate, lb/hr	333,542	333,542	333,542
Coal heating value, Btu/lb (HHV)	11,666	11,666	11,666
Boiler heat input, MMBtu	3,891	3,891	3,891
LP Steam extraction, lb/hr for reboiler	0	1,215,641	179,500
Steam Turbine Power, kWe	498,319	408,089	484,995
Generator loss, kWe	(7,211)	(5,835)	(7,018)
Gross plant, kWe	491,108	402,254	471,301
Plant Auxiliary Load (IDF, FGD, BFW pumps, Water pumps, Cooling Towers, CO2 unit, Chillers, CO2 compressor, BOP), kWe	(29,050)	(72,730)	(53,950)
Net Power Output	462,058	329,524	421,717
Net efficiency, % HHV	40.5	28.9	37.0
Avoided Cost, $/ton CO2	Base	51.1	19.7

3.2.1.3 Membranes

There are several types of membranes being studied for the recovery of CO$_2$ from flue gas. Physical or chemical interactions drive the separation of gases via membrane material, allowing specific components to pass through the membrane more easily than others.[3.2] The more promising technologies for retrofitting include gas absorption membranes and inorganic membranes. Additional development is required in order to make membranes cost effective for large scale power plant CO$_2$ capture.

Gas absorption membranes allow for alternative solvent use which would otherwise be ineffective in gas and liquid direct contactors (adsorption systems). The concept passes flue gas through membrane tubes, while an amine solution collects permeating CO$_2$ on the other side of the membrane.[3.3] Impurities would be blocked by the membrane, reducing loss of amine through degradation while possibly increasing its loading capabilities. In order for this technology to be viable, selectivity and permeability of the membrane needs to be increased while decreasing the cost.

Inorganic membranes have been able to selectively separate CO$_2$ from methane (CH$_4$), which is useful for purifying natural gas streams. A microporous silica membrane containing amine functional groups is being developed for the separation of CO$_2$ from flue gas streams.[3.2] It is hypothesized that the amine functional pores and permeating CO$_2$ interactions will enhance the selective diffusion of CO$_2$ while blocking the other flue gases present from transferring through the membrane. These are still in the

laboratory phase of development, where increased membrane selectivity and permeability are the main focus.

3.2.1.4 Solid adsorbents [3.6]

Solid sorbents which can remove CO_2 at relatively high temperatures are being proposed for flue gas capture. By requiring smaller or no cooling units for capture onto the sorbents, there is potential for reducing efficiency penalties compared with absorption processes. Solid sorbents can be regenerated by applying heat, effectively liberating high purity CO_2 from the surface. Jones et al. has done extensive research on numerous adsorbent materials.[3.6]   Figure 12 shows the ideal relationship between temperature and CO_2 loading for each of the adsorbents studied. It can be seen from the graph that zeolites, lithium zirconates, and amine impregnated structures along with organically-supported amines depict an acceptable range of capacity in relationship to temperature.
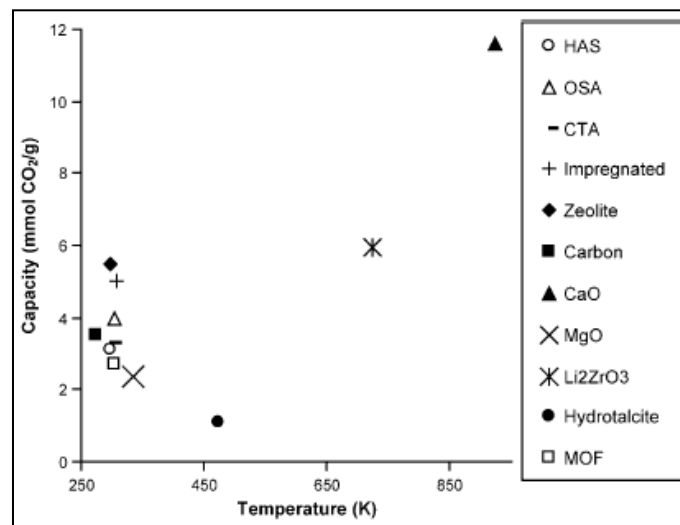
Figure 12: Highest reported CO_2 capacities of all solid adsorbent classes at different temperatures

Zeolites rank among the fastest known kinetic rates for CO_2 adsorption, enabling the material to load most of its capacity within seconds of being introduced to the stream. Ideal adsorption occurs at 0°C, and desorption of CO_2 from the surface occurs at temperatures higher than 120°C.[3.6] So, significant cooling and then reheating must occur in order for this structure to be utilized in power plants.

Lithium zirconates show high adsorption capacities of up to 4.5 mmol/g, high thermal stability at temperatures above 400°C, and regeneration characteristics better than other oxide absorbents.[3.6] However, even at high temperatures it takes several hours and even days to become loaded with CO_2. Additional research is required in order to increase the kinetic adsorption rate in order to overcome this limit.

Amine enhanced adsorbants show the most promise as a near term capture technology. A general tradeoff occurs with the loading capacity and kinetic rate of adsorption, where a lower amine content normally decreases the capacity and a higher content decreases the adsorption rate. Impurities in the

flue gases will have the same effect on amine bound to adsorbants as it does on amine absorbant systems.[3.6]

Overall, additional research is necessary to increase adsorbent performance for their practical application to post-combustion CO_2 capture. Increased loading capacity along with adsorption rates need to be realized to be competative with other technologies, in addition to studies to find the effects of typical flue gas constituents on reactivity and selectivity.

3.2.2 Oxy-combustion

Oxy-combustion is the burning of fuel in a pure oxygen stream, rather than in atmospheric air. Recirculation of the flue gases needs to occur in order to bring the flame temperature within the boilers down to normal air-blown temperatures. The main advantage of burning fuel in pure oxygen is that there is a lower flue gas volume which consists of concentrated CO_2 (about 80%).[3.2] Water can be condensed out of the flue gas stream, decreasing the volume and increasing the CO_2 concentration even more. This process is better suited for gas turbines, rather than coal combustion, since it contains fewer contaminants in the fuel stream.[3.3] For application to coal combustion power plants, the process requires extremely efficient contaminant gas removal in order to reach the high levels of purity obtained in post-combustion processes. The economic benefit of oxy-combustion is not evident for coal application, due to the large costs associated with air separation and flue gas recirculation on top of the purification technologies which also need to be implemented.[3.2]

3.3 Capture Technology Selection

Based on the literature review performed, the technology which appears to be best suited for CO_2 capture at the Shawville Generation Station is post-combustion capture utilizing the chilled ammonia process proposed by Alstom. However, the most developed and employed technology is the absorption method utilizing MEA. The CAP process, being in the pilot stage of development, lacks a supply of unbiased data. Following is a description of the analysis which was performed in order to select the more appropriate capture option between the two processes. For both of the processes it was assumed that a 90% capture rate would be accomplished with the equipment being operational at a 90% capacity factor. All costs are assumed to be in 2010 equivalent dollar amounts. Also, a levelized cost of power was assumed to be 6.5¢/kWh, and a capital charge factor of 0.175 was used [3.7].

3.3.1 Monoethanolamine Analysis

The first step into implementing an absorption system that operates with MEA is to build a flue gas desulfurization scrubber. Using an EPA fact sheet on scrubbers, capital cost and operations and maintenance costs of $100/kW and $22/kW, respectively, were used [3.8]. This amounts to a capital investment of $40.5 million and $8.9 million of annual operations and maintenance costs. The scrubber's power draw is assumed to be 1% of the total energy produced, which leaves the power plant with an output of 405.4 MW [3.8].

After the instillation of a scrubber occurs, the absorption and desorption units were evaluated. Information provided by the National Energy Technology Laboratory was used to determine the capital cost, operations and maintenance cost, and energy penalty associated with a MEA capture system.

Figure 13 below shows the relationships between the afore mentioned criteria and the amount of CO_2 captured. It can be seen that each shares a linear relationship to sizing conditions, and therefore a linear fit trend line is used to determine the Shawville site specific values. The capital cost of the MEA equipment at Shawville will cost $406 million, with operations and maintenance costs of $87.7 million. The equipment will incur a 10.7% energy penalty on the power plant, which will amount to a final power output of 258.1MW.
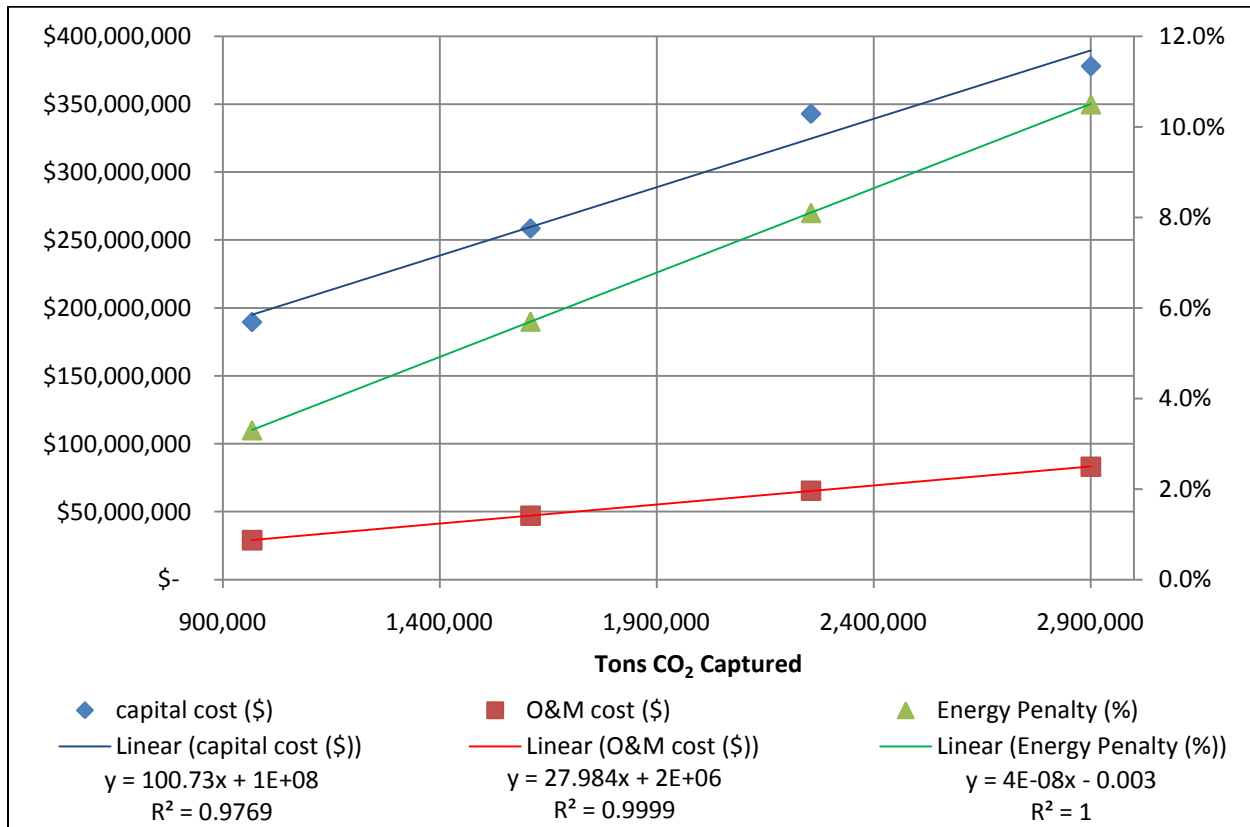
Figure 13: MEA Capture Cost and Energy Penalty Analysis

3.3.2 Chilled Ammonia Process Analysis

Due to the lack of detailed data for the chilled ammonia process available within literature, a model was drawn up in SuperPro Designer® and can be seen below in figure 14. Several assumptions were made in order to describe the model. First, a steady state analysis was performed using data from DOE/NETL and the flue gas composition was determined and can be seen in Table 4 below. These flue gases enter the direct contact water cooling tower at an average temperature of 149°C and exit at 23°C, and then they are chilled to 5°C. The gas stream is then passed through the absorber where it runs countercurrent to a 26%-wt ammonia solution. This solution contains the ammonia in the form of ammonium carbonate, and the reaction with carbon dioxide forms ammonium bicarbonate with an absorption of 0.10 kg CO_2/kg solution. The flue gases are then passed through a washing column to precipitate out any ammonia which may have escaped the system. Solid ABC is removed from the stock solution by hydrocyclone, and then pressurized to 435 psi and passed through a heat exchanger to obtain a temperature of 80°C. A reboiler produces steam for the stripper, which operates at 120°C, and

CO_2 is subsequently removed from the ABC to form AC once again. Another washing column is utilized to precipitate out any NH_3, and then the 99.9% purity CO_2 stream is sent to compression for transport.

Capital costs and operations and maintenance for this process, as determined by the software, are $65.1 million and $227.5 million, respectively. The equipment has a power load of 70 MW, which equates to a net energy penalty of 5.6%.

Table 4: Flue Gas Composition (w/out capture)

	mass flow rate		mass percentage
	kg/hr	ton/yr	
CO_2	392,132	3,403,902	15.1%
SO_x	5,413	46,976	0.2%
NO_x	793	6,885	0.0%
H_2O	222,000	2,176,548	9.7%
N_2	1,581,262	15,503,132	68.7%
O_2	144,105	1,412,847	6.3%
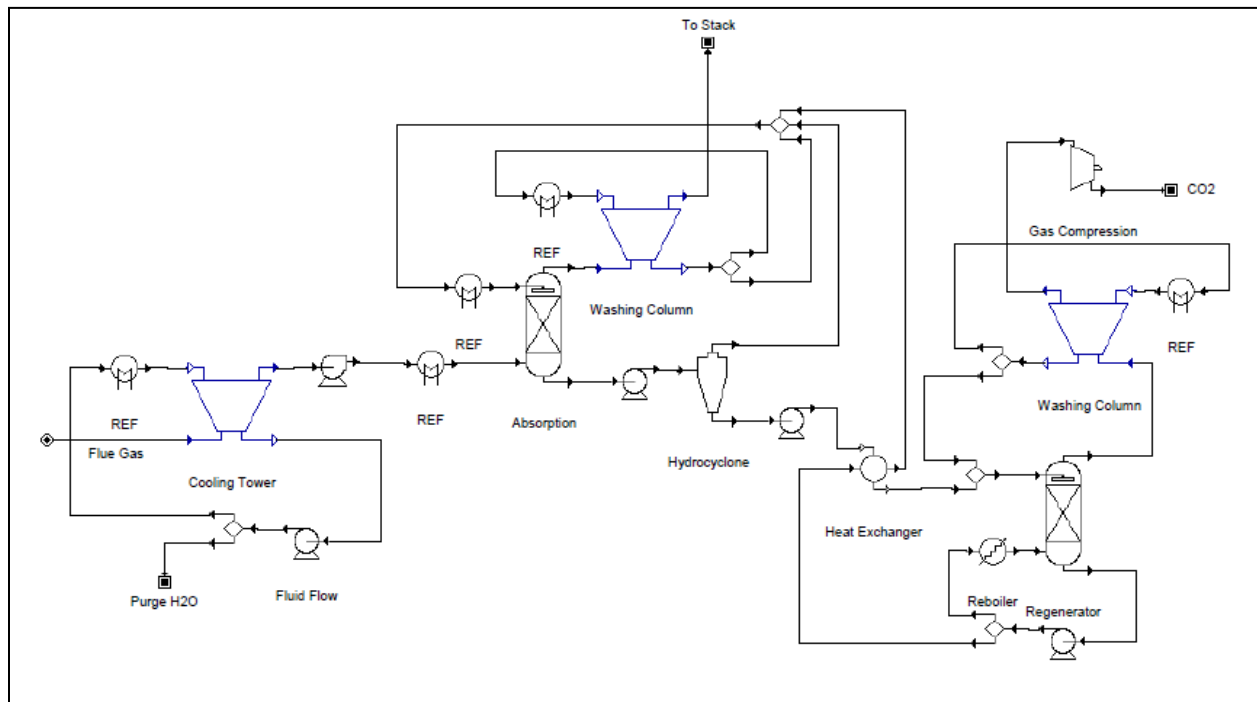
Figure 14: CAP flow diagram [SuperPro Designer®]

3.3.3 Summary and Comparison of Selected Technologies

After evaluation of the two most promising technologies for CO_2 capture, it is determined that a MEA system is the better option for application to the Shawville power plant. The MEA system, with flue gas desulfurization, incurs an 11.7% energy penalty compared to just 5.6% for the CAP system, which equates to a final power output of 258 MW and 335 MW for the respective technologies. Although this

analysis appears to show favor to the CAP absorber, the economics show favor to the MEA absorption system. The performance and cost analysis, applied to the Shawville power plant, can be seen in table 5 below. Due to the benefits seen for avoided cost per ton of CO_2 captured, the decision is to use MEA absorption for the analysis.

Table 5: Shawville Plant Performance with and without CO_2 Capture

	Base Plant	MEA w/ FGD	CAP
Energy Input (MW)	1259	1259	1259
Energy Output (MW)	405	258	335
Energy Penalty	-	11.7%	5.6%
η_{th} (% HHV)	32.2%	20.5%	26.6%
Capital Costs (MM $)	-	446.6	65.1
O & M Cost (MM $)	-	96.7	227.5
Avoided Cost, $/ton CO_2	-	57.06	77.97
Price (¢/kWh)	6.5	14.99	15.44
Price Increase		57.3%	58.5%

3.3.4 Future Capture Work

For future evaluations, modeling both processes would be beneficial in order to get a better comparison of stored energy values and costs within the software. Also, Alstom is currently in the process of gathering research from their pilot scale plant, which should be analyzed and used in subsequent reports [3.4]. More selective absorbents than MEA have been discussed in literature, but they too need to be tested at the commercial scale before a conclusion can be drawn [3.2]. As reports develop and become available, it is important to analyze them for any bias which may be present. The energy penalty values obtained from this report for CAP are consistent with those found in literature; however they do not coincide with avoided costs as presented by Alstom, the exclusive owner of marketing and sale of the patented process [3.5].

Chapter 4: Transportation and Storage with cost estimation

4.1 Introduction

Carbon capture and storage (CCS) requires CO_2 to be captured from energy production process, compressed to high pressures, transported to a storage site and injection into a suitable geologic formation. Each of these steps is capital and energy intensive and will have a significant impact on the cost of energy production and ultimate benefits/goal of CO_2 reductions..

Our CCS project is based on the coal fired power plant (Shawville, PA, 572MW capacity) which is located in the Midwest Regional Carbon Sequestration Partnership (MRCSP) region. This study focused on the general geologic storage potential in the MRCSP region and hydraulic parameters of formations. We determine that the Rose Run formation is the best candidate for the storage with a potential capacity between 244 million tons and 1025 million tons.

Because of different pipeline transportation scenarios, this study's objective was to maximize any related benefits and to compare the economic cost results of two storage sites. The first one is to inject CO_2 into the formation underlying the power plant with a radius of 25 miles and the second scenarios is for EOR purposes 250 miles away from the power plant.

4.2 Geological CO_2 Sequestration Opportunities in the MRCSP

4.2.1 A Snapshot of the MRCSP

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is a public/private consortium that is assessing the technical potential, economic viability, and public acceptability of carbon sequestration within its region. The MRCSP region consists of seven contiguous states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. A group of leading universities, state geological surveys, nongovernmental organizations and private companies listed below and led by Battelle, compose the MRCSP. It is one of seven such partnerships across the U.S. that makes up the U.S. DOE Regional Carbon Sequestration Partnership Program. [4.1]

• Population: 50.8 million (1 in 6 Americans)
• Gross Regional Product: $1,534 billion (1/6 U.S. economy)
• 21.5 % of all electricity generated in the U.S.
• 77 % of electricity generated in the Region is generated by coal.
• 12 % of nation's total CO_2 emissions.
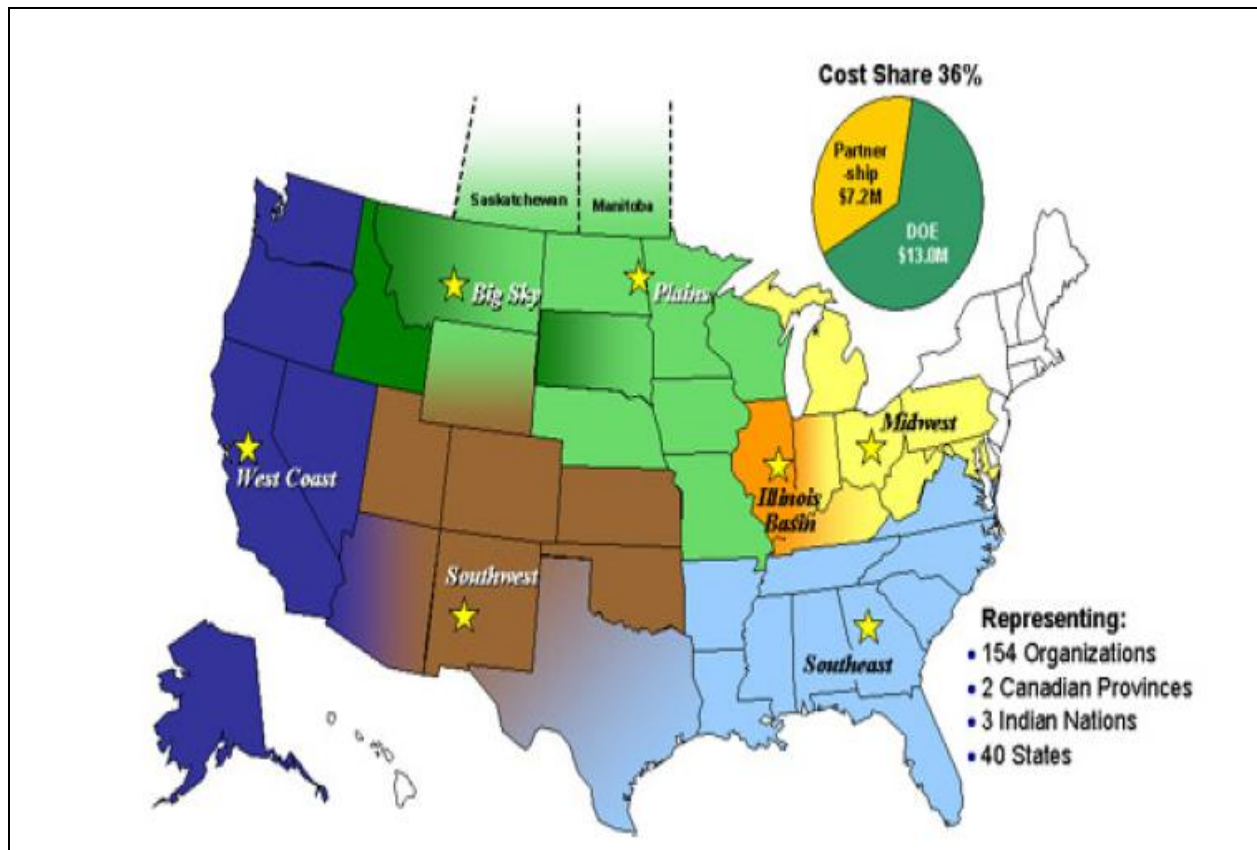
Figure 15: Makeup of the Seven DOE Regional Partnerships (c. September 2005)

The MRCSP region's geology is diverse, encompassing the Northern Appalachian Basin, the Atlantic Coastal Plain, the Michigan Basin, and the Arches Province. The geologic sequestration options of the region are many and varied, including numerous deep saline formations (DSF) available across much of the region, large active and depleted oil and gas fields in the Michigan Basin and the Northern Appalachian Basin, and one of the nation's largest accumulations of coal in the Northern Appalachian Basin. [4.1]

This MRCSP region has more than 500 gigatons of geologic CO_2 storage potential (GtCO_2). This is an immense natural resource that could accommodate many hundreds of year's worth of current CO_2 emissions from the region's large point sources such as electric power plants, cement plants, and refineries. [4.1]

The MRCSP Phase I geologic characterization efforts focused primarily on four reservoir classes: deep saline formations, oil and gas fields, unmineable coalbeds, and organic shales (in laboratory scale). [4.1]

Based on the MRCSP's analysis to date, the MRCSP Region's deep saline formations hold the greatest potential to store large quantities of CO_2.

The deep saline formations, especially Mt. Simon, St. Peter and Rose Run sandstones are by far, the region's largest assets for long-term geologic CO_2 sequestration. The region's deep saline formations could potentially store 450-500 $GtCO_2$.

There is at least 2.5 Gt CO_2 of potential storage capacity in existing and depleted oil and gas fields. Storing CO_2 in these formations via enhanced oil recovery methods in current and recently abandoned regional oil fields could lead to the production of potentially hundreds of millions of barrel s of additional oil production.

Not only is there tremendous potential for carbon sequestration technologies to deploy in the future within the MRCSP, but at a very real level, one can say this is already happening and that the MRCSP region represents one of the leading locations worldwide for the early implementation of these critical carbon management technologies. The MRCSP Region is home to: [4.2]

● The world's first geologic storage experiment located at an operational power plant (the Mountaineer coal-fired power plant),
● One commercial power plant that is already capturing CO_2 with an amine scrubber (the AES Warrior Run coal-fired power plant) and at least, three commercial IGCC units in advanced stages of planning are likely to be built in the region.
● More than 10 miles of dedicated CO_2 pipelines are serving commercial CO_2-driven enhanced oil recovery in Michigan.
●The region has an extensive history of restoring mine lands and already has commercial experience with implementing no-till agricultural methods and other promising terrestrial sequestration options.

4.2.2 General geologic storage potential in MRCSP

MRCSP Oil and Gas Reservoirs [4.3]

The MRCSP Region has many opportunities for CO_2 sequestration in oil and gas reservoirs. Exploration for oil in the Region began in 1859 with the discovery of oil by Colonel Drake in Oil City, Pennsylvania. In addition, significant amounts of natural gas are stored in the region. Such large volumes of gas storage capacity (both natural and engineered) strongly suggest that CO_2 gas can be successfully managed in subsurface reservoirs within the region. The oil and gas fields in the region are most concentrated in the Appalachian and Michigan sedimentary basins. Research suggests that oil and gas fields have a potential sequestration capacity of at least 2,760 million tons of CO_2. Much of this capacity is intermixed with deep saline formations. In fact, it may be difficult to differentiate the two formations in many areas.

Key oil and gas rock formations in the Appalachian Basin include Devonian shales, "Clinton"/Medina/Tuscarora sandstones, the Oriskany sandstone, and the Rose Run sandstone.
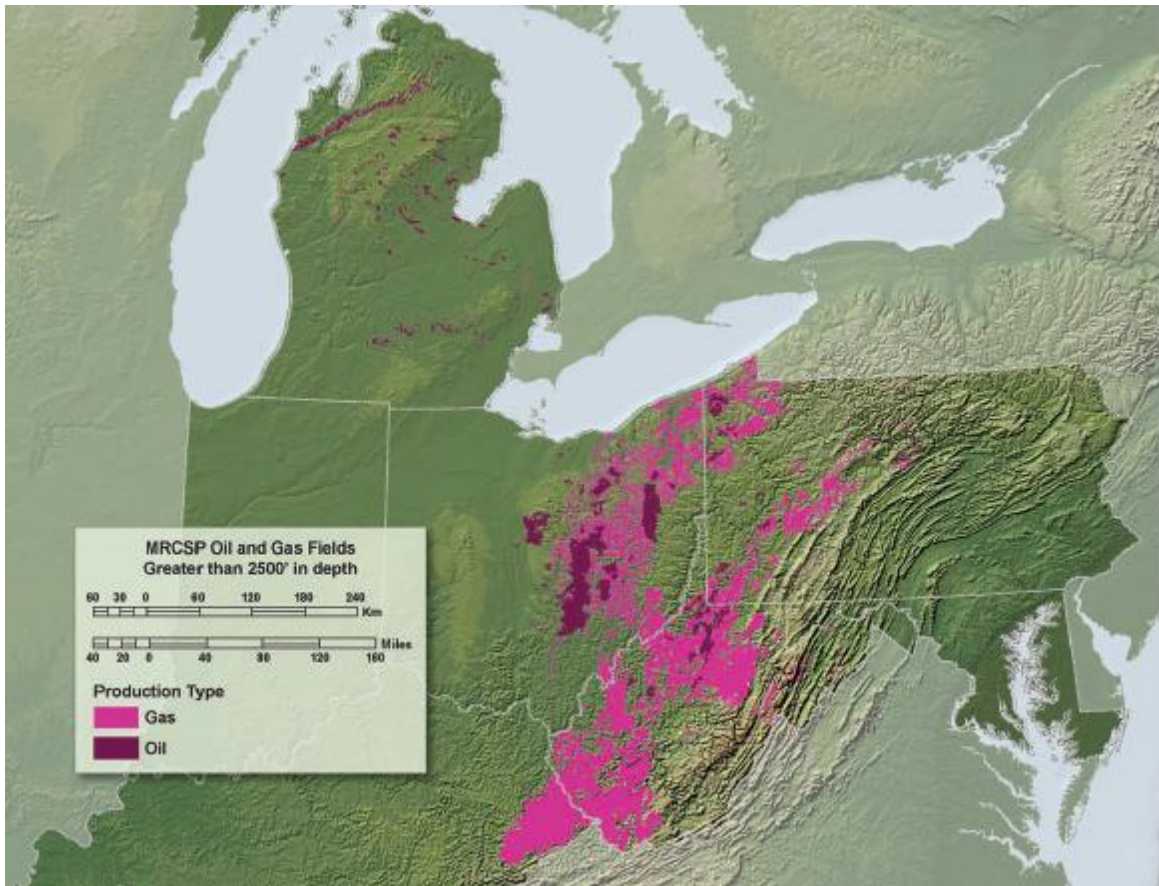
Figure 16: MRSCP Oil and Gas Fields as targets for carbon sequestration

MRCSP Deep Saline Formations [4.3]

Deep saline rock formations are, by far, the MRCSP Region's largest assets for long-term geologic CO_2 sequestration. Initial mapping indicates that the region's well-defined deep saline formations could potentially sequester up to 208,000 million tons of CO_2. The estimated CO_2 storage capacity for the Region is very large compared to present-day emissions, enough to accommodate CO_2 emissions from large stationary sources in the region for hundreds of years. Saline formations in the MRCSP Region are widespread, close to many large CO_2 sources, and are thought to have large pore volumes available for injection use. The region is additionally considered a fairly stable geologic setting.

The storage capacity in each reservoir is largely a function of its spatial extent, thickness, and porosity. Given its presence in much of the MRCSP Region, the saline formation with the largest capacity in the Region is the Mt. Simon Sandstone, followed by the St. Peter Sandstone and the Medina/Tuscarora Sandstone. Other notable target formations include the Rose Run Sandstone, the Oriskany Sandstone, and the Sylvania Sandstone. While Michigan has the highest storage potential, all of the seven states in the MRCSP Region have the capacity to store large amounts of CO_2 in deep saline formations.
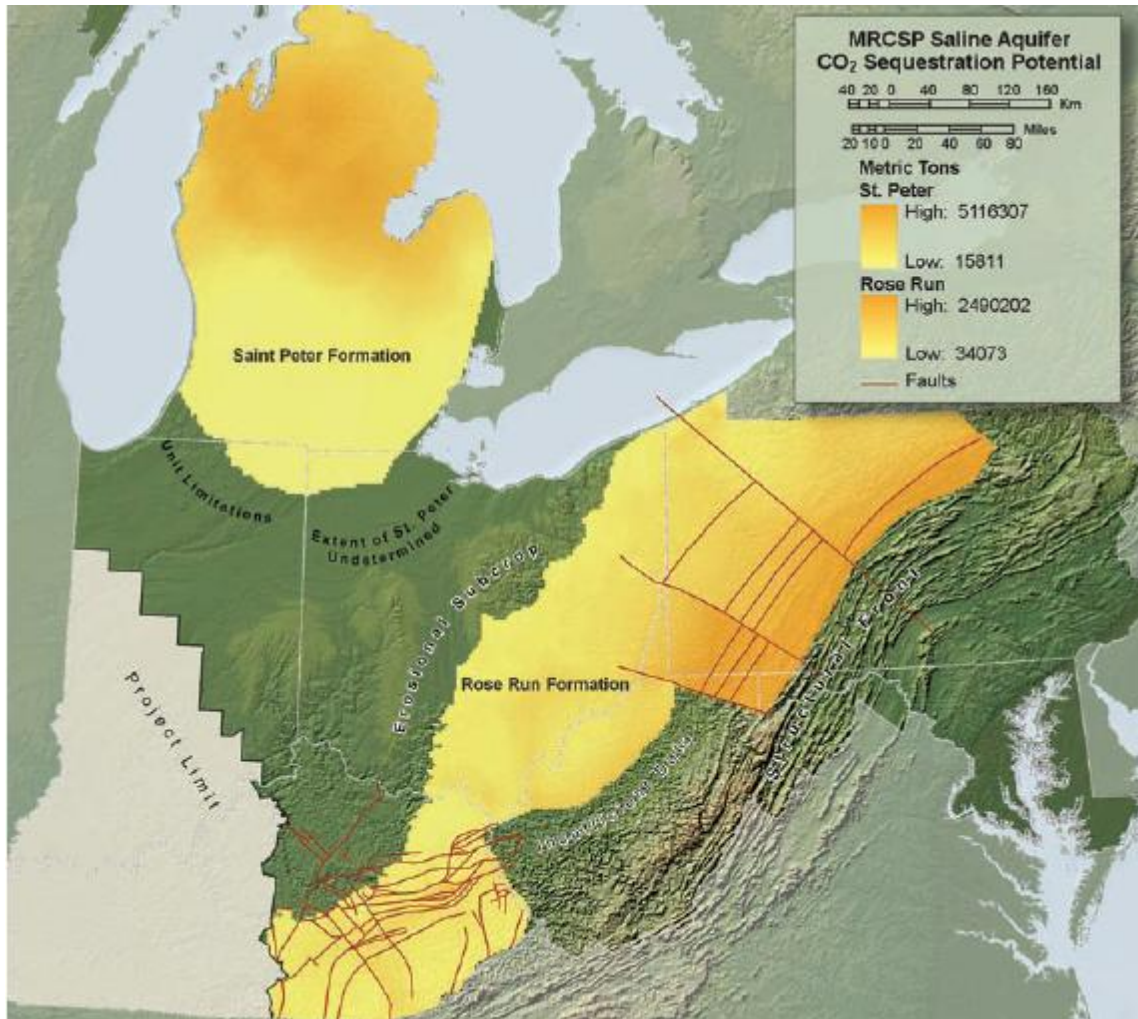
Figure 17: Saint Peter and Rose Run formations

4.3 Carbon Storage Site Selection---Rose Run

4.3.1 Deep Hydrostratigraphic Unit

The Rose Run sandstone is located across Ohio, Pennsylvania, Kentucky, West Virginia and Maryland. It crops out in eastern of Ohio. Suitable formations for geologic storage of CO_2 are deep, thick, regions that are regionally extensive, filled with saline waters, and separated from freshwater aquifers and other formations of economic interest by a significant interval of low permeability cap-rock. For CO_2 disposal applications, a minimum depth of approximately 2,500 ft is required to maintain the pressure for retaining CO_2 in a dense, supercritical fluid phase. [4.4]

Supercritical CO_2 has a density of approximately 0.7, and formation fluids have a density of approximately 1.05 to 1.25. Consequently, the injected CO_2 is expected to move upward within the formations due to density-driven flow.

Shale, limestone, and dolomite layers form the major containment units to limit vertical migration of any injected CO_2. The Beekmantown, Black River, and Reedsville provide containment above the Rose

25

Run Sandstone. The Beekmantown is a dense dolomite and the Black River is a limestone and dolomite mixture, with a combined thickness of 1,400 ft. The Reedsville is uniform shale, which is considered an excellent confining layer. The shale formations have very low effective porosity of <1% and permeability is often below 1E-6 mD. In general, containment units appear to be present above the target injection layers that are more than adequate to prevent any upward migration of CO_2. [4.5]

According to the research, the containment unit of the Rose Run is approximately 200 ft thick and primarily shale with very low permeability and porosity. [4.5] Also, containment layers are diverse and extensive. This is exemplified by the presence of oil and natural gas production and underground waste disposal and natural gas storage facilities that utilize the Rose Run sandstones, as well as several other formations. This suggests an excellent setting for long-term storage of CO_2. [4.4]

In addition, the overlying containment units separate the injection intervals from any underground sources of drinking water (USCWs).[4.5]

4.3.2 Hydraulic Parameters

The main hydraulic parameters measured in formations are permeability and porosity (Table 6). A review of the data illustrates that the parameters are very site-specific. Permeability, especially, may vary over several orders of magnitude within a formation due to variations in the nature of the rock. Porosity is generally more consistent. [4.5] The testing method also can have a large impact on results.

Our CCS project sequestration site is base on two scenarios. One scenario is the storage underlying our Shawville plant with a radius of 25 miles. Another scenario is to the depleted oil and gas reservoir using (EGR) model. We determine the Colfax Field located in Fairfield County, OH. The potential sequestration sites are both in Rose Run formation. We will then do the cost analysis based two scenarios to find athe best sequestration strategy.

The table shows the basic parameters studied for our site.

Table 6: Hydraulic Parameters of Rose Run

	Depth [a] (ft)	Thickness [a]	Permeability(mD)		Porosity(%)		Pressure Gradient (psia/ft)	Formation Fluid Temperature (1°F/100ft)	Bulk Density Representative
			Regional [b]	Site [c]	Regional [b]	Site [c]			
Rose Run Sandstone	2,500-11,000	50-200	0.01-198	N/A	2-25	N/A	0.41-0.46	1-1.2	**2.2-2.8**
Underlying Shawville, Clearfield, PA	**7,550**	**75-150**	**N/A**	**13-86**	**N/A**	**8-14**	**0.43-0.46**	**1**	**2.6**

(a)---Approximation values based on nearby deep well.
(b)---Approximation values based on regional summary data
(c)---Approximation values based on nearby deep wells or gas fields

The Rose Run Sandstone has a low seismic hazard risk rating, and injection is unlikely to cause seismic activity unless injection occurs in a faulted interval.[4.4] No extensive faulting or fracturing is present in the study area.

Virtually all bedrock in the study area contains groundwater with TDS above the underground source of drinking water criteria of 10,000mg/L. For the Rose Run formation, even shallow bedrock wells produce water with TDS of well over 20,000mg/L. Consequently, the bedrock aquifers are not used as a source of drinking water in the area. TDS continues to increase with depth. With the depth ranging from 4180 ft to 4270 ft, TDS is always higher than 287,000mg/L and reaches to 313,000mg/L.

Figure 18 shows the locations of the Rose Run sandstone, a deep saline formation identified by the MRCSP as a potential carbon sequestration site [4.6]. As the figure shows, the plants all lie above or near to this formation, so suitable CO_2 injection sites presumably could be located very near to each of these plants.[4.6] The starts indicates the location of the Colfax Field. The black triangle with the yellow boundary is the location of Shawville.
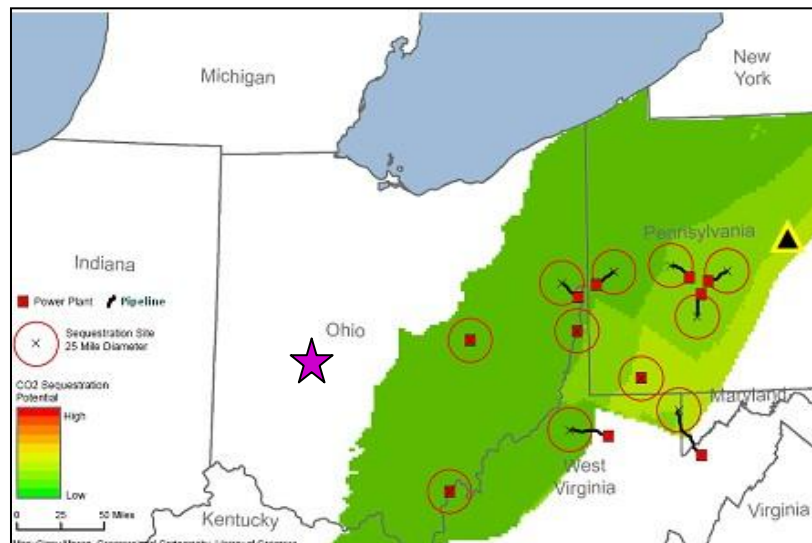
Figure 18: Major Power Plant and the Rose Run Formation

4.4 Reservoir Capacity Estimates

Estimates on reservoir capacity were calculated to provide some guidance on the amount of fluid that may be injected in the target formations. These capacities are an approximation involving many assumptions, and more detailed modeling is required to assess injection capacities. However, the methods are suitable for initial investigations. [4.5]

The estimates of the amount of CO_2 that may be injected into the target reservoirs at the area of interest were calculated using the equation proposed by van der Straten (1996) in the Joule II report: [4.5]

$$Q = V_p \, h_{st} \, \rho_{CO2} \qquad\qquad (2)$$

where,
$\qquad V_p = V_b(\text{Net:Gross})\phi$,

V_b = bulk aquifer volume (km3),
Net:Gross = percentage of porous, permeable rock,
φ = formation porosity (%),
h_{st} = storage efficiency (i.e., fraction of pore volume that can be filled with CO_2 [%]),
$ρ_{CO2}$ = density of CO_2 (700 kg/m3) and,
Q = storage capacity (Mt).

This equation is not a simple pore volume calculation, as it accounts for reservoir heterogeneity and inefficiencies in storage. It does assume that the injection formation is a homogeneous, "open" aquifer in which the entire volume is available for the injected CO_2. In the equation, storage capacity is a function of the bulk aquifer volume, the formation porosity, the percentage of the formation that is permeable rock, the storage efficiency of the formation, and the density of CO_2. Porosity and volume may be determined from nearby wells and isopach maps. Another way of calculating capacity has been shown in sequestration part. Density of CO_2 is 700 kg/m^3. The ratio of net to gross permeable rock accounts for heterogeneity in the rock formation that may reduce its effective thickness. Similarly, storage efficiency accounts for the fraction of pore space available for injection. [4.5]

The ratio of permeable to impermeable rocks was assumed to be 75% for the base case. Low ratio was estimated at 50% and high ratio was estimated at 95%. Storage efficiency was assumed at 6% of available porosity. [4.5] The effective thickness underlying Shawville plant is 75-150 ft and its capacity would be 244Mt to 1024Mt CO_2. Figure 19 illustrates the effect of porosity and the ratio of permeable to impermeable rocks. As shown, porosity has the largest effect on reservoir capacity and is a key hydraulic parameter of the injection reservoir.
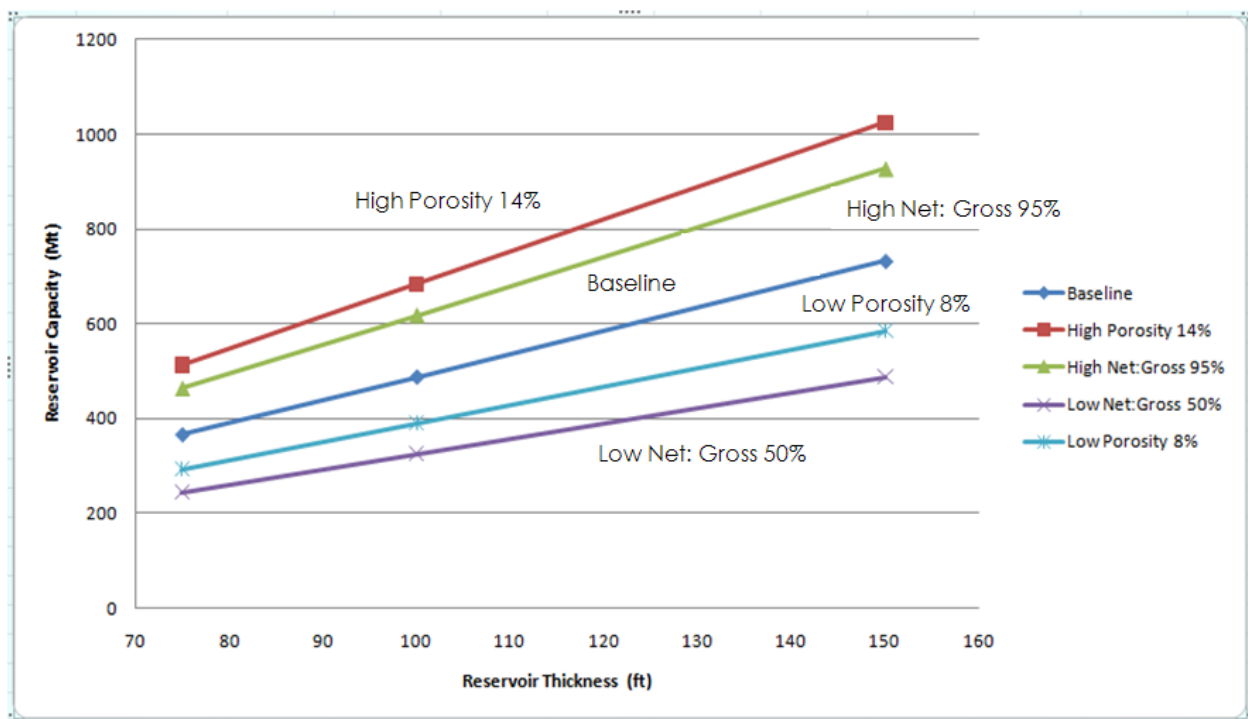
Figure 19: Estimated Injection Capacities underlying Shawville for a 25-mile radius injection site

4.5 Transportation

Carbon dioxide transportation via pipeline is an established technology with an established regulatory framework---with the MRCSP Region, dedicated CO_2 pipelines will be the primary means of transporting CO_2 from the point at which is captured to a suitable, long-term geologic storage site.

Carbon dioxide may be transmitted via pipeline as a low pressure gas or a supercritical fluid. Pipeline transmission as a supercritical fluid (compressed to 1073 – 3046 psi (7.4 - 21 MPa)) is considered the most reliable and cost effective method for transporting large amounts of CO_2. In the supercritical phase CO_2 has characteristics of both a liquid and gas, maintaining the compressibility of a gas while having some of the properties, such as density, of a liquid. Low viscosity is important for pipeline transport and the viscosity of CO_2 in the supercritical phase is the same as in the gas phase, which is 100 times lower than the liquid phase. Important from a cost standpoint, supercritical transport allows for substantially higher throughput through a given pipe cross-section than transport at lower gas pressures. [4.1]

The oldest long-distance CO_2 pipeline in the United States is the 140 mile Canyon Reef Carriers Pipeline (in Texas), which began service in 1972 for EOR in regional oil fields. Other large CO_2 pipelines constructed since then, mostly in the Western United States, have expanded the CO_2 pipeline network for EOR. These pipelines carry CO_2 from naturally occurring underground reservoirs, natural gas processing facilities, ammonia manufacturing plants, and a large coal gasification project to oil fields. Additional pipelines may carry CO_2 from other manmade sources to supply a range of industrial applications. Altogether, approximately 3,600 miles (5,800 km) of CO_2 pipeline operate today in the United States. Modern control technologies help to ensure pipeline integrity and safety—a pipeline section that is damaged can be quickly shut down, limiting the loss of CO_2. [4.7]

Other transportation modes generally refer to rail or truck transport that is in widespread use in the marketplace serving the food and beverage industries, specialty gas industry, and the oil and natural gas hydraulic fracturing business.

Pipeline transportation is believed as the most economical type for large quantity of CO_2 both for long and short distances.

4.5.1 Scenarios for CO_2 pipeline

Under a national CCS policy, a key question is how establish a CO_2 pipeline network at the lowest social and economic cost given the current locations of existing CO_2 source facilities and the locations of future sequestration sites. One recent analysis, for example concluded that 77% of the total annual CO_2 captured from the major North American sources could be stored in reservoirs directly underlying these sources, and that an additional 18% could be stored within 100 miles of additional sources [4.6]. Other analysts suggest that captured CO_2 may need to be sequestered, at least initially, in more centralized reservoirs to reduce potential risks associated with CO_2 leaks.[4.8] They suggest that, given current uncertainty about the suitability of various on-site geological formations for long-term CO_2 storage, certain specific types of formations (e.g., salt caverns) may be preferred as CO_2 repositories because they have adequate capacity and are most likely to retain sequestered CO_2 indefinitely. A third scenario envisions CO_2 sequestration, at least initially, at active oil fields where injection of CO_2, may be profitably employed for enhanced oil recovery (EOR). [4.9]

Whether CCS policies ultimately lead to centralized or decentralized storage configurations remains to be seen; however, pipeline requirements and storage configurations are closely related. A 2007 at the Massachusetts Institute of Technology (MIT) concluded that 'the majority of coal-fired power plants are situated in regions where there are high expectations of having CO_2 sequestrations sites nearby.'[4.10]

For our project, we determine to choose the Colfax Field as the preferred sequestration site and stored underlying Shawville plant as well. In such cases, we prefer to construct our pipelines using the third and first scenarios to store the CO_2. The former demands the pipeline length around 250 miles and the latter within a 25 miles radius.

4.5.2 Special design consideration for CO_2 transmission system

Pipelines used for the transmission of CO_2 are very similar to those used for natural gas; however, CO_2 has different properties that must be accounted for in the design of pipelines and other CO_2 handling systems. Additionally, the CO_2 stream captured from point sources and meant for geologic storage would invariably contain some impurities. The gas mixture make-up is also an important consideration in the design of pipelines.

Some of the special considerations in the design of CO_2 pipelines are the following:

- In selecting the materials for use in CO_2 pipelines, the corrosion rate must be established for various temperatures and partial pressures of carbon dioxide. In relatively higher concentrations of carbonic acid, use of corrosion resistant materials provided with erosion protection has been recommended. These areas are typically located downstream of valves and in the vicinity of pumps. (Barrie 2003)
- Water, hydrocarbons and carbon dioxide may also combine to form hydrates that could plug the system. Minimizing the moisture content of the carbon dioxide stream is essential.

- Many lubricants, both synthetic and petroleum-based, harden in contact with CO_2 and become ineffective.

- Dry CO_2 has poor lubricating properties requiring special design features for pumps, compressors, etc.

- Carbon dioxide cools dramatically during decompression so pressure and temperature must be carefully controlled during depressurizing line segments and other routine maintenance activities.

- The CO_2 pipelines require some built-in surge capacities to minimize the potential for "water hammers" that can occur during flow changes.

- Supercritical CO_2 provides favorable conditions for the propagation of fractures requiring counter-measures such as installation of fracture arrestors on the pipeline.

- Carbon dioxide pipelines are typically buried except at the metering and compressor stations and under deep water. The seasonal temperature variations usually do not affect the fluid conditions in the pipeline. However, if the seasonal temperature variations are likely to impact the pipeline temperature, then those should be accounted for in design. [4.1]

Impurities impact compressibility of CO_2 and result in reduced flows through the pipeline. Specific to the CO_2 sources in the Midwestern region, the levels of impurities left after purification are unlikely to have much detrimental impact on pipeline capacity. [4.1]For our project, under certain capture techniques CO_2 in pipelines are assumed to be pure without impurities.

4.5.2 Pipeline Right of Way Consideration (ROW)

Siting a pipeline entails obtaining the proper regulatory permits and acquiring use of the land that the pipeline will occupy. Depending on the location of the proposed pipeline, environmental impact assessments, permitting, and acquisition of rights of way can take several years. After a pipeline route has been approved, land along the route must be acquired by an easement agreement, by purchase, or via eminent domain.

A pipeline right of way consists of a parcel of land under which a pipeline is buried. Rights of way are often about 50 feet (15 meters) wide. Right of way usually refers to access to a portion of a side of a street or an easement on private property granted to a utility. A right of way agreement between the pipeline company and a landowner is a form of easement (a limited perpetual interest in land that allows the pipeline owner to construct, operate, and maintain a pipeline across the land). An easement does not grant an unlimited entitlement to use the right of way. Pipeline companies are responsible for the right of way. The rights of the easement owner (Pipeline Company) are set out in the easement agreement.

Acquiring rights of way for CO_2 pipelines do not add much to the overall cost of a large CO_2 capture and storage project but acquiring these rights can take many years of negotiations with landowners, performing environmental impact studies, obtaining permits from various regulatory agencies and public service commissions. Within the MRCSP region, a promising approach to minimizing the cost and accelerating the acquisition of needed CO_2 pipeline rights of way could well center on making "shared use" of existing right of way corridors

4.6 CO2 Transportation Cost

Carbon capture and storage requires CO_2 to be transported to a storage site. In this project, the Rose Runs sandstone is chosen as the sequestration site with using two pipeline scenarios. We need to determine inlet/outlet pressure, temperature, design CO_2 mass flow and pipeline characteristics such as diameter and pipeline length. Combined with the economic parameters, such as the fixed charge factor, and operating and maintenance charges as input, we could finally get the value for pipeline transported CO_2 which is sequestered in deep saline aquifers.

It is generally recommended that a CO_2 pipeline operate at pressures greater than 1250 psia (8.6 MPa) where the sharp changes in compressibility of CO_2 can be avoided across a range of temperatures that may be encountered in the pipeline system [4.11]. Conversely, line-pipe with ASME-ANSI 900# flanges has a maximum allowable operating pressure of 2300 psia (15.3 MPa) at 38°C (100.4°F). [4.12]

4.6.1 Basic Assumption

At this stage, we consider one-to-one source-sink matching only, that is, we look at transportation CO_2 from one emission source or node to exactly one injection site.

Table 7: Case study input parameters and distributions for the transport models

Parameters	Rep. Value	Distribuition
Design CO_2 Mass Flow(Mt/year)	3.4	Uniform
Power Plant Capacity Factor(%)	90%	Uniform
Capital Recovery Factor	0.15/yr	Constant
Pipeline Transport Model Parameters		
Inlet Temperature(°F)	53.6	Constant
Inlet Pressure(pisa)/(Mpa)	2200/15.2	Constant
Outlet Pressure(psia)/(MPa)	1500/10.3	Constant
Total Pipeline Length(ft)	132000/1320000	Uniform
Pipeline Elevation Change(m)	0	Constant

4.6.2 Calculations of Compressors & Pump Power Requirements

After CO_2 is separated from the flue gases of a power plant or energy complex (i.e., captured), it must be compressed from atmospheric pressure (Pinitial = 435psia), at which point it exists as a gas, up to a pressure suitable for pipeline transport (Pfinal = 2200psia), at which point it is in either the liquid or 'dense phase' regions, depending on its temperature. Therefore, CO_2 undergoes a phase transition somewhere between these initial and final pressures. When CO_2 is in the gas phase, a compressor is required for compression, but when CO_2 is in the liquid/dense phase, a pump can be used to boost the pressure. It can be assumed that the 'cut-off' pressure (Pcut-off) for switching from a compressor to a pump is the critical pressure of CO_2, which is 1070 psia. Hence, a compressor will be used from 435psia to 1070 psia, and then a pump will be used from 1070 psia to 2200psia.

Pinitial = 435 psia

Pfinal = 2200 psia

Pcut-off = 1070 psia

In this project, two scenarios will lead to different values with respect to compression power requirement. An important technical consideration in the design of pipelines for transport of supercritical CO_2 is that the CO_2 remains above critical pressure. This can be achieved by means of

recompression of the CO_2 at certain points along the length of the pipeline. Recompression is often needed for pipelines over 475200 ft in length. For the longer distance scenario, we add two more recompression systems since the pipeline length is 1320000 ft. The detailed formula is showed in Appendix A. Table 8 shows the results for two scenarios.

Table 8: Calculated power requirements for two storage site

Scenario	One (Underlying Plant Storage)	Two (For EOG)
Compression Power Requirement	3.24E+03 (kW)	9.73E+03(kW)

4.6.3 Capital, O&M, and Levelized Costs of CO_2 Compression and Pumping

The following table and figures show our cost estimation of the capital cost due to power required for two scenarios in our project.

Table 9: Cost of Capital, O&M, and Levelized Costs of CO_2 Compression and Pumping

Scenario	One (Underlying Storage)	Two (For EOG)
Capital Cost of Compressor(s)[$]	8.39E+06 /compressor	2.52E+07/3 compressors
Capital Cost of Pump(s) [$]	1.88E+06	1.88E+06
Capital Recovery Factor	0.15/yr	0.15/yr
Annualized Capital Cost of Compressor(s) and Pump(s) [$/yr]	1.54E+06	4.06E+06
Levelized Capital Cost [$/tone CO_2]	0.5034	1.3261
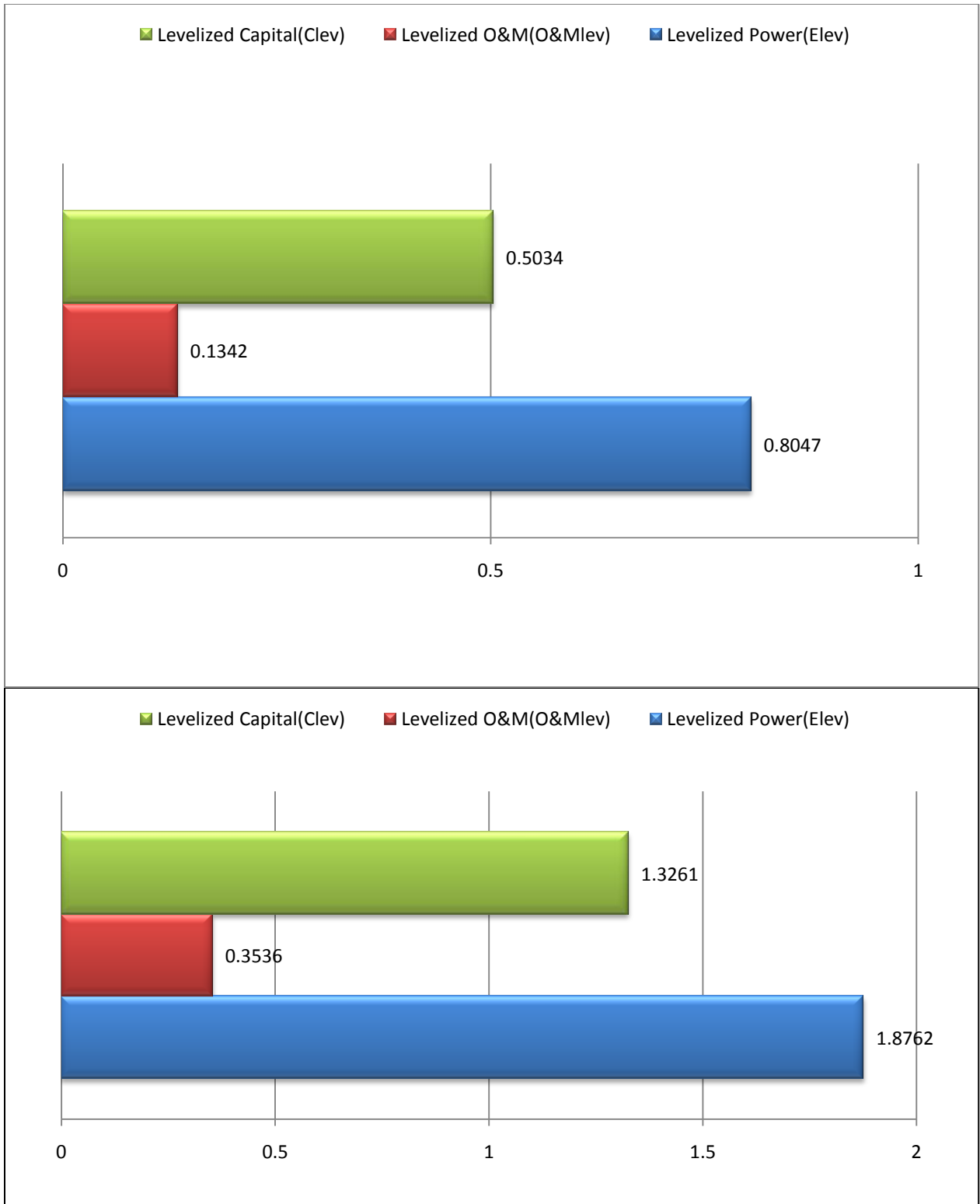
Figure 20: Visualizing the Levelized Capital, O&M and Power cost [$/ton CO$_2$]

From Figure 20 it is seen that electricity power cost outweighs the other two costs. A key parameter impacting the electricity power cost is the price. In this project, the price of electricity is $0.065/kWh.
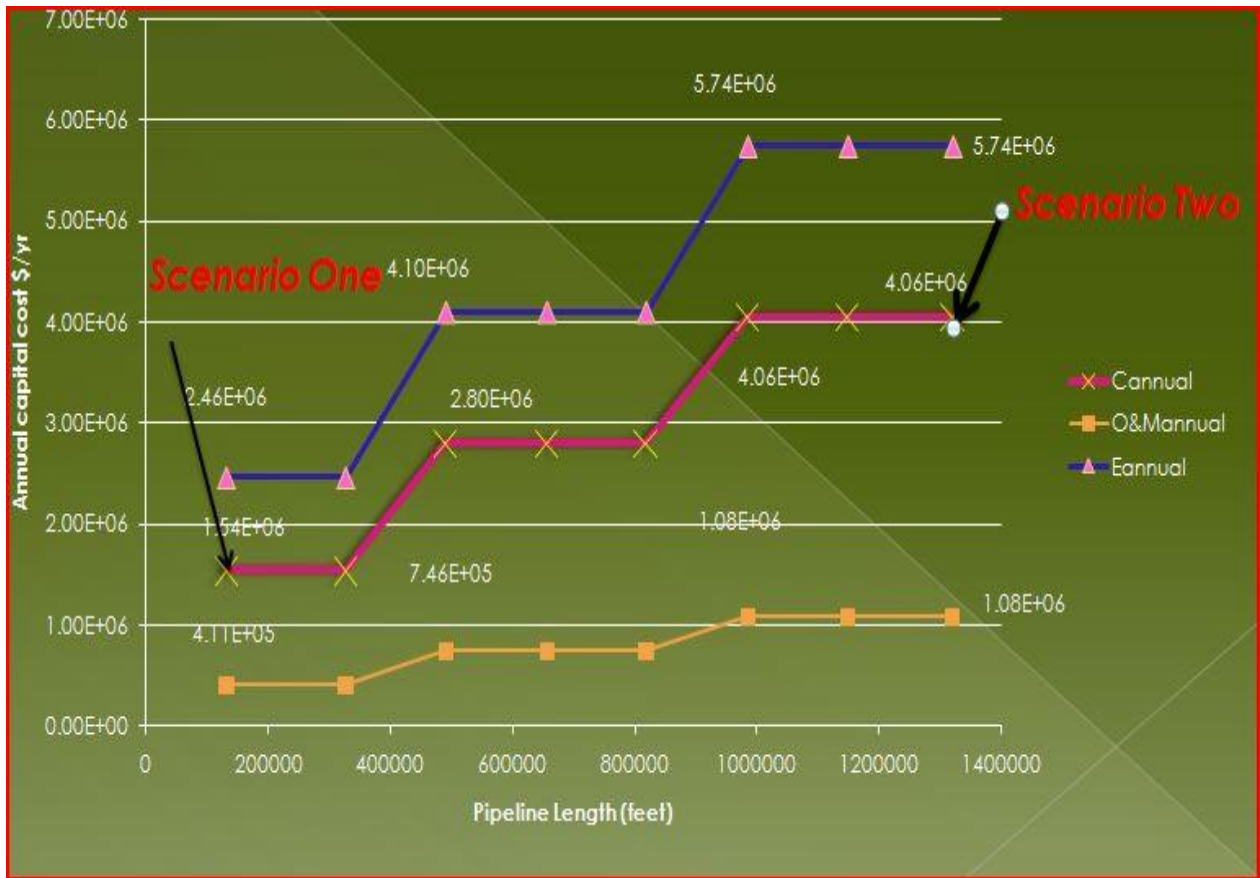
Figure 21: Annualized costs as a function of Pipeline Length

This figure shows the annual cost of capital cost of compressors and pumps; operation and maintenance and electric power vs. different pipeline length under the same CO_2 emission per year and same capital factor.

As the result, we determine the total annual cost with respect to compressors and pumps power requirements by adding the annualized capital cost of compressors and pumps, annual O&M cost and total annual electric power costs of compressor and pumps up. For the first strategy we achieve the value of 4.41E+06 $/yr, while another is of 1.09E+07 $/yr. And the levelized values are 1.4423 $/tonne$CO_2$ and 3.5559 $/tonne$CO_2$ respectively.

4.6.4 Determine the diameter of pipeline

It is assumed that the transportation distance for the Colfax Field is 250 miles away from the Shawville plant and underlying storage radius is 25 miles. It's a 572MW coal plant with CO_2 emission of 3.4 million tons/year and the capital factor is 0.9. The diameter needs to be found using some equations and assume supercritical CO_2 as an incompressible fluid and the pipeline flow and pumping processes as isothermal.
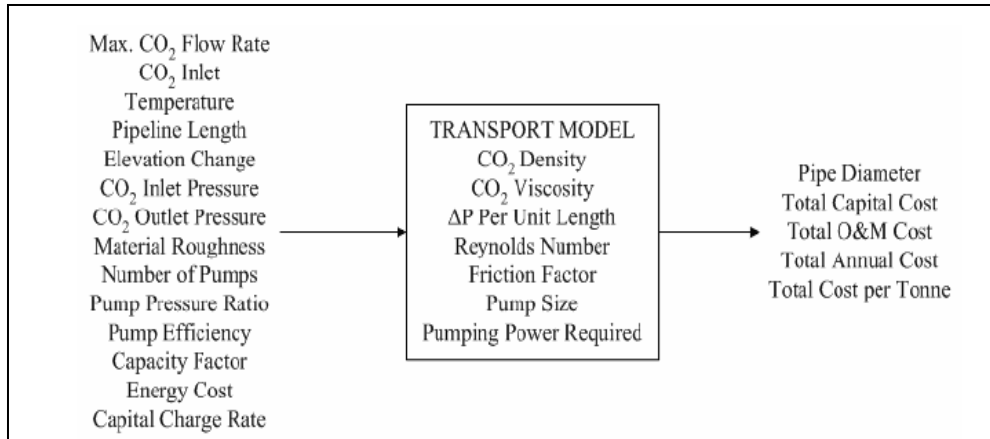
Since the calculation of pipeline diameter is an iterative process, one must first guess a value for diameter (D). A reasonable first approximation is D=10inches. An estimation of the density (ρ) and viscosity (μ) of CO_2 in the pipeline (approximated at T and Pinter) is also required. We choose to use [4.13] to get approximation values using actual values form Kinder Morgan. Finally, the solutions are 10 inches for the pipeline length of 25 miles and 16 inches for the pipeline length of 250 miles.

4.6.5 Capital, O&M, Levelized Costs for CO2 Transportation

Transportation costs comprise the capital cost of pipeline construction and annual pipeline operation and maintenance (O&M) costs. The pipeline O&M cost is held at $5,000/mile per year, independent of pipeline diameter. [4.14]

We compare with three engineering-economic models of pipeline transportation of CO_2 which are Ogden Model, MIT Model correlation and the CMU Model. Finally we confirm to use CMU correlation which takes into account regional differences in pipeline construction costs by using regional variables called 'Region weights'. For the Midwest, the region weight is 1.516.
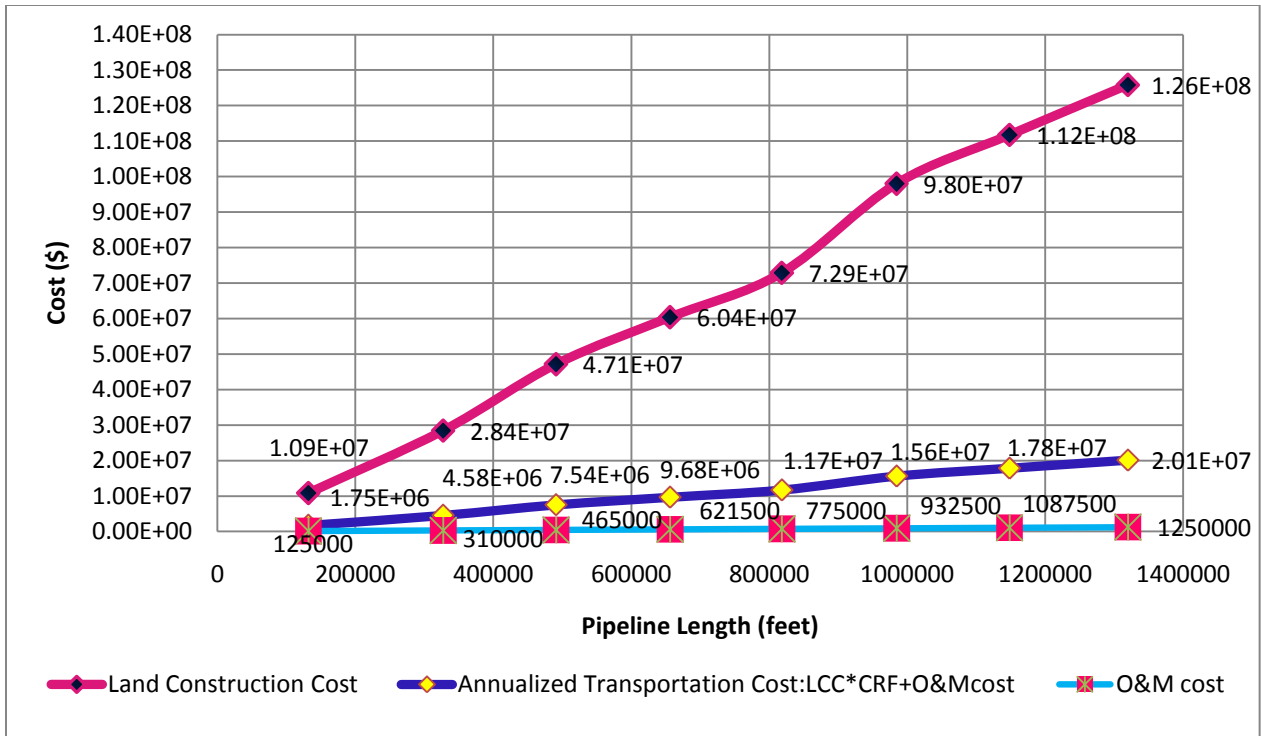
Figure 23: Transportation Cost as a Function of CO_2 Pipeline Length

The Land Construction Cost (LCC) of CMU correlation differs in that it departs from the linearity restriction in the MIT correlation and allows a double-log (nonlinear) relationship between pipeline land construction cost and pipeline diameter and length.
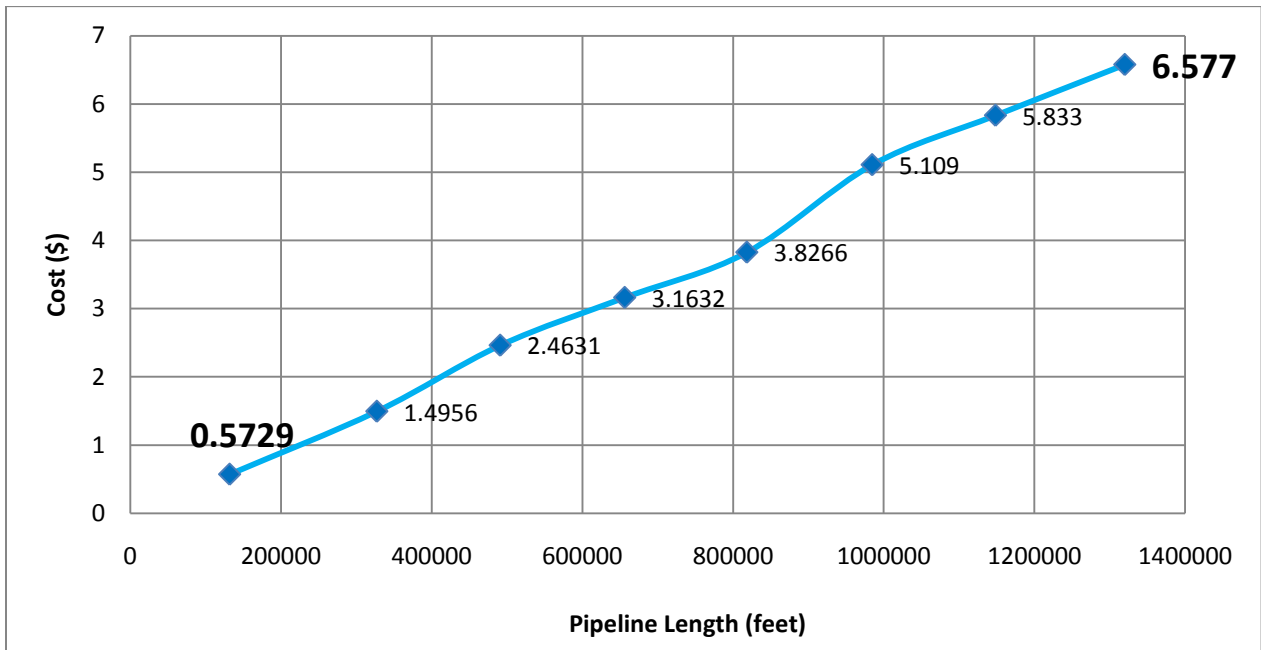
Figure 24: Leveliaze Transportation Cost as a Function of CO_2 Pipeline Length
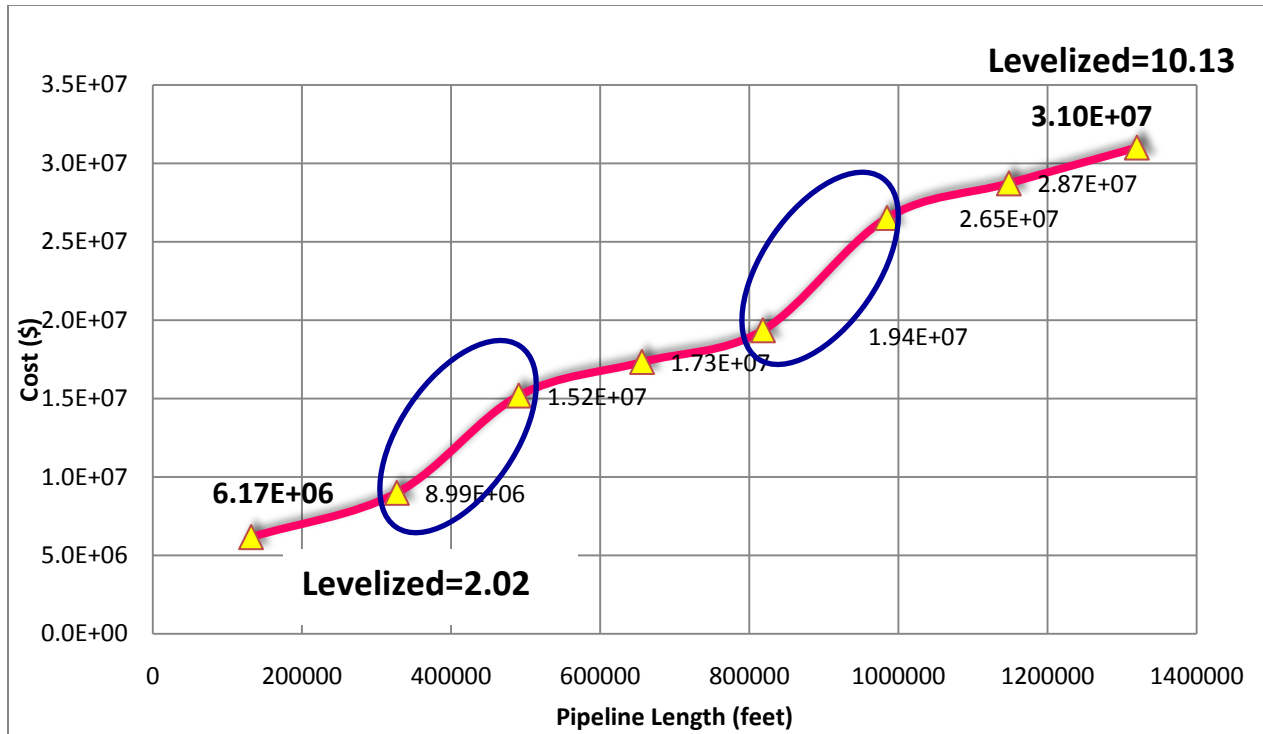
Figure 25: Total Annual Cost as a Function of CO_2 Pipeline Length

The final step is to combine the power consumption and transportation annualized cost together as a function of pipeline length. In the Figure 25, the first sharper slope in a blue cycle is because of the recompression and increase of diameter of pipeline. This could also explain the second sharper slope.

Table 10: Conclusion of Transportation Cost

Scenario	One (Underlying Plant Storage)	Two (For EOG)
Combined Annual Total Cost (Power Consumption+Transporation)[$/yr]	6.17E+06	2.02
Levelized [$/tone CO_2]	3.10E+07	10.13

4.7 Future work

At this stage, we only consider the source-sink matching while future work focuses on many-to-many sources-to-sinks matching. Carbon dioxide may be transported directly to a storage site, or, where a large network of pipelines exists, it may be transported to a pipeline hub to join CO_2 collected from other sources and subsequently piped to a storage site. And then we may establish economic model of transportation and storage on this basis.

The cost of CO_2 transportation is a function of pipeline length (among other factors), which in turn is determined by the location of sequestration sites relative to CO_2 sources. Some analysts believe that CO_2 pipeline costs will be moderated in the future because generating companies will construct new

power plants geographically near sequestration sites. Recent network cost models suggest otherwise. On a mile-for-mile basis, these models show that electricity transmission costs (including capital, operations, maintenance, and electric line losses) generally outweigh CO_2 pipeline costs in new construction. Accordingly, the least costly site for a new power plant tends to be nearer the electricity consumers (cities) rather than nearer the sequestration sites if the two are geographically separated.[4.6]

Any company seeking to construct a CO_2 pipeline must secure siting approval from the relevant regulatory authorities and must subsequently secure rights of way from landowners. There is no federal authority over CO_2 pipeline siting, so it is regulated to varying degrees by the states (as is the case for oil pipelines). The state by- state siting approval process for CO_2 pipelines may be complex and protracted, and may face public opposition, especially in populated or environmentally sensitive areas. Questions arise as to the right of easement holders to install CO_2 pipelines, compensation for use of such easements, and whether existing easements can be sold or leased to CO_2 pipeline companies. Although these siting issues may arise for any CO_2 pipeline, they become more challenging as pipeline systems become larger and more interconnected, and cross state lines. If a widespread, interstate CO_2 pipeline network is required to support CCS, the ability to site these pipelines may become an issue requiring new federal initiatives.[4.6]

Furthermore, capacity limitations at favorably located sequestration sites (like the Rose Run formation) may lead to competition among large CO_2 source facilities seeking to secure the best local sequestration sites before others do. Carbon dioxide transportation costs could raise electricity prices even higher above the national average which may become an issue for Congress. [4.6]

Chapter 5: Sequestration of CO_2

5.1 Introduction

Carbon sequestration is a technique for the long-term storage of carbon dioxide. It is a technique of reducing the carbon content in the environment, thereby mitigating the global warming. Carbon dioxide is generated in the atmosphere either by natural sources or by anthropogenic sources.

Carbon dioxide may be captured as a pure by-product in processes related to petroleum refining or from flue gases from power generation. Carbon dioxide can be sequestered in subsurface saline aquifers, reservoirs, ocean water, aging oil fields, or other carbon sinks. After capturing CO_2 from its generation source it is transported by suitable transportation means to the sequestration site, & then is sequestered.

A number of sequestration projects are running throughout the world. United States has a great potential in sequestering CO_2.

Out of many possible sites for sequestration in U.S., Rose Run formation is a very good candidate for sequestering CO_2. This projects concerns the sequestration of carbon dioxide generated by a coal fired

power plant(Shawville, PA, 572MW capacity) in the Rose Run formation with the option of enhanced oil recovery from the depleted oil reservoir(Coal Fex Field).

5.2 Geological Description of Rose Run Formation

The Rose Run formation is in southern Pennsylvania which extends beneath eastern Ohio, New York & Kentucky in the Appalachian Basin of the Eastern United States. The Rose Run Formation is a complex unit that is composed of a mixture of both carbonate and siliciclastic lithologies and is heterogeneous at multiple scales. The stratigraphy study of Rose Run formation shows that it composed of interbedding of 7 major rock types:

Dolomudstone; ooid grainstone; stromatolite boundstone; wavy-bedded shale, sandstone, and carbonate; shale; sandy carbonate; and quartz Sandstone. Clay, quartz sand, and carbonate grains are locally well mixed within single beds. [5.1]   Also, quartz sandstone is locally cemented by carbonate and carbonate ooids   are replaced by quartz so that the beds are compositionally and texturally heterogeneous and carbonate and siliciclastic lithologies are mixed at multiple scales[5.1]. Rose Run & other sandstone formations nearby are rich in glauconite, which is an important alternative of Ca-feldspar as a source of calcium for mineral trapping of CO_2.

After having a look at the geologic properties of Rose Run formation, we can see that it's a very good candidate of sequestering CO_2. The Rose Run Sandstone has the potential to store CO_2 over millennia as a negatively buoyant aqueous solution and, ultimately, as immobile carbonate minerals. Figure 26 shows a measured section of core from sandstone core [6.3].
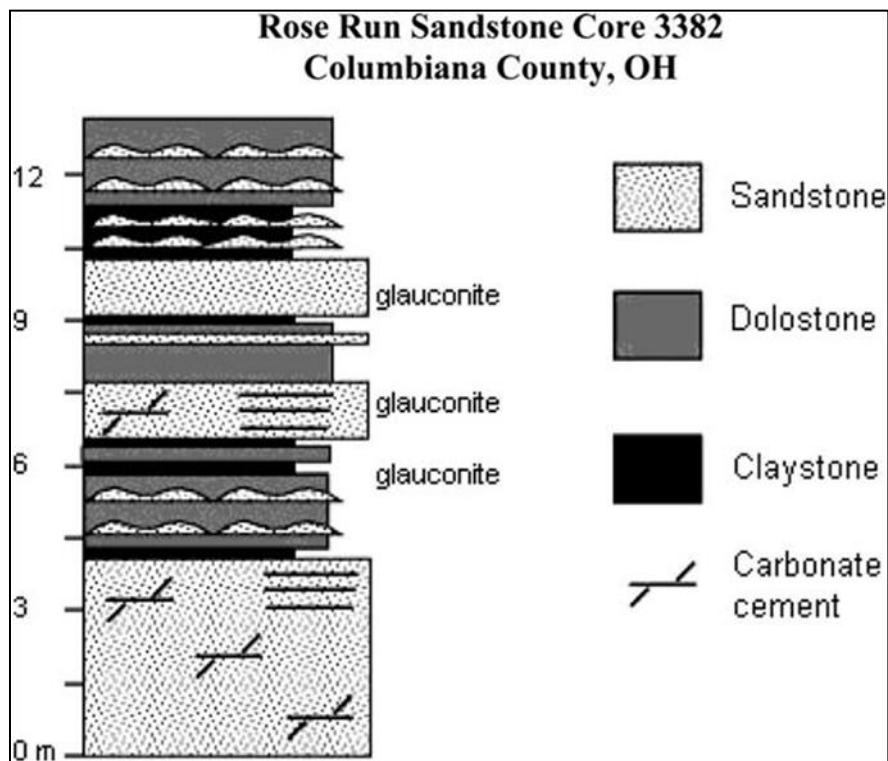
Figure 26: Measured section of core through part of the Rose Run Sandstone

5.3 Suitability of Rose Run Formation For Reliable Carbon Storage in Oil/Gas Reservoirs Within EOR

CO_2 sequestration in the depleted oil/gas reservoirs is the long term solution of mitigating CO_2 concentration in the environment and make thereby reducing global warming. Oil/gas reservoirs have large capacity to store CO_2 for a very long period of times. As recovery in the gas reservoirs(about 65% of OGIP) is more than that in oil reservoirs(35% of OOIP), so gas reservoirs have larger capacity for storing CO_2 than oil reservoirs. But we need to study the phase behavior of CO_2, pure CH_4 and their mixtures, in order to study the sequestration in gas reservoirs.

Suitability of any formation for CO_2 sequestration depends mainly on the 3 factors: capacity, injectivity, containment. Capacity means how much carbon dioxide can be stored in the formation. Total capacity of O & G reservoirs is found to be 675-900*10^9metric tons of CO_2 [5.3].   Injectivity means how fast CO_2 can be pumped in the formation. In order to economize the sequestration process we need to maximize injectivity per well. Rose Run formation has enough permeability required for injectivity. Containment is how long and how effectively CO_2 can be stored in the formation, as Rose Run formation Is rich in glauconite & other Ca & Mg minerals, so it can effectively trap CO_2 through mineral trapping for millions of years.[5.3]

5.4 Physical Properties of CO_2

At normal standard conditions CO_2 is a gas with density of 1.872kg/m3. Critical point for CO_2 is Tc=31.1°C and Pc=7.38 MPa(1070 psia). For temperature & pressure above the critical point, CO_2 is a supercritical fluid, means it will have its density characteristics like that of liquids & volume like gas. Both temperature & pressure increase with depth, but have opposite effect on CO_2 density. As temperature increases, density of CO_2 decrease & it increases with increases in pressure. In subsurface pressure changes about 10MPa/Km, and temperature changes by 25°C. So when injected at normal conditions CO_2 reaches it's critical point at about 700m. Figure 27 shows the phase behavior of CO_2.
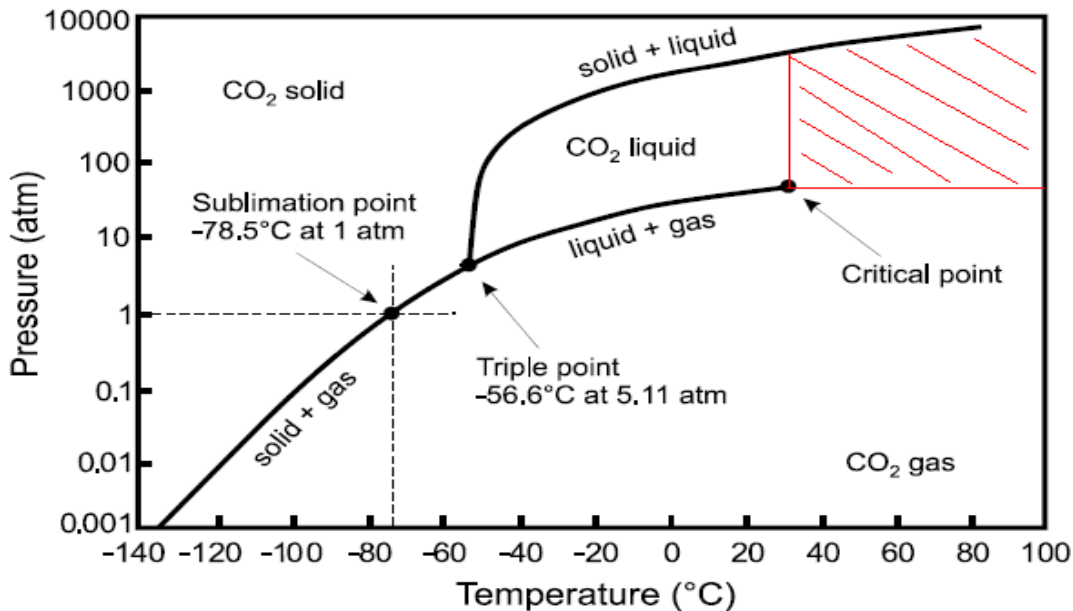
Figure 27: Phase behavior of CO_2

The critical temperature and pressure for CO_2 are $31^{\circ}C$ ($88^{\circ}F$) and 7.38 MPA (1070 psia). Whereas, reservoir pressure and temperatures are encountered between a range of 500-3000 psia and $68^{\circ} - 174^{\circ}$ F, so from the phase behavior of CO_2 it can be seen that CO_2 in most of the reservoir will fall in the critical region.

Also reservoir pressure and temperature are a function of depth. As has been mentioned before, the pressure gradient in Rose Run is 0.41-0.46psia/ft. and temperature gradient is around 1-1.2°F/ft.

So we see that at a depth of around 700m (2297 ft), CO_2 will reach at its critical phase.

P= 14.7+0.43*depth   (3)

T=61+1.1* depth   (4)

So it is better to store CO2 in very deep reservoirs where CO_2 meets the supercritical stage and has high molar density.

5.5 CO_2 Migration Behavior with the Pore Fluid

When CO_2 is injected into geological formation, it displaces the pore fluid there. Displacement can be miscible or immiscible depending on the chemical composition of CO_2, temperature and pressure. CO_2 and water are immiscible. Oil and CO_2 may or may not be miscible, depending on the composition of the oil and the formation pressure. CO_2 and natural gas are miscible. When the fluids are miscible, the CO_2 eventually displaces nearly the entire original fluid. Injection of an immiscible fluid bypasses some fraction of the pore space, trapping some of the original fluid. When EOR is performed using CO_2, miscible displacement is preferred, though oil can also be recovered by immiscible displacement.

5.6 Trapping Mechanism

Carbon dioxide is trapped in the formation by mainly four trapping mechanisms.

5.6.1 Hydrodynamic trapping

This is the temporary mechanism of CO_2 trapping, but is necessary for starting other mechanisms. Once injected, the supercriticalCO_2can be more buoyant than other liquids that might be present in the pore space. The CO_2 will therefore percolate up through the porous rocks until it reaches the top of the formation where it meets (and is trapped by) an impermeable layer of cap-rock. With a man-made CO_2 storage site, the wells that were drilled for injection through the cap-rock would be sealed with solid physical plugs made of steel and cement, a method which is already used extensively by the natural gas storage industry.

5.6.2 CO_2 residual trapping

This phase of trapping happens very quickly as the porous rock acts like a tight, rigid sponge. As the supercritical CO_2 is injected into the formation it displaces fluid as it moves through the porous rock. As the CO_2 continues to move, fluid again replaces it, but some of the CO_2 will be left behind as disconnected - or residual - droplets in the pore spaces which are immobile. This is often how the oil was held for millions of years.

5.6.3 Solubility trapping

Carbon dioxide dissolves in other fluids in its gaseous and supercritical state. This phase in the trapping process involves the CO_2 dissolving into the salt water (or brine) already present in the porous rock. Just as a bottle of fizzy water is actually slightly heavier than the same bottle filled with still water, so this salt water containing CO_2 is denser than the surrounding fluids and so will sink to the bottom of the rock formation over time, trapping the CO_2 even more securely.

5.6.4 Mineral trapping

The final phase of trapping results from the fact that when CO_2 dissolves in water it forms a weak carbonic acid. Over a long time, however, this weak acid can react with the minerals in the surrounding rock to form solid carbonate minerals. This process, when it takes place naturally, is very slow, but it effectively binds CO_2 to the rock.

Some of the basic Reactions involved in mineral trapping are as follows;

The most basic chemical reactions that lead to solubility trapping and mineral carbonation are [5.4]

$$CO_2(gaseous) \quad\longleftrightarrow\quad CO_2(aqueous) \tag{5}$$

$$CO_2(aqueous) + H_2O \quad\longleftrightarrow\quad H_2CO_3(aqueous) \tag{6}$$

Solubility trapping

$$H_2CO_3(aqueous) + OH^- \quad\longleftrightarrow\quad HCO_3^-(aqueous) + H_2O \tag{7}$$

Ionic trapping

$$HCO_3^-(aqueous) + OH^- \quad\longleftrightarrow\quad CO_3^{2-}(aqueous) + H_2O \tag{8}$$

$$CO_3^{2-}(aqueous) + Ca^{2+} \quad\longleftrightarrow\quad CaCO_3(solid) \tag{9}$$

$$CO_3^{2-}(aqueous) + Mg^{2+} \quad\longleftrightarrow\quad MgCO_3(solid) \tag{10}$$

$$Ca^{++} + Mg^{++} + CO_3{}^{2-} \quad\longleftrightarrow\quad CaMg(CO_3)_2 \text{ (dolomite)} \tag{11}$$

$$Fe^{++} + CO_3{}^{2-} \quad\longleftrightarrow\quad FeCO_3 \text{ (siderite)} \tag{12}$$

$$Mg^{++} + CO_3{}^{2-} \quad\longleftrightarrow\quad MgCO_3 \text{ (magnesite)} \tag{13}$$
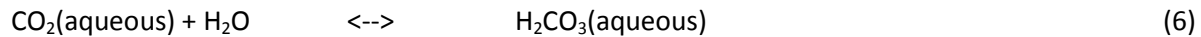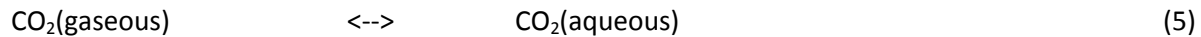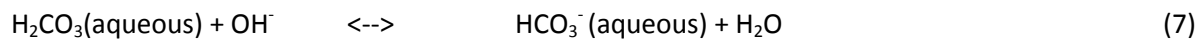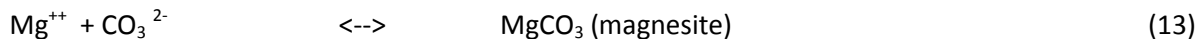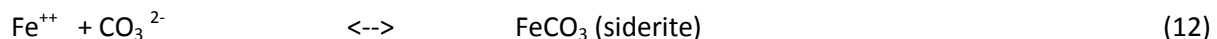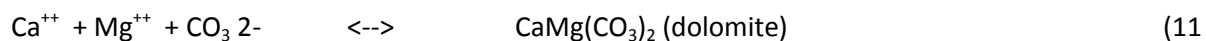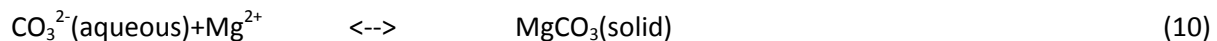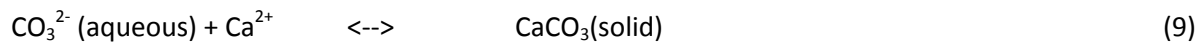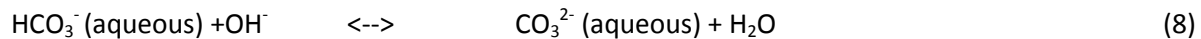
Mineral trapping

As we can see CO_2 forms carbonic acid, so pH decreases with the addition of CO_2. The pH of the system affects the reaction rate and species precipitated. In a closed system dissolved carbon dioxide, $CO_2(aq)$ and H2CO3 (carbonic acid) dominate at low pH, HCO_3^- (bicarbonate) dominates at mid pH, and CO_3^{2-} (carbonate) concentration increases at high pH. The solubility of carbonate also increases as the pH decreases. Thus, aqueous-phase equilibrium with $CO_2(g)$ promotes carbonate precipitation under basic conditions, while acidic conditions favor carbonate dissolution. Therefore, to favor the precipitation of

mineral carbonates, the pH must be basic. Thus pH is an important factor which controls the mineral trapping (temp. and pressure has minimal effects on mineralization).

Basic environments at high pH condition, pH= 11, provide an abundant supply of OH^-(aq), that leads to the formation of HCO_3^- and CO_3^{2-} and finally the formation of $CaCO_3$. The formation of calcite is expected to slow, once the OH^-(aq) is consumed. So it is concluded that in order to fasten the process we need to increase the Ph of the system [5.4].

5.7 Forced Mineral Trapping

Forced mineral trapping is the technique in which pH of the system is increased by introducing alkalinity in the system. In the U.S., hundreds of millions of tons of construction/demolition (C&D) waste are generated per year (LUND, 1993). Over 60% of the mass content of typical demolition debris is concrete (LUND, 1993). Lack of established markets and recycling facilities results in much of this material being land filled in many parts of the country. Because the principal constituent in concrete is portlandite [$Ca(OH_2)$], C&D waste represents a potentially large source of alkalinity. Rain or irrigation water reacting with crushed concrete would provide a source of $Ca(OH)_2$ for use in conditioning shallow terrestrial or deep geologic reservoir pore water to enhance formation of carbonate minerals. So forced mineral trapping can be applied w/o even adding ay additional cost to sequestration.

Figure 28 below shows the contribution of different trapping mechanisms involved in sequestration & also the time scale for each mechanism after injection of CO_2 in case of natural trapping mechanism.[5.5] Figure 29 shows contribution of trapping mechanisms after implication of forced mineral trapping. It can be seen that in forced mineral trapping, mineral trapping contributes more than 50% of trapping, and also time, when mineral trapping starts, is decreased 20 times as compared to natural mineral trapping. So forced mineral trapping is very promising technique for sequestering carbon dioxide in Rose Run formation for long time.
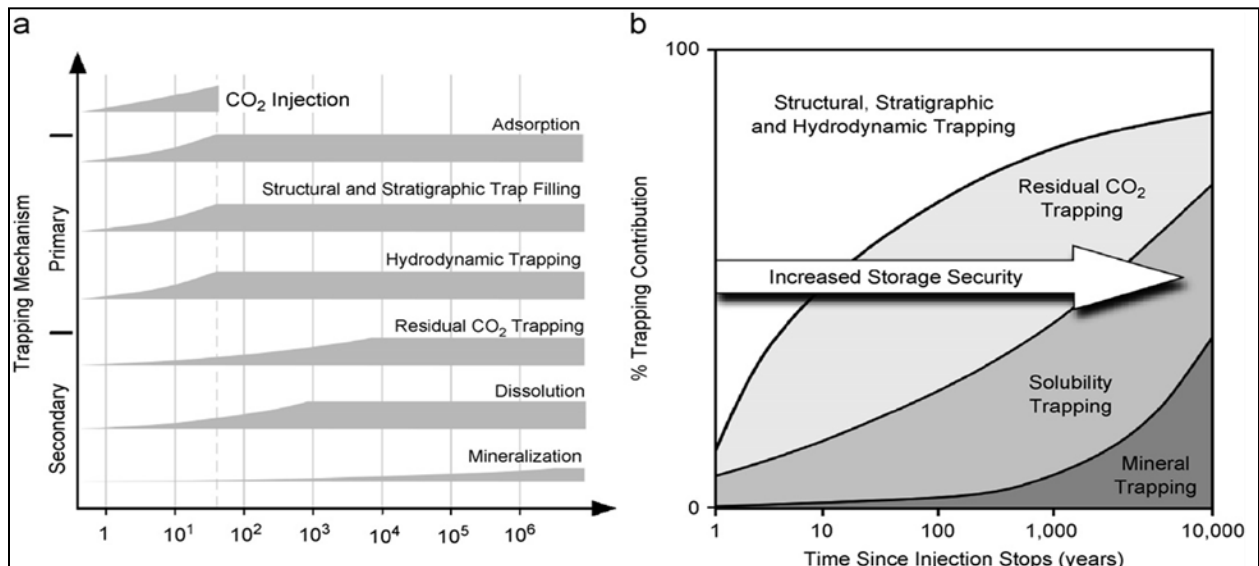
Figure 28: Differences between various CO_2 Trapping mechanisms in geological media: (a) operating timeframe, and (b) contribution to storage security

Figure 29: Mineral Trapping behavior
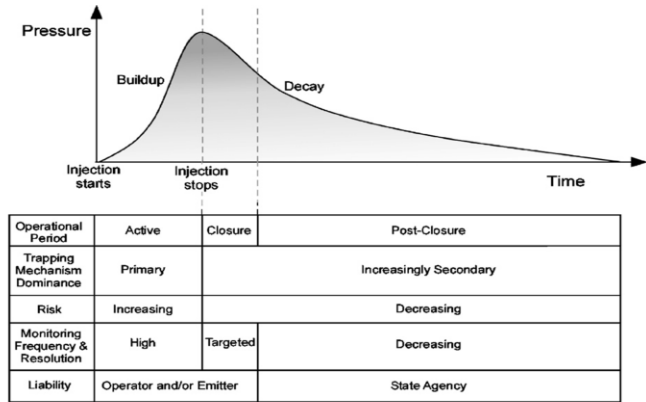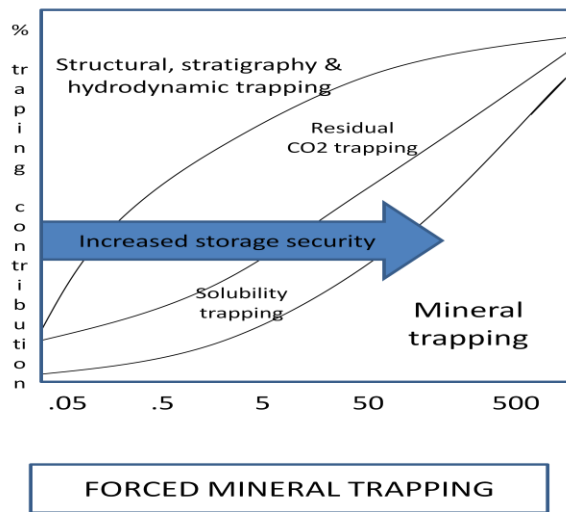
The figure on the right hand side of figure 29 shows the relationship between pressure behavior & operational phases. We can see that after CO_2 injection is stopped, & secondary trapping comes into picture, risks associated with sequestration become lessen. Also, need for monitoring decreases after starting of secondary mechanisms.

Some facts and assumptions regarding forced mineral trapping include that most of the CO_2 will remain in free phase, it's only after hundreds of years and mineral trapping dominates all other trapping mechanisms. Also, porosity & permeability will be changed once the injection starts, and it will affect the capacity of formation. In case of sequestration within EOR, $Ca(OH)_2$ will be injected after completion of enhanced oil recovery.

5.8 Technical Aspects and Challenges in Sequestration

Most important challenge in CO_2 sequestration is to avoid the leakage. When CO_2 is injected in deep formations, because of buoyant forces, it tries to escape the reservoir. Also it is lighter than water(contained in the reservoir) , so it has tendency to escape through the migration paths which are made by Hydrocarbons. CO_2 is non wetting phase in the reservoir, so it experience large capillary forces. These forces help CO_2 sequestering in the reservoir, as they are much larger than the buoyant forces. Good possibility of leakage is there, if buoyant forces overcome these capillary forces somehow.

Sealing capacity of the cap rock for a hydrocarbon-water system is sufficient to prevent the injected CO_2 from leaking. Sealing capacity is a measure of the breakthrough pressure. Capillary pressure determines the breakthrough pressure of the cap rock. Also capillary pressure of the interconnected pore channel depends upon the interfacial tension as shown below:

$$Pc=(2\sigma/Rp)* \cos \theta \tag{14}$$

Where   Pc= capillary pressure
                σ=interfacial tension between the non-wetting (gas or oil) & the wetting phase(water)
                Rp=radius of pore throat
                Θ= contact angle

So interfacial tension plays important role in avoiding the leakage of CO_2 back in the atmosphere, also the breakthrough pressure of the cap rock should also be calculated.

5.9 Modeling Of Sequestration of CO_2 in Rose Run

As has been discussed in the capture section, the amount of CO_2 from the plant is around 3.4Mton/year. We are capturing near about 90% of total emission (3.06Mton/year). It can be converted into field units as follows:

1lbs of CO_2 = 1/44   lb mol of CO_2

 1 lb mol of CO_2= 379.1SCF OF CO_2

3.06 Million ton= 3.06 * 10^9 Kg = 6.74 * 10^9 lbs

So 3.06 million ton of CO_2 = 5.8 * 10^{10} SCF of CO_2

So 5.8 * 10^{10} SCF of CO_2 amount of CO2 is needed to sequester per year.

A model has been established using GEM for finding out how many no. of wells are required to inject all of CO_2 in the formation. Reservoir has been discretized in 11*11 square blocks, and dimension of each side of block is 2000ft. Properties of the formation which are used while making the model are as summarized in the table 11 below.

Table 11: Ground rock properties of formation

	Depth (ft^3)	Thickness (ft)	Permeability (mD)		Porosity (%)		Pressure gradient	Formation Fluid Temperature (1F/100ft)
			Regional	Site	Regional	Site		
Rose Run sandstone	2500-11,000	50-200	0.01-198	N/A	2-2.5	N/A	0.41-0.46	1-1.2
Underlying Shawville (PA)	7550	75-150	N/A	13-86	N/A	8-14	0.43-0.46	1

Properties of the Rose Run sandstone (25miles away from the Shawville power plant location) where we are actually sequestering the CO_2 are assumed on the basis of above data and are as in the table 12 below.

Table 12: Rose Run assumed rock properties

	Depth(ft)	Thickness (ft/layer)	Permeability (mD)	Porosity (%)	Block Dimensions(ft2)	Initial Reservoir pressure (psia)
Rose Run sandstone	7000	30	15	2.5	2000*2000	3000

We are considering a time span of 30 years. That means 30 years of CO_2 emission from Shawville power plant will be sequestered. Reservoir has been assumed to me homogeneous with a permeability value of 15mD in each direction. Also whole reservoir has been considered to be consisting of one layer. Wells location has been considered as symmetric to each other, so injection rate in every well is same (all wells are identical). Figure 30 below shows the location of wells in the formation. A total of 5 wells have been used. All wells are injection wells. Figure 31 shows the cumulative injection and the rate of CO_2 injection.
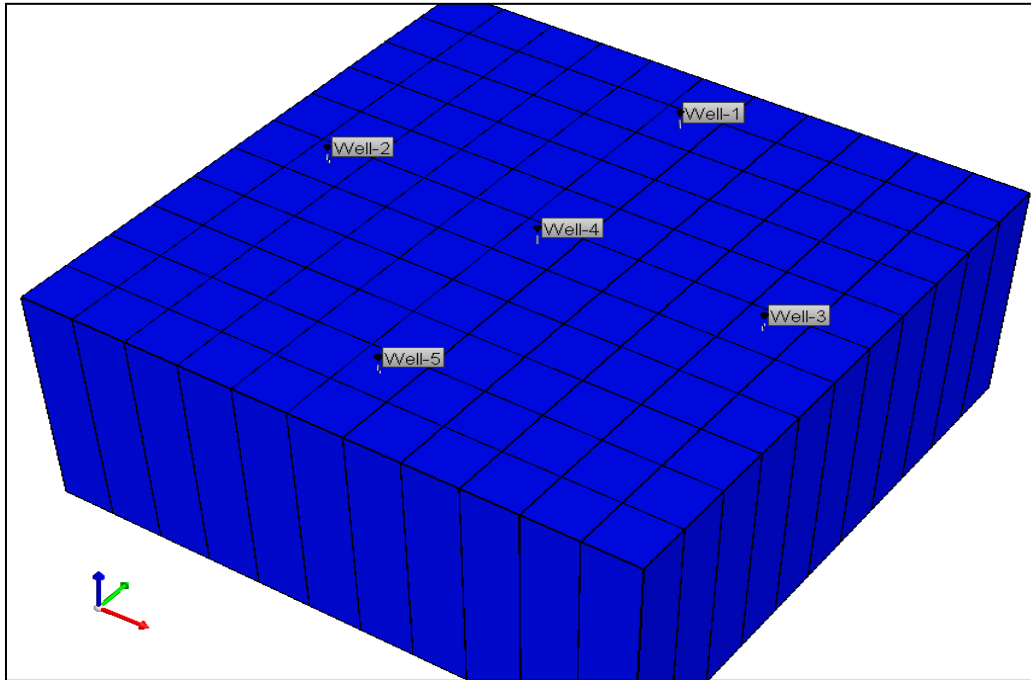
Figure 30: 3-D representation of the field
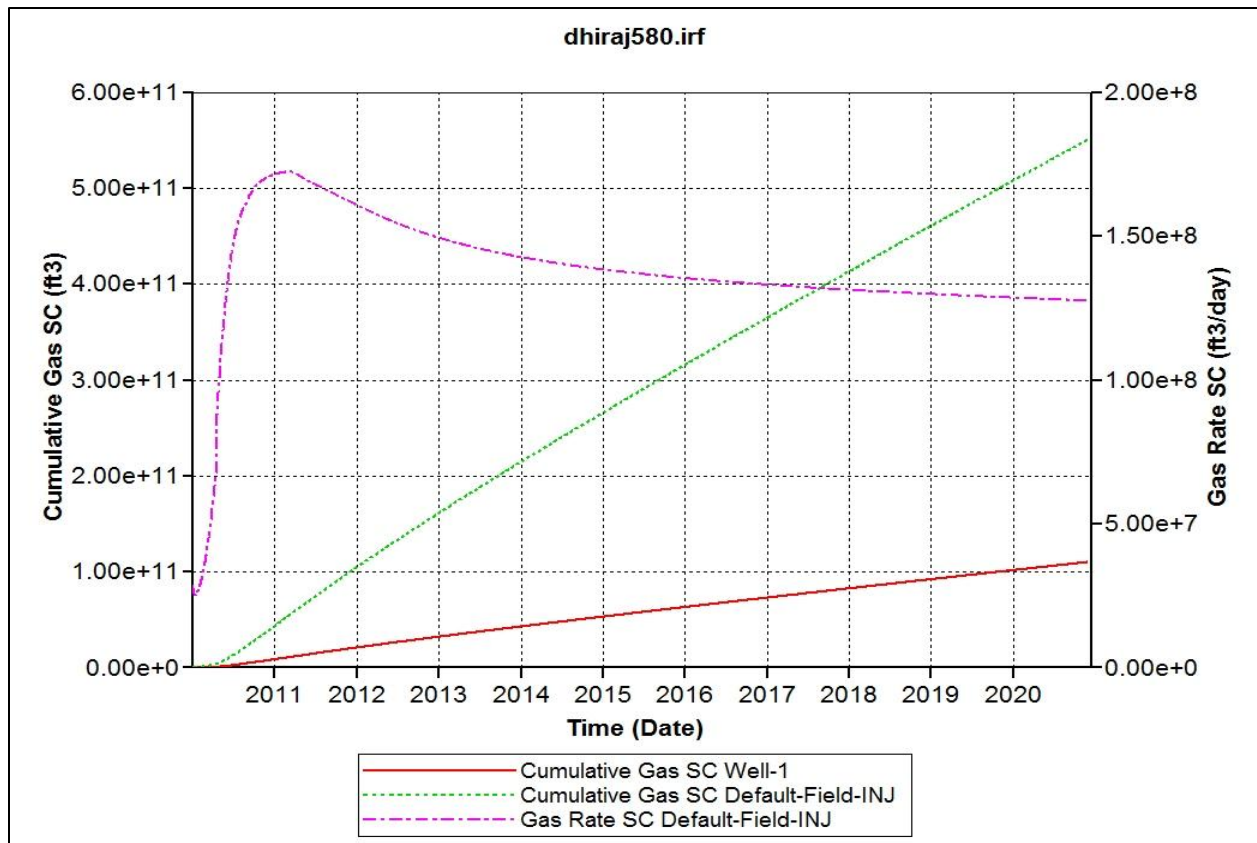
Figure 31: Cumulative and rate of CO_2 injection

5.10 Economic Analysis for Sequestration

Rose Run formation has lots of depleted oil and gas reservoirs, thereby in past a number of wells were drilled in the formation. So we are not drilling any new well, but we will use the wells already drilled for injecting the CO_2. Wells which are already drilled there are reworked so to make them suitable for injecting CO_2.

 As we are not producing anything(we don't have any production well) in this model so the only costs which are associated in the project are cost of capturing CO_2, cost of transportation cost of reworking on wells, O & M costs and costs related to monitoring. Only costs which are considered in the economic analysis of CCS are as in table 13.[6.6]

Table 13: Cost of reworking wells

VARIOUS COSTS	PER WELL PER YEAR ($)		TOTAL(MM$)
reworking on existing wells	181968.75(constant for 1 well)		-0.9098
operating & maintenance costs	111863.75/ well/year		-5.593
total			-6.5028

Costs of capture, transportation, and monitoring are considered in the project conclusions cost analysis.

The project shows that in simple cost analysis which will be compared for same conditions with CCS within EOR, the project is in loss of around $7 million. While the project operates for CCS within EOR, it will end up making profit while sequestering the same amount of CO_2.

Chapter 6: CO_2 Utilization for Enhanced Oil Recovery

6.1 Introduction

CO_2 is generated in the environment by natural sources and by anthropogenic sources. It is the main cause of global warming. In order to mitigate the concentration of CO_2 along with sequestration, it must be utilize in useful applications in industry. Currently CO_2 is used in fabric cleaning, fire extinguishers, in wine making & most importantly as working fluid in enhanced oil recovery. CO_2, when used in enhanced oil recovery process, it makes the sequestration of CO_2 more economically viable.

6.2 Enhanced Oil Recovery Using CO_2

Oil reservoirs when put on production, first produces because of their own pressure (primary recovery), after then water flooding is used (secondary processing). But only 30-40% of original oil in place can be recovered by these processes. Rest of the oil remain in the reservoir either because of its immobility or because it get stuck in low permeability zones, which are not accessed by water during secondary processing. So in order to recover that oil enhanced oil recovery is used.

There are lots of techniques available for EOR like thermal EOR, chemical EOR, microbially EOR, and CO2 EOR. In this project we are concerning CO_2-EOR in the Rose Run Formation (Coal Fex Field, Ohio). In CO_2-EOR , first CO_2 is injected in the reservoir, it displaces the oil in the reservoir, and the oil swells. After that oil is just needed to be pushed towards the production wells, which is done by water flooding.

6.3 Scope & Potential of CO_2-EOR in United States

CO_2-EOR projects accounted for 3.1% of total crude oil produced in USA in 1998. In 2005, oil production from CO_2 -EOR was approximately 237,000 bbls/day. The pie chart below in figure 32 shows the potential targets for CO_2-EOR in United States. Figure 33 shows the amount of oil recovered by CO_2-EOR in U.S. per year since 1985[6.1]. From the pie chart we can see there are vast reserves of oil are available which can be recovered by CO_2. So scope of CO_2 enhanced oil recovery is very bright in U.S.A.
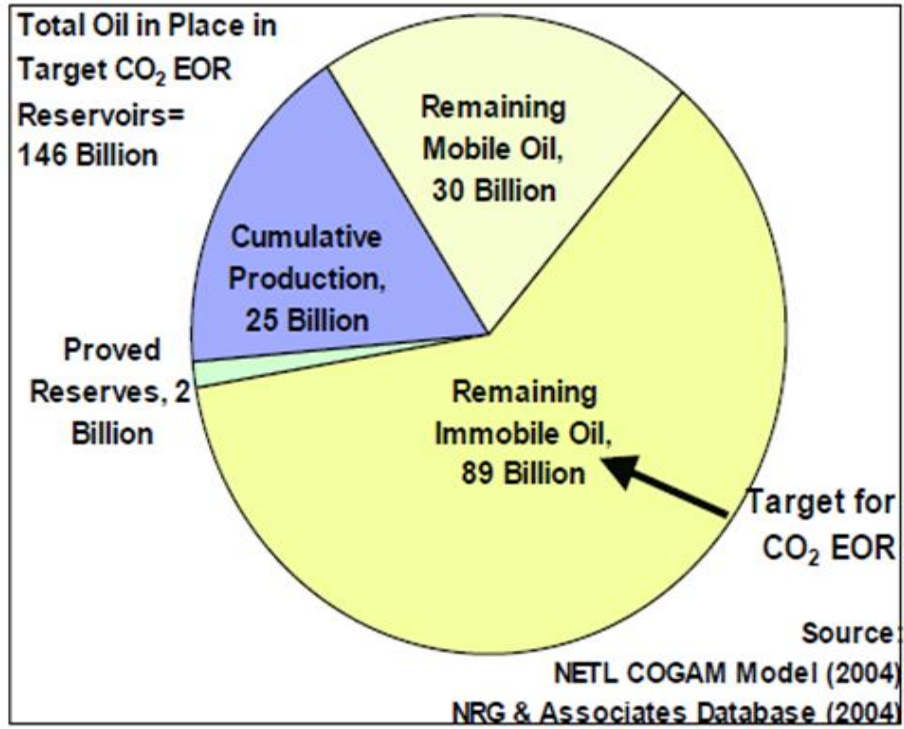
Figure 32: Potential Target for CO_2 EOR
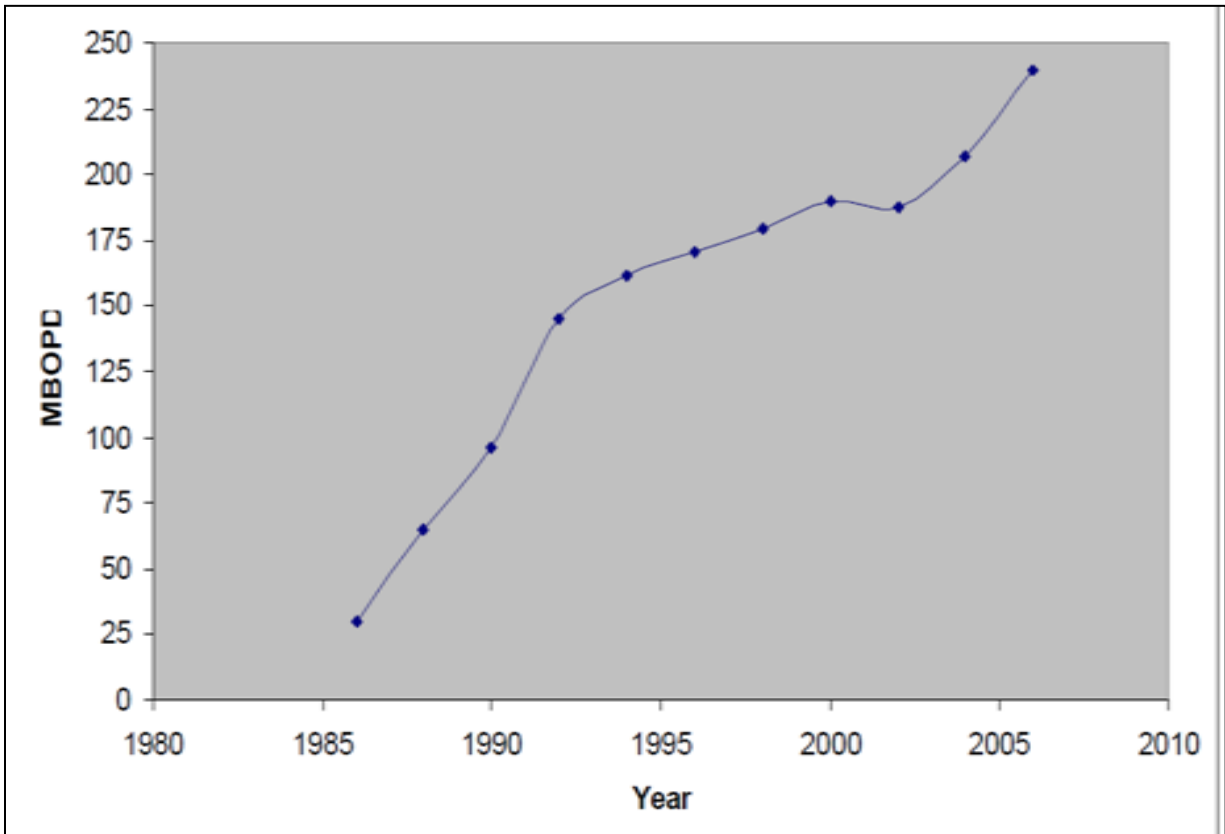
Figure 33: US Oil Production from CO_2 EOR Projects by Year

6.4 Technical Aspects of CO_2-EOR

When CO_2 is injected in the oil reservoir, it displaces the oil. As previously mentioned, CO_2 can be either miscible or immiscible with the oil. Miscibility depends upon the chemical composition of CO_2, composition of oil, temperature & pressure. Immiscible displacement of oil makes the EOR process complex.

Miscibility

Whether CO_2 will be miscible or immiscible can be found by long-tube experiment. Also the pressure at which CO_2 mixes with the oil immiscibly can be found.

The minimum pressure at which miscible displacement of oil occurs is known as Minimum Miscibility Pressure (MMP). So if we find that CO_2 will be immiscible with the oil, by increasing pressure of CO_2 injections we can make the displacement miscible and which will it be beneficial for EOR. In thel ong slim tube experiment, a reservoir sample is taken and CO_2 is injected at different pressures, & the MMP is found.[6.5]

In our project we are dealing with the Rose Run formation, in which oil is considered equivalent to black oil, so we will go with the assumption that miscible displacement of oil will take place.

Carbon dioxide achieves super critical state when injected in deep formations. In that case properties of gas and liquid phases become identical. At super critical conditions, fluids experience lower surface tension than liquids, which allows it to diffuse easily in the reservoir through small pore spaces. In super critical conditions fluids act as a liquid in terms of density (high density) and as a gas in terms of viscosity (low viscosity).

6.5 Reservoir Fluid & Formation Properties

Table 14 below summarizes the properties of reservoir fluid & formation, when the Rose Run reservoir (Coal Fex Field) was put on production in 1997[5.2].

Table 14: Rose Run Reservoir Fluid and Formation Properties

The specific gravity of the crude oil	0.827 corrected to 60^0 F
Initial pressure of the reservoir	1700psia ((in 2004) we are including pressure build up so we take Pi=3000psia for our model)
Water saturation	41.8
FVF	1.17-1.21RB/STB
Thickness	27ft(ten layers each of thickness 2.7ft)
Porosity	17.1%
Horizontal Permeability	1 mD
Vertical Permeability	0.1 mD
Compressibility of the rock	$4.0*10^{-4} psi^{-1}$
Viscosity Of The Oil	0.74cp
Drainage AREA	130ACRE

Based on the above data OOIP (original oil in place was calculated) as 2,207-2,282MSTB. Out of above OOIP, around 12.6% has been produced by 2002.

6.6 Process Description

In order to economize the sequestration of CO_2, sequestration can be done within enhanced oil recovery. Figure 34 below shows the flow diagram of CO_2-EOR with sequestration [6.1]
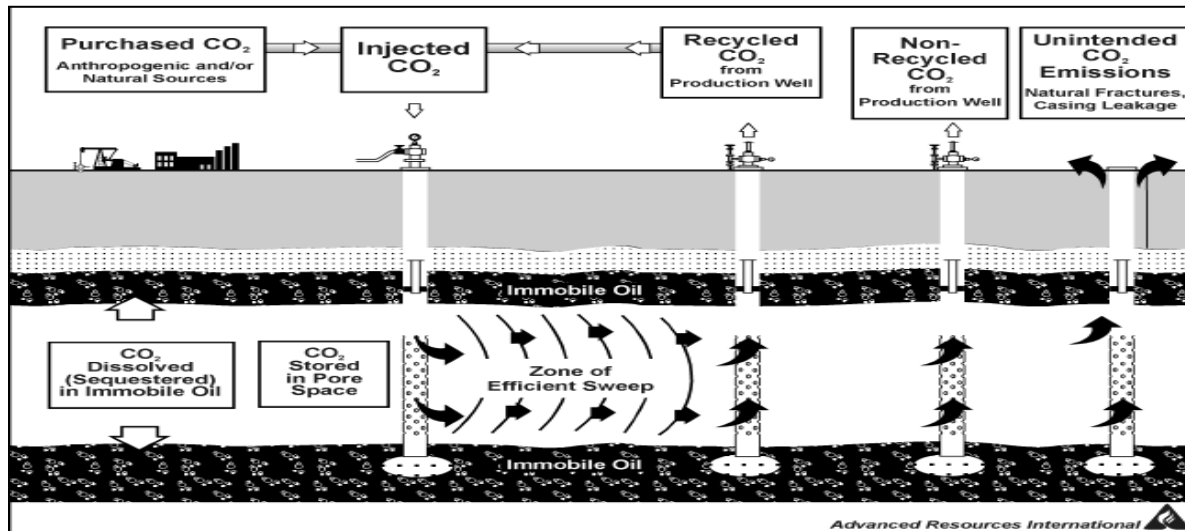
Figure 34: Sequestration of CO_2 within EOR

In general the above process can be explained in the following steps:

6.6.1 CO_2 injection & miscible displacement of oil:

CO_2 from the Shawville plant is transported to the reservoir site once is captured and transported from the plant through pipelines. Then through injection wells, it is injected in the reservoir. A number of wells were drilled in the Rose Run formation, so we can use already drilled wells for injecting CO_2. After injection, it mixes with the oil, and forms a binary mixture. CO_2 displaces oil either miscibly or immiscibly depending on the oil composition. Figure 35 below illustrates the behavior of a binary mixture below 120 of CO_2 and oil from the Wasson field, a large field in West Texas where CO_2-EOR is planned [6.2].
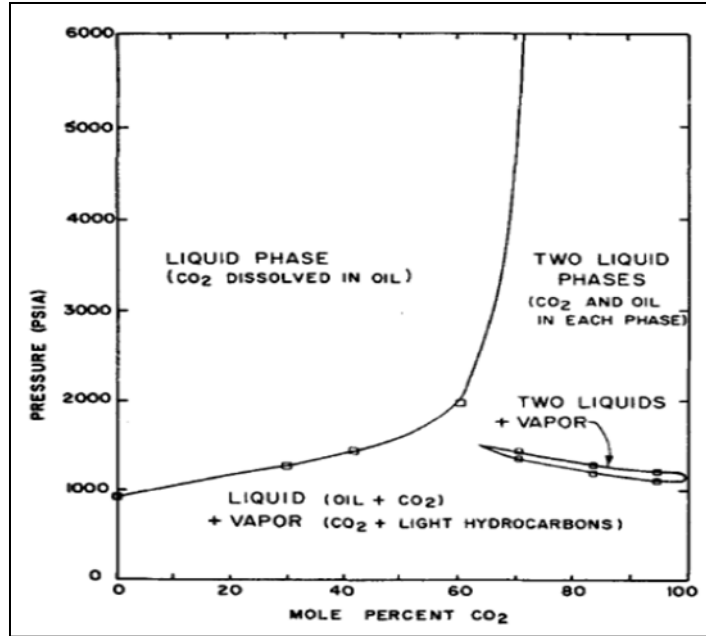
Figure 35: Binary mixture behavior of CO_2 and Oil at 120F

If we assume the Rose Run formation's properties are the same as the Wasson field, then we can come up with the range of CO_2 mole fraction for the miscible displacement of oil. We are considering the Rose Run formation at a 2500m depth. Applying the 10MPa/km pressure gradient, we see that at 2500m depth, CO_2 will be at a pressure of 25MPa when it is injected under normal conditions.

Now as 1 Megapascal is equivalent to 145.04 pound-force/square inch (psi), conversion equates 25MPa to 3625.93 psi. So from above figure 35 we can see that at 3625.934psi, we can handle CO_2 mole fraction from 0.00% to about 70% for the miscible displacement of oil by CO_2, when pumping CO_2 at normal conditions.

When CO_2 is injected in to the oil reservoir, the miscible mixing of oil and CO_2 leads to oil swelling and lowers the oil viscosity, allowing oil to flow to the production wells. The factor which characterize the mobile behavior of any phase is:

$$(k/\mu) \tag{15}$$

Where k= permeability and μ= viscosity of phase.

As μ decreases when CO_2 is mixed with oil, mobility increases.

6.6.2 Production & Wag (water alternating gas)

When oil is mobilized by CO_2 and freed from its residual saturation state, it needs to be pushed or pulled to the production well. For that purpose water driver are used to alternate the CO_2 injection. This process is known as water alternating gas (WAG).[6.1] Figure 36 shows how WAG works in the production of oil [6.1]. In figure 34 the zone of efficient sweep is the zone where WAG takes place. So

water pushes the oil to the production wells, and from the production wells, a mixture of oil, water & gas comes out.

Also CO_2 can be leaked through wells which have been drilled in the past or from the natural fractures, so in order to avoid that CO_2 mixing in environment either we plug the preexisting wells or we try to capture that unintended CO_2 by continuous monitoring after injection.
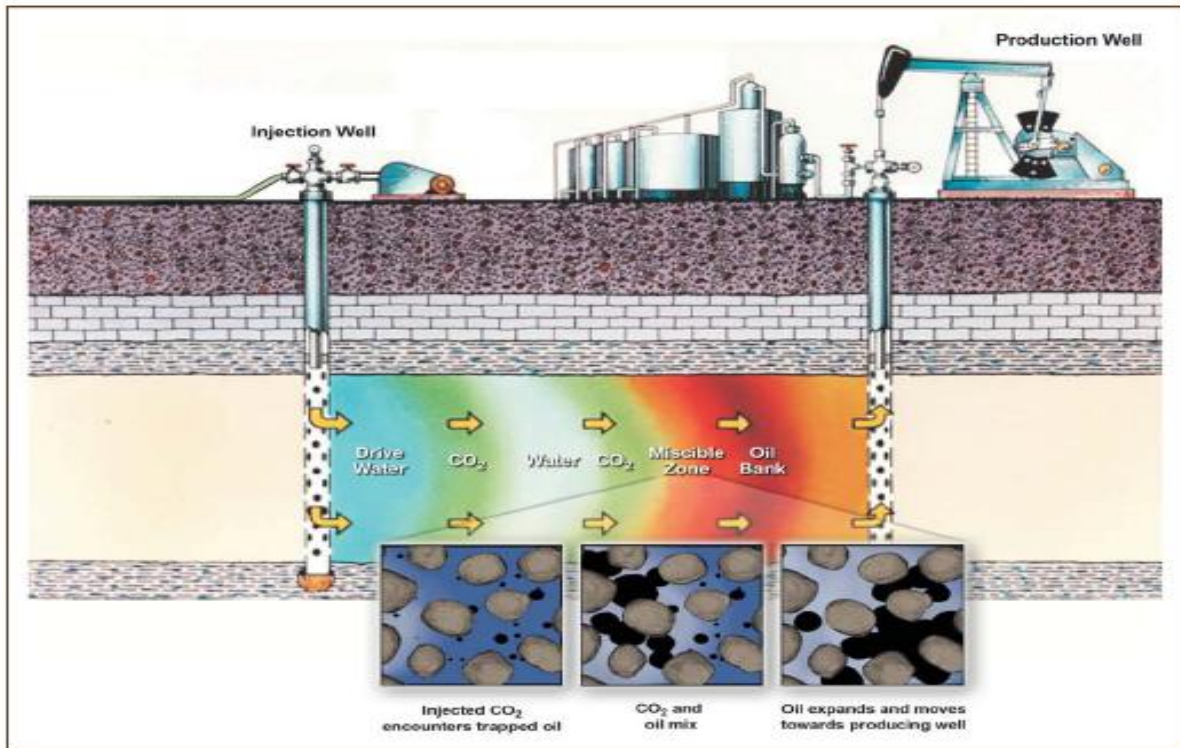
Figure 36: WAG (water alternating mechanism)

6.6.3 Recycling

After production, a mixture of oil, water and CO_2 is sent to the separator, and when feasible, the mixture is processed and recycled with the pure CO_2 from power plant and is reinjected down the injection wells. The treatment of CO_2 for recycling can be done by using amine (DEA) adsorption processes, extractive distillation techniques or membrane separation. All these processes are electricity intensive. In our project, we see that we do not produce much CO_2, so recycling of CO_2 is not going to be too expensive; however we are considering the recycling of CO_2 as well.

6.6.4 Sequestration

Some of the injected CO_2 dissolves into the immobile oil resources and remains trapped in the reservoir. Carbon dioxide remains in the reservoir by primary trapping mechanisms like structural trapping and residual CO_2 trapping. After EOR is completed and the reservoir is declared dead, alkalinity is introduced in to the formation by injection of $Ca(OH)_2$ in order to enhance forced mineral trapping. That is the advantage of doing EOR; we make profit by selling CO_2 and also we sequester CO_2 at the same time.

6.7 Modeling of CO$_2$-EOR

A model has been established for CO$_2$-EOR in coal-Fex Field, using CMG simulator. Figure 37 below shows the basic reservoir and well locations in the reservoir.
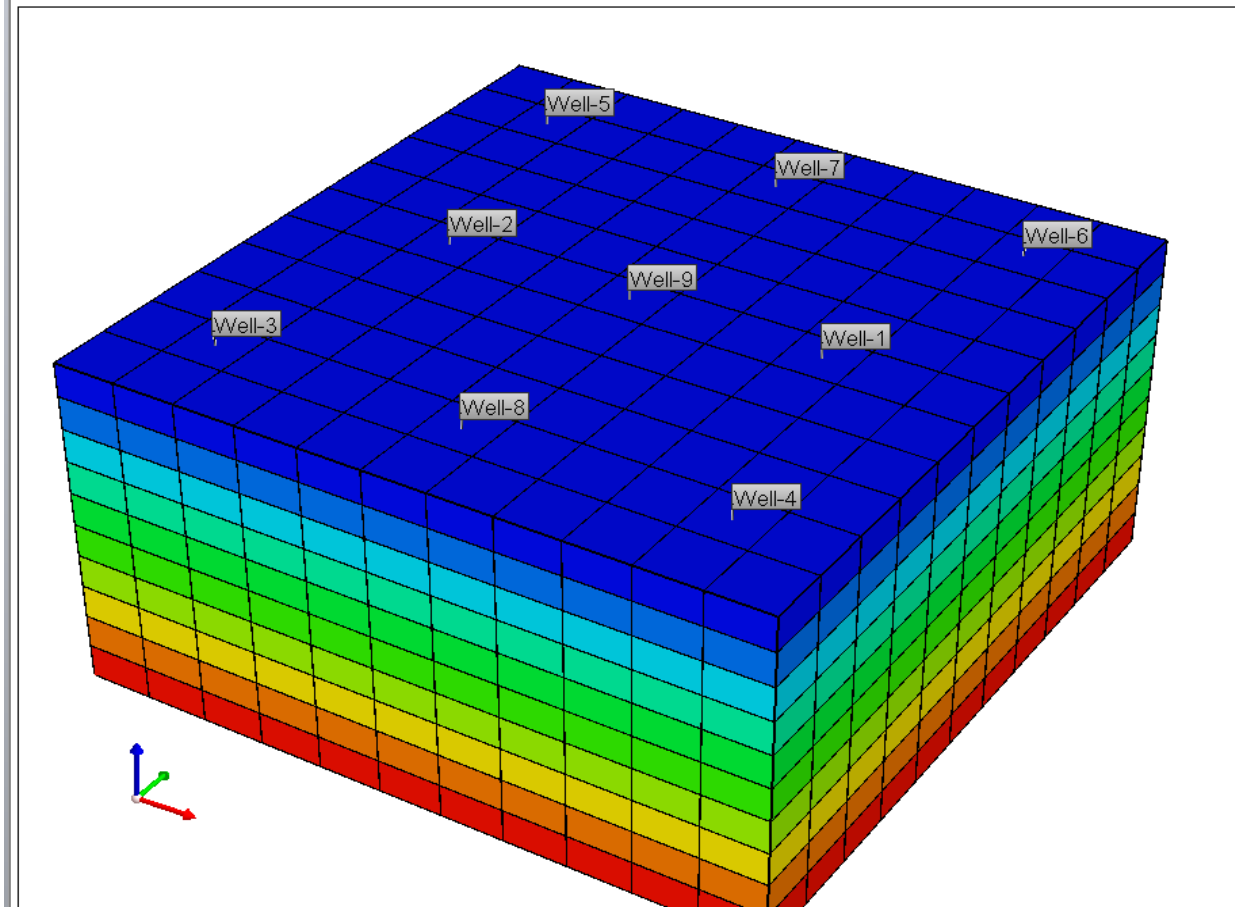
Figure 37: 3-D representation of the field

A total of ten layers have been considered and the thickness of each layer is 2.7 ft.

EOR will be done for the first ten years. After ten years, only injection of CO$_2$ will occur, and we will shut down all the production wells. Wells 1, 2, 7, 8, 9 are injection wells. Wells 3, 4, 5, 6 are production wells during the first ten years.

Oil is produced for the first ten years, and then wells 3, 4, 5, 6 are converted into injection wells. Also, as in ten years, well block pressure in wells 1, 2, 7, 8, 9 will increase, so we cannot continue injection in these wells. Otherwise it will cause fractures in the formation. So these wells will shut down after ten years. After ten years, we switch to injection in wells 3, 4, 5, 6 which have been converted into injection wells.

6.8 Results

The simulation model was run for ten years to find out the amount of oil produced. After that production of oil has stopped and the production wells are converted into injection wells. The injection wells used for first ten years also shut down after EOR processes.

All models are run for 30 years, from 2011 to 2040. As CO_2 is injected into the reservoir, pressures within the reservoir increase and CO_2 tends to fill the pore spaces and displace the oil forward towards production zones. The production wells will sense an increase in production rates due to increases in pressure gradients between the sweeping and residual fluids. Figure 38 below shows the cumulative injection of CO_2 over a period of ten years during EOR and figure 39 shows the cumulative injection of CO_2 over a period of 30 years. The cumulative amount of CO_2 injected from 1 well in ten years is $1.1022*10^{11}$ scf, and the cumulative amount from all five wells is $5.511*10^{11}$ scf.
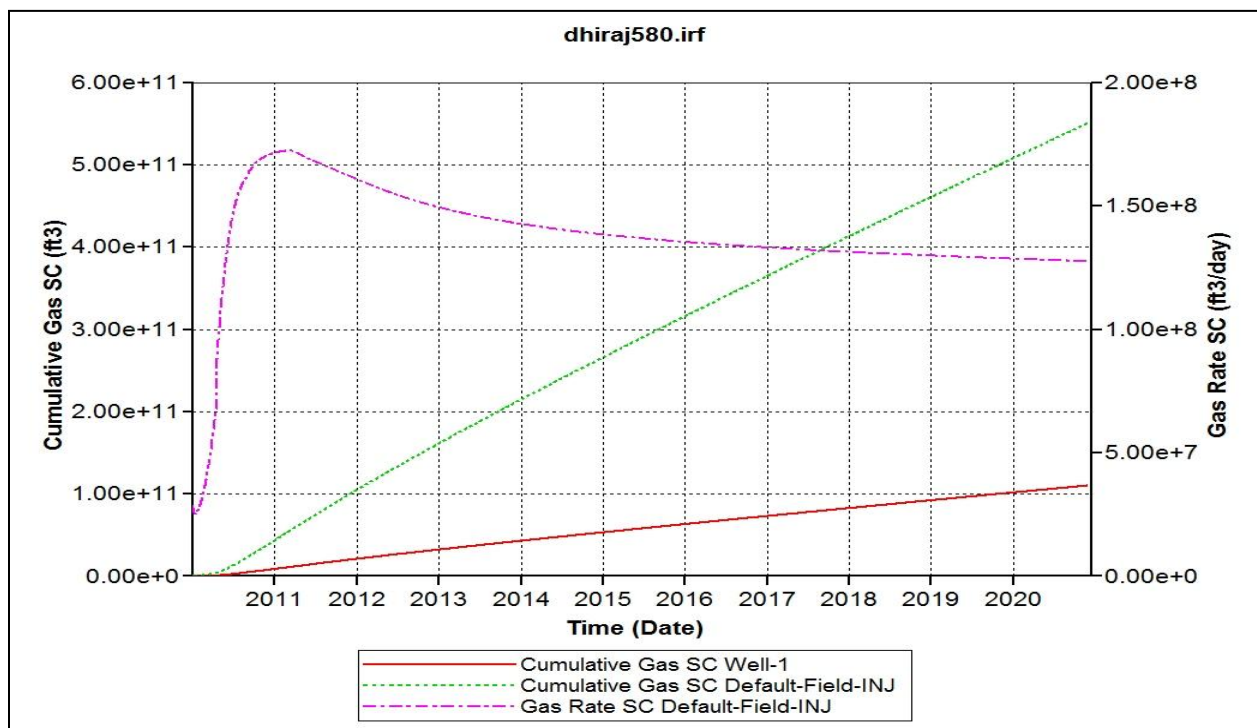
Figure 38: Cumulative injection of CO_2 during 10 year EOR period
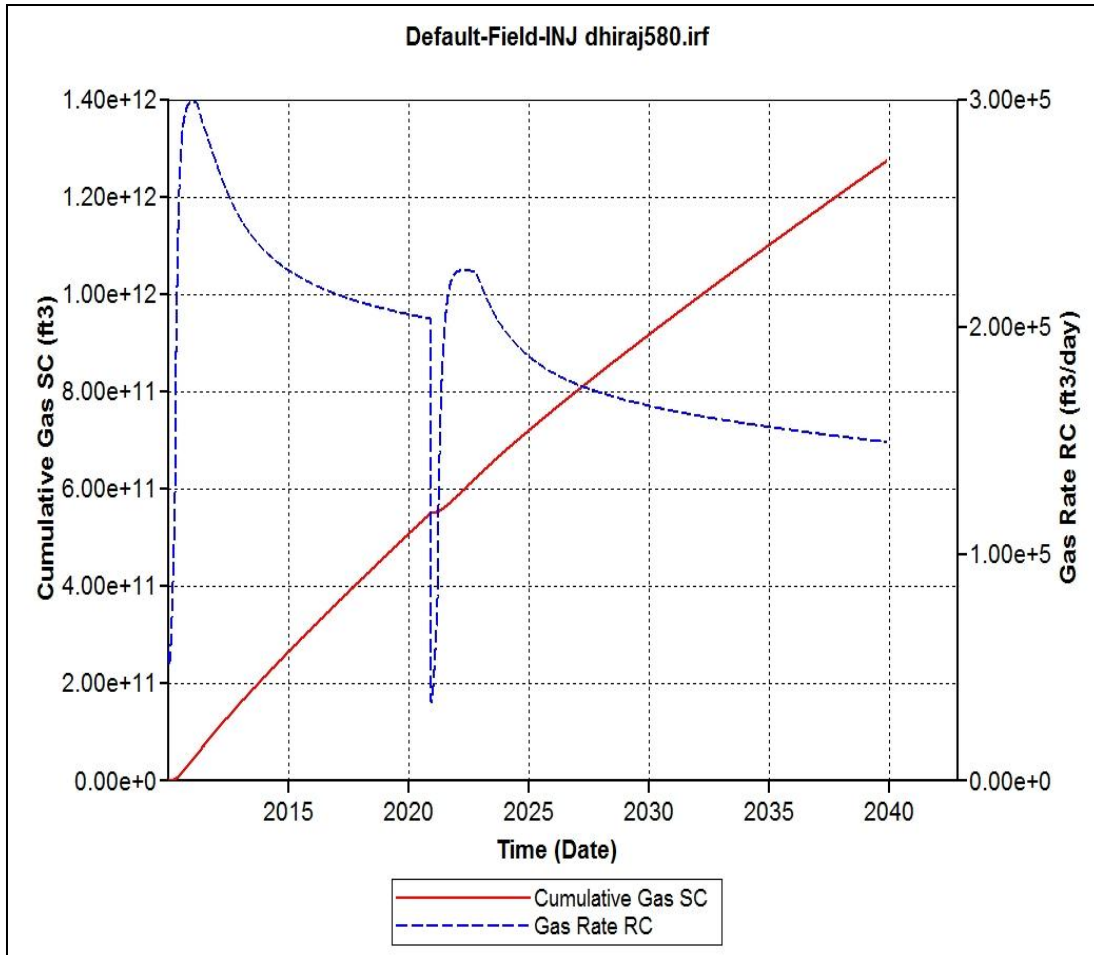
Figure 39: profile of CO$_2$ injection over 30 years

Cumulative CO$_2$ injection from the field using the model above in 30 years = 1.274*10^{12}SCF   (15)

We see that pressure in the well block reaches approx. 11,000 psia, so in order to avoid the fracturing of the formation; we stop the injection after 30 years. Rates of CO$_2$ injection increase at first and then decrease as well block pressure is low. Figure 40 below shows the field cumulative oil production, cumulative oil production from 1 well and the rate of production of oil. The amount of oil produced in these ten years is 406614 barrels.   As previously mentioned OOIP of the field is approximately 2250 MSTB, so we produce about 18% of OOIP. CO$_2$ and water will also be produced along with the oil, however we see that amount of water is almost negligible (1-2bbl/d), so it is not consider in the cost of separation of oil from water. The amount of CO$_2$ produced is very low. We will install a CO$_2$ recycling plant to recycle whatever the amount of CO$_2$ is produced. Figures 41 and 42 show profiles of CO$_2$ and H$_2$O production over ten years. The amount of water and oil produced after 10 years is 6895.67bbl and 7.26 million bbl, respectively.
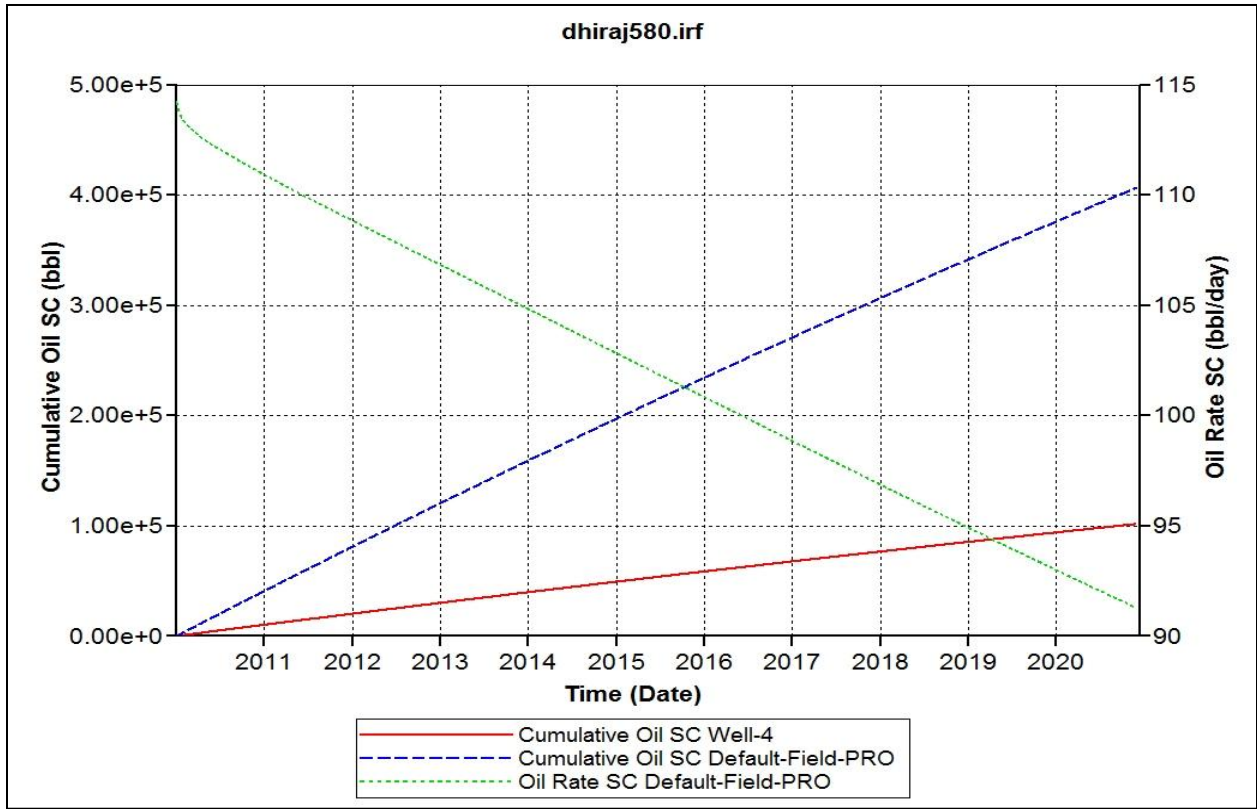
Figure 40: Cumulative oil production from well 1
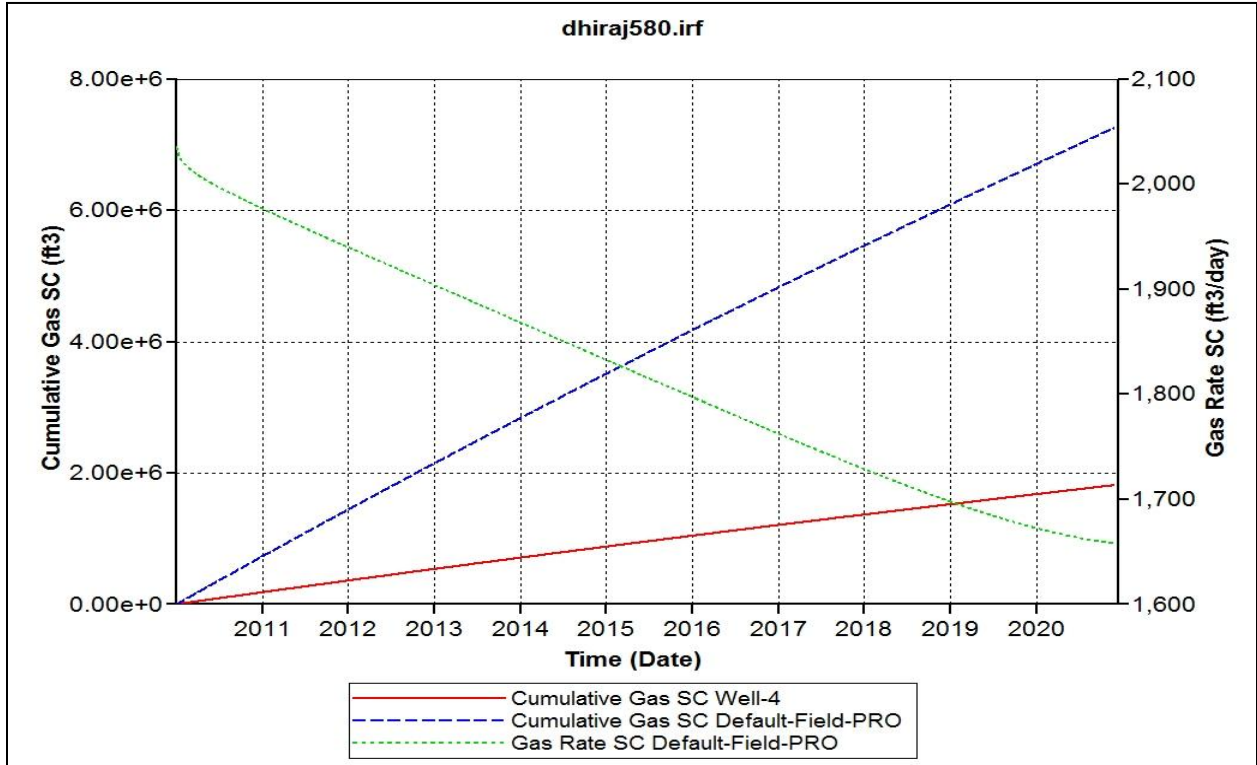
Figure 41: Profile of CO$_2$ production
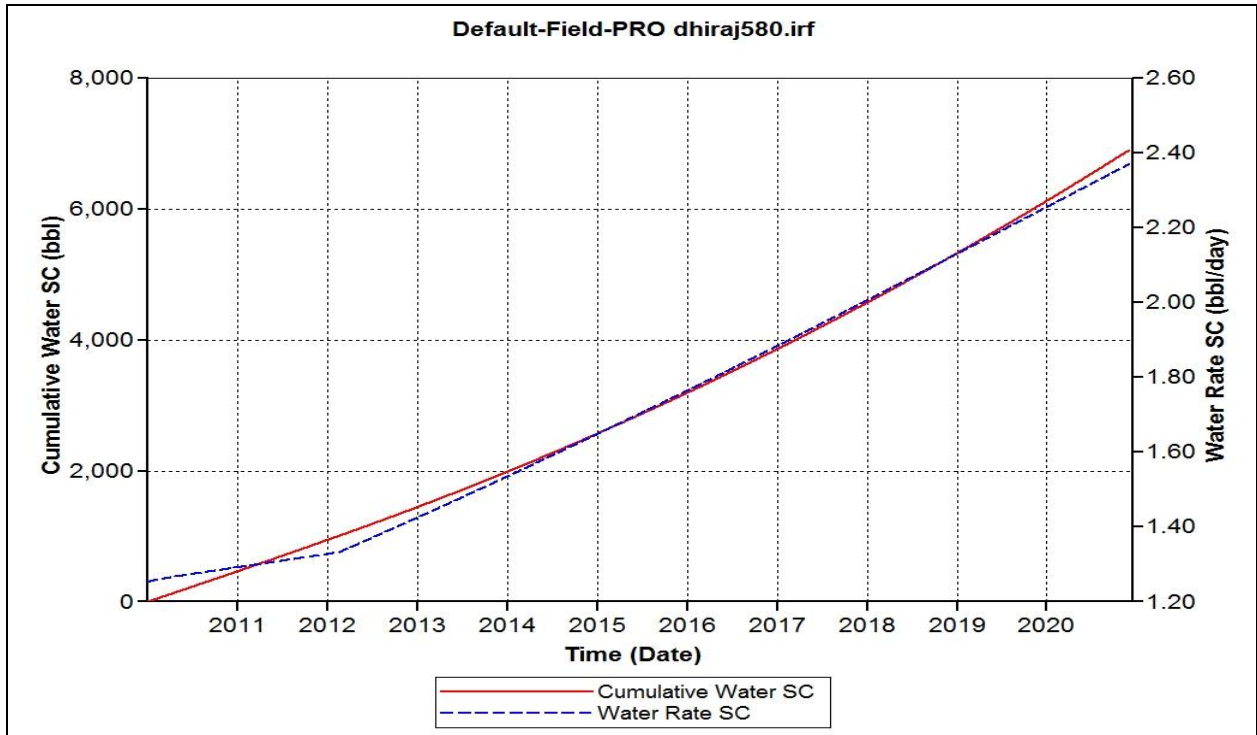
Figure 42: Profile of H_2O production

We also need to keep in mind the pressure of the formation should not exceed 12,000 psia (which we have assumed as fracture pressure of the formation). Figures 43 and 44 below show the pressure profiles of the formation after 10 years and 30 years, respectively.
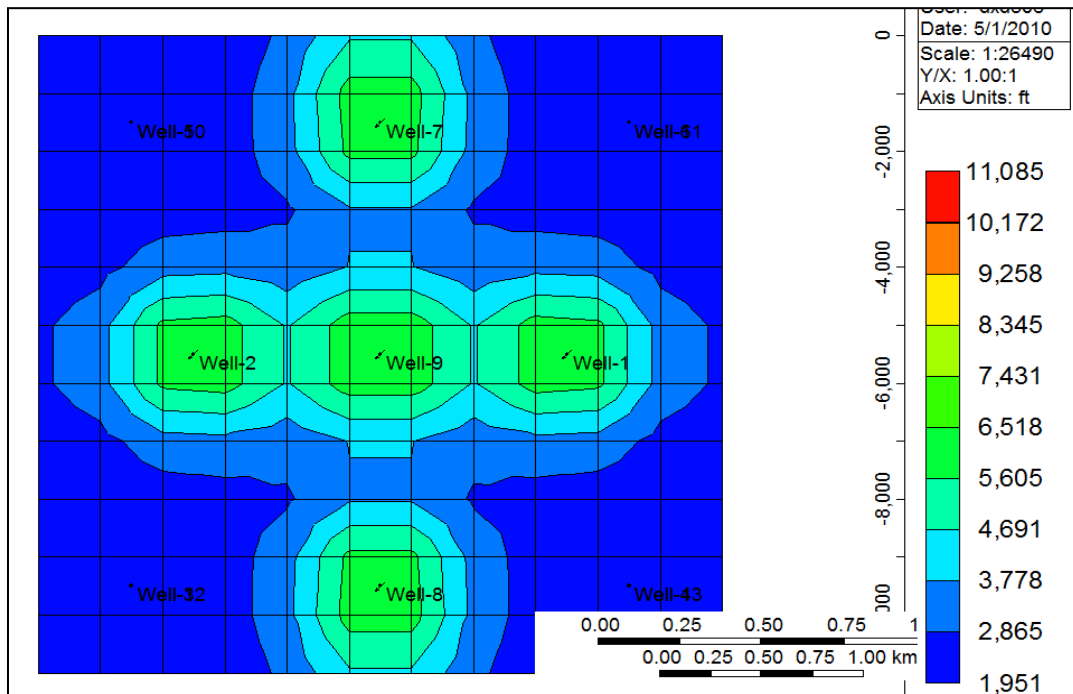
Figure 43: Pressure profile after 10 years of operation

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We see that after 10 years, pressure is at its maximum in well blocks between 9900-10000psia. So in order to avoid further increases in pressure we, shut down in all wells and then new injection wells (production wells which have been converted into injection wells) are used.
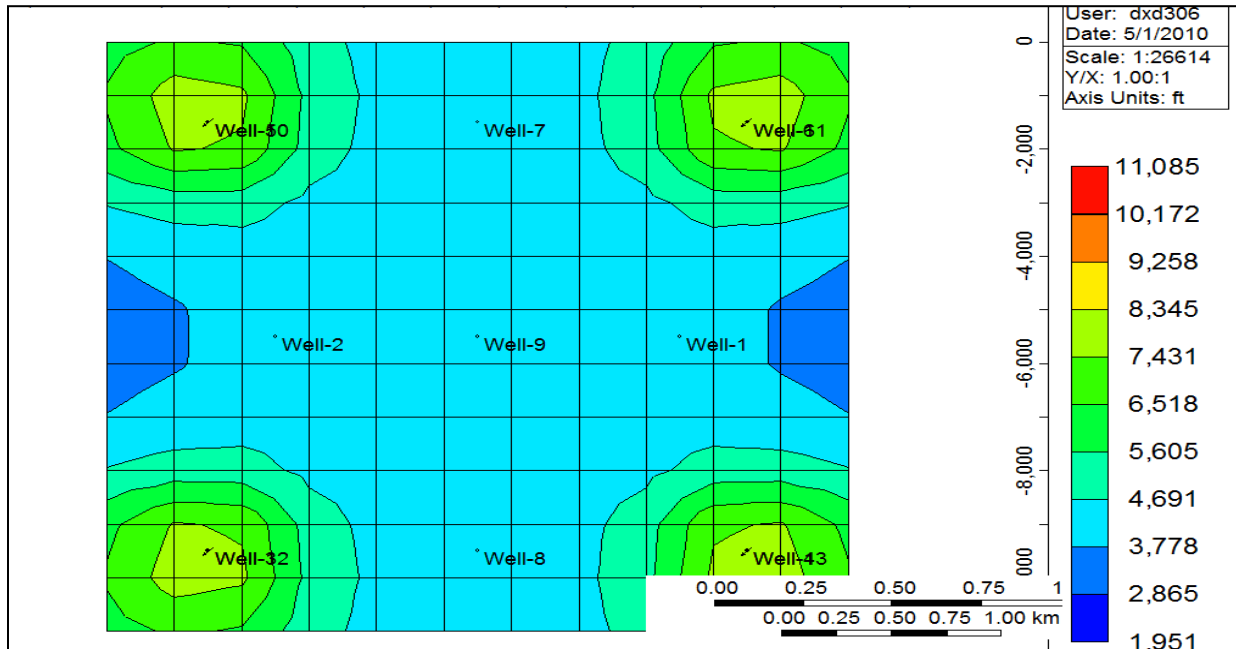
Figure 44: Pressure profile after 30 years of operation

After 30 years, we see that the pressure is at its maximum in the injection well blocks at around 11,000psia. So now we terminate the injection process, as not to exceed the fracture pressure limit of the formation.

6.9 Economic Analysis of Sequestration With in EOR

In making an economic analysis of EOR, we assume that the CO_2 is available at the site after transportation. We do not consider the capture cost, transportation cost and monitoring cost for the EOR.

Also, because we are doing secondary recovery, we do not need to drill new wells. Wells already drilled in the formation will be reworked and the cost of reworking will be considered.

These costs will be considered in the ultimate cost analysis. We will neglect the cost of injecting $Ca(OH)_2$, which will be injected after EOR for enhancing mineral trapping.

The purpose of the economic analysis is to evaluate the feasibility of CO_2-EOR. The main source of income in this process is coming from the recovery of 406.614 MSTB of oil. Major costs include the cost of O&M of wells and the recycling cost of CO_2. Table 15 below shows the economic analysis of EOR and includes the costs involved in EOR.[6.6]

VARIOUS COSTS ASSOCIATED	PER WELL PER YEAR($)	TOTAL(MM$)
reworking on existing wells	181968.75(constant for 1 well)	-1.64
operating & maintenance costs	111863.75 /year/well	-10.0677
CO_2 recycle cost	700,000Per MMcf/d	-5.131
CO_2 recycle O&M cost	1 per Mcf	-0.0733
Lifting costs	0.3per bbl	-0.122
G&A costs	27965.9.2+0.2*(0.3per bbl)	-2.0379
royalties	12.5% of total oil production	-4.57
Income from oil	90*406614	+36.59
total		+ 12.95

In table 15, (-) signs indicate expenses, and (+) signs indicate revenue. We use set oil prices at $90/bbl, over the ten production years. We see that a profit of $12.95 million is obtained in 10 years from CO_2-EOR. We not only make this profit, but we also sequester ten years emissions of CO_2 from the plant. When the above economic analysis is compared with economic analysis of CCS without EOR, we see that we make profit while achieving sequestration.

Chapter 7: Monitoring of Underground CO_2 Reservoirs

7.1 Introduction

Carbon capture and storage (CCS) may function as a means to successfully store anthroprogenically produced carbon dioxide (CO_2) for tens of thousands of years through geologic sequestration [7.1]. Long-term underground storage of CO_2 is a naturally occurring process most often observed in sedimentary basin in which pore spaces between clasts are infilled with gases, liquids, or supercritical liquids [7.2]. Enhanced oil recovery projects (EOR) projects have previously injected carbon dioxide into low outputting petroleum and natural gas wells to re-pressurize the reservoirs and encourage the migration of desired gases [7.3]. These projects have proven themselves successful and though there may be high capital project costs, there are many cost incentives through enhanced oil and natural gas production. An issue that remains is the related environmental and human health and safety issues from underground CO_2 injection. These issues are best understood through ongoing monitoring of CO_2 injection in order to characterize the effectiveness of long-term, underground sequestration. There are currently several suggested methods for monitoring underground CO_2 reservoirs and each has respective cost and benefits.

7.2 Statement of Purpose

The purpose of this investigation is to understand currently available monitoring technologies and apply their use to an underground CO_2 injection project in the Rose Run formation underlying a coal fired power plant located in Shawville, PA. This CCS project will have many associated retrofitting, transport, and injection costs, so it is the intention of this environmental health and safety survey to suggest sufficient monitoring methods at the lowest possible costs. To do this, existing monitoring networks across Pennsylvania will be utilized in order to minimize monitoring costs of the injection reservoir. Technologies will be adapted from the petroleum and natural gas and industrial health and safety industries as well as departments of environment protection to develop a complete and cost effective regional monitoring network above the Rose Run formation (RRF).

Before implementing a CCS retrofitting project in Shawville in, a complete risk assessment must occur to quantify the likelihood of damages if leakage were to occur. In order to successfully manage these risks, the costs and benefits of the project must be weighted to develop a logical and systematic approach to recognizing and reducing these risks. The frequency and likelihood of associated hazards for this project should be determined and the ultimate impact of geologic carbon sequestration must be understood. Hazards include exposure to harmful levels of CO_2, damage to groundwater and mineral resources, induced or enhanced seismicity, and the injury associated with projects [7.37] The primary sources of leakage (places of close proximity to hazards) are found along the pipeline transport networks, at pumping stations at the capture or injection stations, or from the geologic sequestration site.

7.3 Reservoir Assessment

7.3.1 Pre-injection Assessment

The regional geology of the RRF and the local water table must be considered before any injection programs can occur. A pre-injection assessment is critical to predict how injected induced pressures will affect reservoir characteristics. The Rose Run formation is located at a depth of 2500 meters and extends under Ohio, northern Kentucky, West Virginia, southwestern New York, southern Ontario, and Pennsylvania. Dozens of faults have been identified along the northern Appalachian Mountains, north-eastern Ohio, north-western Pennsylvania, and the eastern basin of Lake Erie [7.4]. These faults are predominantly southeast-northwest trending and may extend to thousands of meters in depth. Existing geologic surveys and LIDAR maps should be catalogued to identify and characterize land deformation due to injection. Tens of thousands of historic and active petroleum and natural gas wells cover this region and in addition to the faults, these wells are the greatest point sources for CO_2 leakage [7.5]. Potential leakage pathways must be identified prior to injection to reduce risks to environmental or human health as well as reduce future project costs relate to the management of these leaks. Recent investment into natural gas projects within the Marcellus shale will provide critical information about regional borehole well locations. Additionally these projects have ample subsurface data related to geological and mineralogical characteristics, aquifer depths, brine geochemistry, and reservoir temperatures and pressure information. Utilizing these operations existing data and background information can reduce our survey costs. After these parameters are thoroughly assessed and leakage risks are characterized, injection into the Rose Run formation may proceed.

7.3.2 Injection Monitoring

Monitoring of injected CO_2 is necessary to understand how a plume stabilizes or migrates within a reservoir in order to determine how long carbon dioxide can successfully be sequestered at a site. Site characterization of faulting and fractures must be understood in order to predict any migration or dispersal into local aquifers, which can pose risks to human and environmental health. These locations may serve as suitable monitoring sites because if CO_2 were to leak out of the reservoirs, it would flow along these paths of least resistance. The reservoir capacity and characteristics needs to be completely understood to successfully inject supercritical or liquid CO_2 into the formation. If the geologic site has sufficient porosity (space between clasts) and permeability (connection between pore spaces) in addition to impermeable cap-rocks, a site may be appropriate for underground injection. Figure 46 highlights appropriate injection rates within the Rose Run. The potential types of leakages that may occur at a sequestration site must be understood before deciding which type of monitoring should be employed. Between 0.10 and 0.35 Mt CO_2/year/well can be safely injected into the Rose Run formation. These injections rates allow for the desired diffusion rates into the reservoir while maintaining CO_2 in it the liquid or supercritical liquid form as well as the desired reservoir pressures [7.6]. Exceeding these injection rates may result in plume instability, a CO_2 phase change from the supercritical to the gaseous state, and CO_2 migration out of the reservoir.

Leakage or seepage can most readily occur from sites of well injection. As pressures within a reservoir build, gases or liquids will attempt to migrate to areas of lower pressure. By understanding fluid movements within a reservoir, models can be produced to better understand fluid migration and leakage [7.7]. The injection well often serves as a potential leakage source because it is directly connected to the primary reservoir. Wellhead injection rates, pressures, and temperatures must be understood and monitored to ensure proper sequestration and only ongoing observations will provide the necessary information to recognize the maturation of a sequestration site [7.8]. Because underground injection is a long-term sequestration strategy (tens of thousands of years), monitoring must be on going to ensure that the reservoir maintains desired pressures and characteristics. Understanding reservoir geochemistry is essential to the long-term sequestration of injected CO_2. Over time, geochemical reactions within the reservoir may dissolve certain minerals and open avenues for seepage. Old or abandoned mines, petroleum and natural gas wells pose similar risks to the primary injection well, again because building pressures can encourage plume migration. Because the Rose Run formation exists under a region of thousands of square miles, leakage pathways may develop across the reservoir. These abandoned well sites may serve as point sources of seepage and if they can be identified, these sites are excellent candidates for monitoring sites [7.9]. Faults and fractures provide additional point sources for seepage and only proper identification of these geologic features can ensure the overall viability of a sequestration site. With these sources of leakage in mind, several methodologies have been developed to monitor underground CO_2 leakage. Technologies will be adopted from the oil and natural gas industries for monitoring injected CO_2.

A majority of the detection technologies and risk monitoring of the CO_2 pipeline networks can be borrowed from existing pipeline networks developed by the oil and natural gas industries. Pipelines should avoid concentrated human populations to minimize any hazards associated with pipeline failure.

The pipeline infrastructure needs to be continuously monitored for leaks or signs of corrosion and pressure must be maintained during transport. Unlike the oil and natural gas transportation, the threats of explosions are minimal but if leakage were to occur, CO_2 gas may accumulate along lower lying topographies and threats of suffocation or carbon dioxide induced sickness may occur. Options may include adding some sort of chemical odorant to the transported CO_2 to act as a cheap early detection proxy [7.37].

Geologic sequestration site monitoring is essential to reduce the associated hazards from carbon dioxide leakage. The Rose Run formation has been determined to be a suitable site for retaining CO_2 for thousands of years. As seen in figure 47, there are many abandoned oil and natural gas wells that may serve as vectors for carbon dioxide leakage. After identifying these abandoned oil and natural gas wells, those deemed likely to serve as point sources of leakage must be properly plugged to ensure the long-term stability of the sequestration reservoir. It is vitally important to understand reservoir maturation through ongoing monitoring to determine if leakage was to occur, would it be a chronic, small scale leak or an acute, catastrophic large discharge scenario.

7.4 Monitoring Techniques

7.4.1 Optical Fibers

A majority of the monitoring technologies that can be applied to geologic sequestrations sites have been developed by the oil and natural gas industries. Optical fiber sensors have previously been employed in natural gas wells as downwell sensors that respond to varying reservoir characteristics. Regional monitoring networks of these optical fibers can be utilized to create underground reservoir pressure maps that can then be used to characterize any gas migration within the system [7.10]. This technology has been successful in oil reservoir modeling, but large-scale applications to carbon sequestration sites and the associated costs have not been fully explored. While the costs for application towards a project like the RRF remains uncertain, optical fibers are easily installed or replaced, cheap to use and extremely effective in measuring reservoir properties [7.11]. Because the RRF is a vast geological formation, site location for these optical sensors is dependent on the pre-injection assessment. If leakage pathways have previously been identified, regional optical fiber networks should be installed in already existing, functioning or abandoned wells or in the direct injection wells to minimize associated drilling costs. Brown and Hartog (2002), suggest that the cost may as low as $20 per sensor, but a National Energy Technology Laboratory (NETL) study conducted in 2006 to assess methane leaks required an operational project budget greater than $550,000 [7.12]. An optical fiber network contained within a 25-mile radius of the Shawville plant should provide a sufficient monitoring network for this injection project [7.13]. Figure 48 highlights this 25-mile radius feature because it is believed that injection into a reservoir within this geographical scale will prevent a potential overlap between other regional power plant injection schemes. If other coal-fired power plants enact similar geologic sequestration strategies, the costs with this regional optical fiber network may be reduced if each plant enters a regional monitoring network partnership. A partnership of this nature would provide a better of assessment of environmental health through a more complete identification of reservoir characteristics or leakage pathways. In additional to optical fibers, alternative sensor systems exist and these types of devices may

be useful for modeling underground carbon dioxide. It seems, however, that optical fibers may be most cost-effective for the purposes of a sequestrations project within the Rose Run formation. Above ground detection devices are also readily available and are proven tools in detecting carbon dioxide in soils, water tables, and air. These additional techniques my also be used.

7.4.2 Gas Detection

The environmental health and safety industries have also developed a variety of monitoring tools for CO_2 detection, which observe carbon dioxide concentrations within a water table, soils, and surface air [7.14]. These monitoring techniques are well understood and can easily be applied to the areas above an injection well to model any sources of seepage or leakage. Because CO_2 dissolves in water to form carbonic acid, simple pH monitoring of regional lakes and rivers can provide critical information about point sources of reservoir seepage. Gas chromatography and IR detection are additional monitoring tools that have been implemented by occupation health and safety groups and have proven successful in atmospheric detection of carbon dioxide [7.15]. Monitoring tools used to understand volcanic activity may also be applied to a sequestration site. Variations in CO_2 emissions from active and dormant volcanoes have been successfully observed by the USGS using LI-COR detectors and if sensor networks are applied to a sequestration site, reservoir leakage models can be created [7.16,7.17]. Volcano monitoring devices may prove extremely useful if these technologies are applied to sequestration reservoirs if they are cost-effective. Remote sensing devices, specifically satellites have been used to monitor atmospheric carbon dioxide concentrations, but this technology has previously been unable to detect low-concentration leakage and may not be appropriate for onsite detection [7.18]. While some of these technologies are potentially costly, some are already in use for general environmental monitoring. The scales of geologic sequestration sites can be immense and multiple forms of monitoring devices may need to be employed to develop an efficient characterization of CO_2 injection. Monitoring will only prove successful if it is cost-effective and reliable in characterizing CO_2 leakage to prevent damages to humans and ecosystem health [7.19]

International space agencies have already devoted substantial resources to the detection and monitoring of the carbon cycle. While these projects are extremely expensive, we can utilize their networks to further develop our Rose Run formation monitoring network. The National Aeronautics and Space Administration (NASA) and the Japan Aerospace Exploration Agency (JAXA) have put several important satellites into orbit that freely provide information to the public related to their observations. Airborne laser swath mapping (ALSM) can be used in monitoring ground deformation. NASA's Orbiting Carbon Observatory (OCO) suffered launch failure in February of 2009 (a $250 million loss to taxpayers) but has received 2010 budget approval for $170 million. When re-launched, the OCO project can be used to monitor and identify carbon fluxes on extremely small spatial scales [7.38]. If significant leakage were to occur, this satellite could successfully identify and quantify the leakage. JAXA launched the Greenhouse Gases Observing Satellite (GOSAT) in January of 2009. This satellite, like OSO, has centimeter scale resolution in monitoring carbon fluxes [7.39].

7.4.3 Geochemical Monitoring

Past land-use histories must also be considered specifically related to abandoned mines, oil, and natural gas wells, which can serve as point sources for CO_2 leakages [7.20]. This background environmental

information is critical for understanding and qualifying changes that may occur from underground injection of carbon dioxide.

Geochemical tracers are excellent tools for understanding the physical status of injected carbon dioxide as well as the interactions that occur between the CO_2 and the other minerals and chemicals that may exist within a geologic reservoir [7.21]. Work by Gunter *et al.,* [7.22] suggests that by collecting fluid samples from bore wells, real-time monitoring of a CO_2 reservoir can create useful models that characterize fluid migration and reactions. Isotopic measurements of these collected bore well fluids can also convey the movements and interactions of injected carbon dioxide within the reservoir [7.23]. The previously described monitoring techniques are well understood, but the related costs and effects of the interactions between injected CO_2 and the local geologic makeup need to be further studied. Their application may be limited in our Rose Run project because of potentially high associated costs. Regional water quality networks are already being used by environmental agencies and Marcellus shale operations extensively collect these bore well samples. Our project may be able to reduce its costs by utilizing these existing monitoring and collection networks. The costs may still be substantial, but necessary to protect environmental health.

Data collected from well logs though potentially costly, are proven tools in detecting CO_2 migration. A variety of devices exist that can be inserted into an injection well to collect and characterize the data to better model an underground CO_2 reservoir [7.24]. Fluid analysis of well-logs can be used to determine the time-lapsed effects of CO_2 injection. By analyzing fluids across a reservoir, migration modeling can determine how and where injected CO_2 is chemically reacting within a reservoir [7.25]. Geophysical models including gravitational, seismic, and electromagnetic analyses have been employed in other fields to understand reservoir characteristics and these same technologies can be applied to sequestration sites [7.26]. Physical observations from satellites, LIDAR, and on the ground observations can be implemented in order to assess the land surface deformation that may result from reservoir injection [7.27]. The implementation of these detection methods must be based on the limitations and accuracy of the detection devices and how specifically these detection methods isolate the effects from underground CO_2 storage from background reservoir characteristics. When all these pieces of information are connected, three-dimensional seismic models can be created to observe any migration of CO_2 within the reservoir [7.28].

There are several associated risks to environmental and human health related to an underground CO_2 injection project. Increased reservoir pressures may activate faults or fractures, causing land subsidence or deformation and induced seismicity may occur from injection [7.29]. Dependence on national and regional seismic networks will be critical for monitoring any land movements. Perhaps the greatest threat to human and environmental safety is the mobilization of heavy metals. pH changes in reservoir geochemistry resulting from carbon dioxide injection may encourage the dissolution of certain heavy metal containing minerals [7.30]. These heavy metals may migrate within or out of the reservoir and end up intruding into regional aquifers. Monitoring of these heavy metals could potentially be extremely costly if we installed our own detection network. Instead, we can use an already established Pennsylvania Department of Environmental Protection (PDEP) water-monitoring network. By comparing historic water quality data to post-injection data, we can back track and potentially locate point sources

of heavy metals and identify leakage sites. Figure 49 shows sites of ongoing water monitoring in Pennsylvania. Several of these sites overly our sequestration reservoir and can serve our project's monitoring purposes. Comparisons of historic data to newly acquired data after injection can prove useful in ongoing site monitoring. Figure 50 shows the major aquifers that underlie the region around Shawville. Any observed impacts to water quality would likely occur in these aquifers.

7.4.4 Bio-monitoring

While many monitoring devices utilize advanced technologies, bio-monitoring may prove to be the simplest and cheapest method to observe potential leakage sites of carbon dioxide. An assessment of ecosystem diversity before a site is used for underground CO_2 storage can provide important background information about ecosystem health. After reservoir injection, ongoing observations of changes in the ecosystem health can be used to determine if leakages are negatively impacting local flora and fauna and specifically locate sources of seepage [7.31]. Because carbon dioxide is heavier than air, it tends to settle in low-lying areas or accumulate within soils. When enough CO_2 accumulates, gases can kill trees, bacteria, fungi, and when conditions are extreme, animals in these areas can suffocate [7.32]. Trees are further susceptible to changes in soil pH and the interaction of carbon dioxide and ground water may encourage changes in soil profile chemistry and lead to tree mortality. Figure 51 shows an image taken by the USGS of tree kill on Mammoth Mountain that resulted from CO_2 fumaroles. Similar tree kill may occur from carbon dioxide leaks at the surface and ongoing forest assessments may prove useful for monitoring purposes.

Beyond already existing forests, tree planting schemes may provide several potential benefits. A form of bio-sequestration, these trees may financially benefit the Shawville plant through some form of carbon credit scheme and additional profits may be gained from the sale of timber. Trees can additionally provide landscape stability that may reduce the threats from land deformation. Figure 52 shows the currently land-use demographics for Pennsylvania. Pennsylvania is well-endowed with forest resources and we can utilize these resources for leakage monitoring and potentially a source to generation profits from biomass sales. To enhance these forest monitoring networks, ideally we would enact large-scale forestation plans. Pennsylvania legislators have already suggested several tree planting plans, but the region around Shawville appears to have reached an equilibrium between agricultural and forest resources. Forestation opportunities, however, do exist because of increasing tree mortality over the last decade. The forested regions around Shawville have been heavily impacted by gypsy moth and silk worm induced tree kill. Over 400,000 acres of formerly forested land are poised for reforestation projects. Using conservative tree plantation estimates, over 176 million trees could be planted across this area, creating more than 80,000 tons of biomass that may be available for future harvest [7.40].

The greatest benefit from bio-monitoring may be its precision in locally identifying point sources of environmental degradation [7.33]. Through ongoing bio-monitoring, leakages can be identified and because this monitoring method may require only observation, it can be quickly and cheaply implemented at a geologic sequestration site.

7.5 Costs associated with monitoring

Monitoring is an essential component of the application of CCS technologies. Monitoring techniques will only prove useful if they are efficient and cost-effective. Two approaches are taken to addressing the costs of monitoring at this project within the Rose Run formation. The first approach of cost analysis will be based off of an "envisioned, all encompassing monitoring network." The second cost analysis approach will be based off of more standardized industry cost assessments.

This "envisioned monitoring network" will include already installed monitoring devices and those that will need to be implemented on behalf of the project. Table 16 highlights the determined associated monitoring costs with a CCS retrofitting project in Shawville, PA. The costs associated with our project include ground deformation sensors, borewell sensors, biomonitoring, and water quality monitoring. LiDAR technologies can be used to monitor the region around Shawville at cost of approximately $0.05/acre and cost the overall project $1.6 million dollars per year [7.41]. Borewell costs include the cost of drilling eight monitoring wells and inserting optical fiber sensors. These technologies will cost the project $80 million over the lifetime of the project. Biomonitoring costs are based off of a reforestation plan across the 400,000 available acres. At a cost of $840 per acre and at a plantation scale of 440 trees per acre, $336 million dollars would be needed for the forestation monitoring project during the initial year. During the lifetime of the project, taking the average value of a mature hardwood tree at $3.23 per tree, we could generate $568 million dollars in profit from the sale of timber [7.42]. The costs of using GOSAT and DEP Water Quality networks will not add additional costs to the monitoring project.

Table 16: Cost associated with geologic sequestration project near Shawville, PA

Monitoring Device	Cost ($)/year 1	Benefit ($)/lifetime
LiDAR	1,612,274	0
Borewell Sensors	80,000,000	0
Biomonitoring	336,000,000	568,480,000
DEP Water Network	0	0
GOSAT	0	0
Total Costs	-	+150,867,726

These cost assessments can only be considered crude estimates because few monitoring networks for geologic carbon sequestration sites exist. These offered costs represent the author's ideal envisioned monitoring network and cannot be considered completely applicable to the feasibility of this project.

Table 17 offers associated project costs based off of the available literature related to geologic carbon sequestration monitoring. McCoy and Rubin (2005) base their monitoring costs off of similar monitoring networks related to the transport and storage of petroleum and natural gas products. Costs are broken down into high, average, and low costs. These dollar ($) per ton of CO_2 costs are based off of transport and storage networks of existing natural gas pipeline networks. High costs reflect scenarios where transport distances are significant and regional topographic barriers require substantial transportation infrastructure. Low costs represent shorter distances across gradual topographic changes. To sequester CO_2 from the Shawville power plant would cost the project between $13 and $4 million dollars per year per well in monitoring costs.

Table 17: Associated monitoring costs based of Rubin and McCoy (2005) estimates

McCoy & Rubin (2005)	High Cost ($/ton)	Average Cost ($/ton)	Low Cost ($/ton)
Monitoring Costs	0.10	0.07	0.03
CO2 Injected (tons)	3,366,000	3,366,000	3,366,000
Total Costs ($)	13,348,000	9,440,000	4,040,000

7.6 Conclusions

While a variety of CO_2 monitoring devices exist, each geologic sequestration site has its own unique characteristics and a monitoring network must be tailored to each specific site. Underground reservoir monitoring technologies developed by other industries can be applied to our Rose Run formation injection project, but because other injection projects are still in the pilot program stage, sufficient data is lacking. Each monitoring method has its respective pros and cons and a combination of several monitoring methodologies may prove to best characterize the maturation of carbon dioxide injected reservoirs [7.34]. It appears that monitoring of underground injection reservoirs is possible, however, cost barriers are not fully understood and this may limit the overall viability of successful monitoring for geologic sequestration of carbon dioxide. If we can use already installed monitoring networks, costs can be minimized and monitoring of a Shawville injection project may prove more feasible. Because geologic sequestration is a long-term commitment, public education and awareness will be essential for the vitality of this project. There may be additional incentives from public involvement projects like water quality monitoring, tree planting, or ecosystem surveys. The costs will be burdensome, but monitoring is essential for the long-term sustainability of a Rose Run formation injection project.

Chapter 8: Project Conclusions and Recommendations for Future Work

8.1 Cost Analysis

The following table represents the cost break down for the first ten years of CCS operation within EOR, including all associated costs.

Table 18: Ten year Combined Cost Analysis

VARIOUS COSTS	PER WELL PER YEAR($)		TOTAL(MM$)
Transportation Costs	$31 million		-310
Capture Costs	0.003264 per scf		-1746.04
Tax Incentives	$90 years 0-5 $50 years 5-10		+2408
reworking on existing wells	181968.75(constant for 1 well)		-.6377
operating & maintenance costs	111863.75		-10.06
Co2 recycle cost	700,000Per MMcf/d		-5.13
Co2 recycle O&M cost	1 per Mcf		-.073
Lifting costs	0.3per bbl		-0.12
G&A costs	27965.9.2+0.2*(0.3per bbl)		-2.04
royalties	12.5% of total oil production		-4.57
Income from Oil			+36.59
Monitoring Costs			292.5
total			77.42

After a combined 30 year period, assuming the initial 10 years of EOR and then 20 years of CCS without EOR, the following economic structure of cost is represented in table 19. A discount factor of 4% was considered in this analysis to determine the net present value.

Table 19: 30 year Combined Cost Analysis

VARIOUS COSTS	PER WELL PER YEAR($)		TOTAL(MM$)
CO_2 capture cost	. 0.003264per scf	-	-5232.1
Transportation cost	31MM		-930
Tax incentives	$90 years 0-5 $50 years 5-10		+2408
Income from Oil Production	-		+36.59
reworking on existing wells	181968.75(constant for 1 well)		-1.64
converting production well into injection well	78391.25(constant for 1 well)		-0.31
operating & maintenance costs	111863.75		-19.02
CO_2 recycle cost	700,000Per MMcf/d		-5.131
CO_2 recycle O&M cost	1 per Mcf		-0.073
Lifting costs	0.3per bbl		-0.12
G&A costs	27965.9.2+0.2*(0.3per bbl)		-2.03
royalties	12.5% of oil price		-4.57
Monitoring cost	8.7 MM		-552.5
Total			-4,302.90

8.2 Conclusions and Recommendations

After an evaluation of the available technologies and implementation to the Shawville pulverized coal power plant, this study shows that carbon capture and storage is economically feasible with the utilization of enhanced oil recovery and additional bonus incentives from the government, beyond the first ten years, of $46.87 per ton of CO_2 captured. Current policies and house bills show an increasing effort by both the federal and state governments to establish both an effective carbon cap-and-trade program and laws that provide bonus incentives in the form of carbon credits. It is clear from this study that the support from the government and related agencies is absolutely essential in order to make CCS projects economically feasible. An analysis was performed for the most developed commercial scale carbon capture technology, MEA absorption, and compared with a new and promising technology, CAP. Through literature review and software analysis, the two processes were applied to the Shawville plant and it was determined that MEA absorption is the better, currently available technology on the basis of economics. The process shows an energy penalty of 11.7%, which brings the total thermal efficiency of the power plant down to 20.5%, and an avoided cost of $57.06 per ton of CO_2 captured.

Hydraulic parameters studied in Midwest Regional Carbon Storage Partnership region (MRCSP) show the Rose Run formation is a suitable storage site. In order to determine the best available injection site for this CCS project, the Ogden and CMU correlation economic models were compared. The annualized total capital costs of these two transportation scenarios yielded significantly different results. Pipeline length is the key parameter for associated transportation costs because of variations in construction and infrastructure capital. Transportation costs can be minimized if CCS technologies are utilized within an enhanced oil recovery paradigm. Our ultimate storage site will be set up after implementation of geologic carbon sequestration within EOR. The potential of CO_2-EOR is globally significant and the United States is poised to benefit from its domestic application. CCS can also be done within EOR to mitigate the greenhouse gas effect of CO_2.

Transportation of CO_2 is a very expensive process. Further research is needed to make transportation cheaper by working on better pipeline networks. As was found in this study, the capture cost is the major contributor to economic viability of the project. Additional research on both pre-combustion, most notably oxy-combustion, and post-combustion technologies needs to be performed in order to bring associated costs down. Also more research on injection well technology (including fracturing for producing more oil in EOR) is necessary to maximize the injection of CO_2 and also make the injection of calcium hydroxide easier and more efficient. In terms of CCS applications, we should try to find ways to enhance mineral trapping over other trapping mechanisms. Collaboration between industry leaders, universities, and government entities is the best option for achieving these goals. Projects will only be accepted by the public if they do not substantially raise electricity prices and are ensured to be safe to the regional environmental health and human safety. Ongoing monitoring at geologic carbon sequestration sites is essential to ensure the sustainability of these carbon capture and storage projects. This study concludes that the application of CCS technologies to the Shawville power plant is only feasible through further economic subsidizes, however, ongoing battles in global politics and public interest in reducing greenhouse gas emissions may encourage a drive towards accepting these expensive technologies.

Appendix A – Capital cost for CO_2 Pipeline Transportation

A1. Parameters

The calculation of compressor and pump power requirements should be based on the following variables using the Ogden Model:

Pinitial = 435 psia

Pfinal = 2200 psia

Pcut-off = 1070 psia

Table 20: Case study input parameters and distributions for the transport models

Parameters	Rep. Value	Distribuition
Design CO_2 Mass Flow(Mt/year)	3.4	Uniform
Power Plant Capacity Factor(%)	90%	Uniform
Capital Recovery Factor	0.15/yr	Constant
Pipeline Transport Model Parameters		
Inlet Temperature(°F)	53.6	Constant
Inlet Pressure(pisa)/(Mpa)	2200/15.2	Constant
Outlet Pressure(psia)/(MPa)	1500/10.3	Constant
Total Pipeline Length(ft)	132000/1320000	Uniform
Pipeline Elevation Change(m)	0	Constant

Nomenclature

m = CO_2 mass flow rate to be transported to injection site [tonnes/day]
$P_{initial}$ = initial pressure of CO_2 directly from capture system [MPa]
P_{final} = final pressure of CO_2 for pipeline transport [MPa]
$P_{cut-off}$ = pressure at which compression switches to pumping [MPa]
N_{stage} = number of compressor stages [-]
CR = compression ratio of each stage [-]
$W_{s,i}$ = compression power requirement for each individual stage [kW]
Z_s = average CO_2 compressibility for each individual stage [-]
R = gas constant [kJ/kmol-K]
T_{in} = CO_2 temperature at compressor inlet [K]
M = molecular weight of CO_2 [kg/kmol]
η_{is} = isentropic efficiency of compressor [-]
$k_s = (C_p/C_v)$ = average ratio of specific heats of CO_2 for each individual stage [-]
$W_{s\text{-total}}$ = total combined compression power requirement for all stages [kW]
$(W_s)_1$ = compression power requirement for stage 1 [kW]
$(W_s)_2$ = compression power requirement for stage 2 [kW]

N_{train} = number of parallel compressor trains [-]
W_p = pumping power requirement [kW]
ρ = density of CO_2 during pumping [kg/m^3]
η_p = efficiency of pump [-]
m_{year} = CO_2 mass flow to be transported and stored per year [tonnes/yr]
CF = capacity factor [-]
m_{train} = CO_2 mass flow rate through each compressor train [kg/s]
C_{comp} = capital cost of compressor(s) [$]
C_{pump} = capital cost of pump [$]
C_{total} = total capital cost of compressor(s) and pump [$]
C_{annual} = annualized capital cost of compressor(s) and pump [$/yr]
CRF = capital recovery factor [-/yr]
C_{lev} = levelized capital costs of compressor(s) and pump [$/tonne CO_2]
$O\&M_{annual}$ = annual O&M costs [$/yr]
$O\&M_{factor}$ = O&M cost factor [-/yr]
$O\&M_{lev}$ = levelized O&M costs [$/tonne CO_2]
E_{comp} = electric power costs of compressor [$/yr]
p_e = price of electricity [$/kWh]
E_{pump} = electric power costs of pump [$/yr]
E_{annual} = total annual electric power costs of compressor and pump [$/yr]
E_{lev} = levelized O&M costs [$/tonne CO_2]

A2. Calculation of Compressors/Pumps Power Requirements

```
clear;

clc;
```

```
%%%%%%%%%%%%% Compression Power Requirements%%%%%%%%%%%%%%
```

```matlab
Pinitial=3; %MPa

Pfinal=15.2; %MPa

Pcutoff=7.38; %MPa

Nstage=2;


CR=(Pcutoff/Pinitial)^(1/Nstage); %compression ratio


R=8.314; %KJ/kmol-K

M=44.01; %kg/kmol

Tin=313.15; %K(40C)

nis=0.75; %isentropic effieiency of compressor


Zs=[0.935;0.845]; %average CO2 compressibility of each individual stage

Ks=[1.379;1.704]; %average ratio of specific hears of CO2 for each individual
stage

m=3.4*10^6*0.9/360; %mass flow rate ton/day


for i=2

    Ws(i)=(1000/24/3600)*(m*Zs(i)*R*Tin/M/nis)*(Ks(i)/(Ks(i)-1))*(CR^((Ks(i)-
1)/Ks(i))-1);   %KW%

end


Wstotal=sum(Ws(i)); %KW%


Ntrain=Wstotal/40000; %number of parallel compressor trains


Ntrain=1;

%%%%%%%%%%%%%%%%%Pupming power requirement for boosting the CO2 pressure
```

```
%%%%%%%%%%%%%%%from Pcutoff(7.38MPa) to Pfinal(15.2MPa)%%%%%%%%%%
```

```
r=630;   %kg/m^3

np=0.75;   %efficiency of pump

Wp=(1000*10/24/36)*(m*(Pfinal-Pcutoff)/(r*np));
```

A3. Capital, O&M, and Levelized Costs of CO_2 Compression/Pumping

```
%%%%%%%%Costs of CO2 compression%%%%%%

mtrain=(1000*m)/(24*3600*Ntrain); %CO2 mass flow to be transported and stroed
per year [tonnes/yr]

Ccomp=mtrain*1*((0.13*10^6)*(mtrain^(-0.71))+(1.4*10^6)*(mtrain)^(-
0.6)*log(Pcutoff/Pinitial));   %$%
```

```
%%%%%%%%Costs of CO2 pump%%%%%%%%%%%%%%

Cpump=(1.11*10^6)*(Wp/1000)+0.07*10^6;
```

```
%%%%%%%%%%Total capital costs%%%%%%%%%%

Ctotal=Ccomp+Cpump;

CRF=0.15; %capital recovery factor

Cannual=Ctotal*CRF;

CF=0.9; %capacity factor

myear=m*360;
```

```
%%%%%%%%%%%%%Levelized capital costs(Clev)%%%%%%%%%

Clev=Cannual/myear;
```

```matlab
%%%%%%%%The annual operation and maintenances

%%%%%%%%costs(OM)annual%%%%%%%%%%%%%

OMfactor=0.04;

OMannual=Ctotal*OMfactor;




%%%%%%%%%%%%%Levelized O&M cost%%%%%%%%%

OMlev=OMannual/myear;



%%%%%Total electric power costs of compressors(Ecomp)and

%%%%%pump(Epump)%%%%%%%%%

Pe=0.065; %eletricity price $0.065/kWh

Eannual=Pe*(Wstotal+Wp)*(CF*24*360);

Elev=Eannual/myear;




%%%%%%%%%%%%Total annual and levelized costs of CO2

%%%%%%%%%%%compression/pumping%%%%%%%%%

Tannual=Cannual+OMannual+Eannual;

Tlev=Clev+OMlev+Elev;
```

A.4 Determine the Diameter of Pipeline

It is assumed that the transportation distance for the Colfax Field is 1320000ft(250 miles) away from the Shawville plant and underlying storage radius is 132000ft(25 miles). It's a 572MW coal plant with CO_2 emission of 3.4 million tons/year and the capital factor is 0.9. Since the calculation of pipeline diameter is an iterative process, one must first guess a value for diameter (D). A reasonable first approximation is D=10inches.

An estimation of the density (ρ) and viscosity (μ) of CO_2 in the pipeline (approximated at T and Pinter) is also required. We choose to use [4.12] to get approximation values. The Reynold's number (Re) and Fanning friction factor (Ff) for CO_2 fluid flow in the pipeline are calculated by the following equations from [4.13]

```
clear;

clc;


Pin=15.2; %Pipeline inlet pressure MPa

Pout=10.3; %Pipeline outlet pressure


Pave=2/3*(Pout+Pin-Pout*Pin/(Pout+Pin));


D=10; %Initial guess of pipeline diameter

delP=Pin-Pout;

L=400; %pipeline length km

m=8500; %mass flow rate tonns/day

v=1.06*10^(-4);   %viscosity

d=930.56; %km/m^3

e=0.00015; %roughness in ft


del=10;

while del>=0.01

Re=(4*1000/24/3600/0.0254)*m/(pi*v*D);

Ff=1/(4*(-1.8*log10(6.91/Re+(12*(e/D)/3.7)^1.11))^2);
```

```
Dnew=(1/0.0254)*((32*Ff*m^2)*(1000/24/3600)^2/(pi^2*d*(delP/L)*10^6/1000))^(1
/5);

del=Dnew-D;

D=Dnew;

end
```

A.5 Pipeline Transportation cost

```
clear;

clc;

%%%%%%%%%%%%CMU Correlation%%%%%%%%%

m=8500;

b=42404;

D=16; %inches

x=1.035;

L=217.5; %miles

y=0.853;

z=1.516; %region weights

LCC=b*D^x*L^y*z;

OM=5000; %$5000/mile

OMcost=5000*L;

CRF=0.15;

Annualized=LCC*CRF+OMcost;

myear=m*360;

LC=Annualized/myear;
```

APPENDIX B – EOR Calculations

B.1 Various costs involved in EOR process

These cost formulas have been taken from case studies of CO_2–EOR in Illinois and Michigan basin in 2004. In order to make them relevant for 2011, we add 25% extra in each cost.

1. Cost of Converting Existing Production Wells into Injection Wells.

   Well Conversion Costs = c0 + c1D
   Where: co = $10,438 (fixed)
   c1 = $6.97 per foot
   final Well Conversion Costs=1.25*(c0 + c1D)

2. Costs of Reworking an Existing Waterflood Production or Injection Well for CO2-EOR (First Rework).

   Well Rework Costs = c1D
   Where: c1 = $19.41 per foot
   D is well depth
   Final cost =1.25*(c1D)

3. Annual O&M Costs, Including Periodic Well Workovers.
   Well O&M Costs = b0 + b1D
   Where: b0 = $24,166 (fixed)
   b1 = $8.71 per foot
   D is well depth
   Final cost= 1.25(b0 + b1D)

4. Carbon dioxide Recycle Plant Investment:
   The cost of the recycling plant is set at $700,000 per MMcf/d of CO2 capacity.

5. Carbon dioxide Recycle O&M Costs.
   $0.25 per Mcf @ $25 Bbl oil.

6. Lifting Costs: $0.25 per barrel.

7. G&A Costs: 20% of well O & M and lifting costs

8. Royalties: Royalty payments are assumed to be 12.5%.

B.2 Calculation of Original Oil in Place (OOIP) In Coalfax Field

N=(7758bbls/Ac-ft)Ahφ(1-Swc)/Boi

Where

N   =Original oil in place(STB)
A   = Drainage area(Acre)   =130Acre
h   = thickness(ft)   = 26.6-27ft
φ   = porosity   = 17.1%
Swc = connate water saturation   =41.8%
Bo i= initial oil formation factor (rb/STB)=1.17-1.21

N=(7758*130*27*0.171*0.582)/1.21 to (7758*130*26.6*0.171*0.582)/1.17

 N=2239.7 MSTB to 2281.95 MSTB

Appendix C – CCS Monitoring

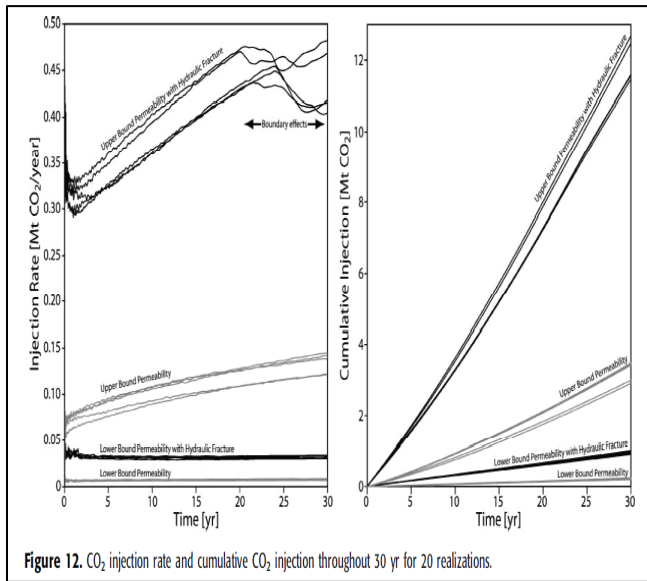Figure 12. CO₂ injection rate and cumulative CO₂ injection throughout 30 yr for 20 realizations.

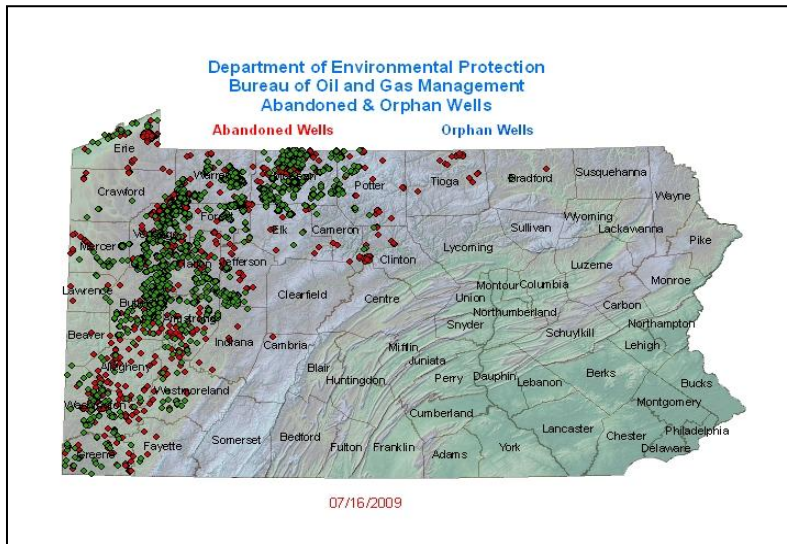**Figure 46: Hypothetical injection rates (Mt CO_2/year) in Rose Run Formation. [7.35]**

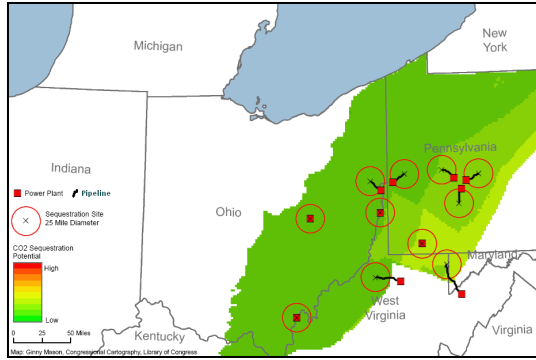**Figure 47: Abandoned oil and natural gas well in Pennsylvania [7.43]**

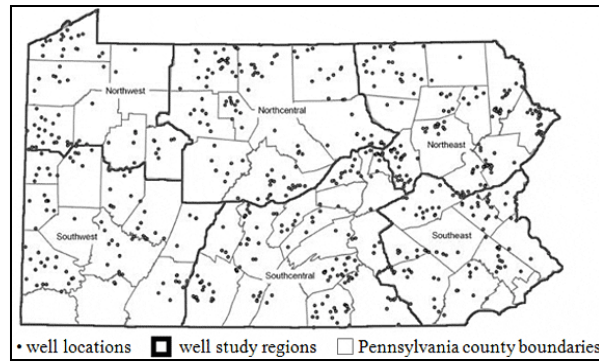Figure 48: Hypothetical CO$_2$ pipelines to Rose Run formation. [7.36]

Figure 49: Pennsylvania Department of Environmental Protection Water Monitoring Network [7.44]
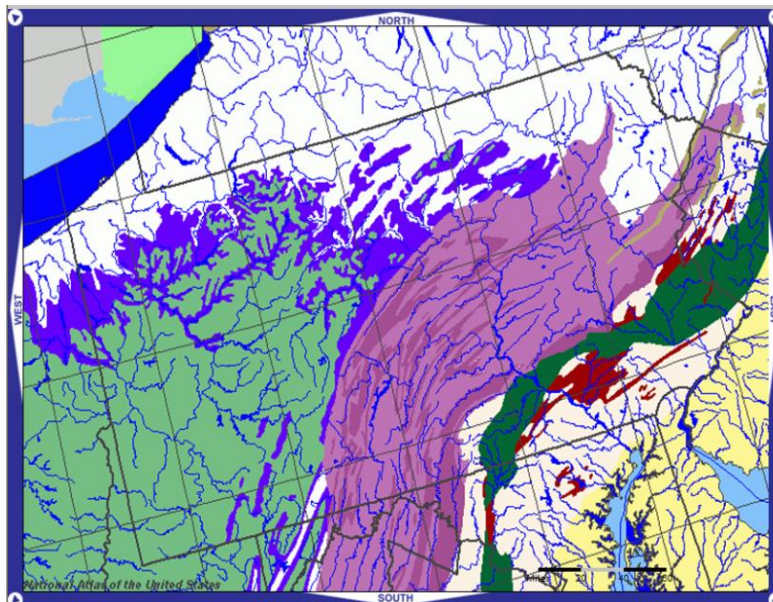

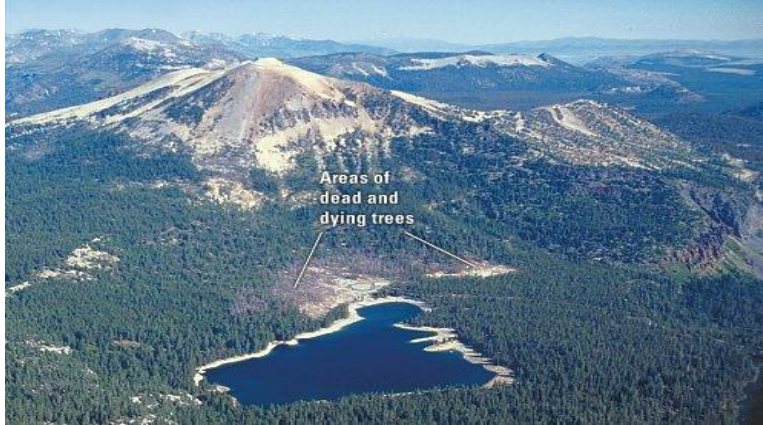Figure 50: Major aquifers in Pennsylvania

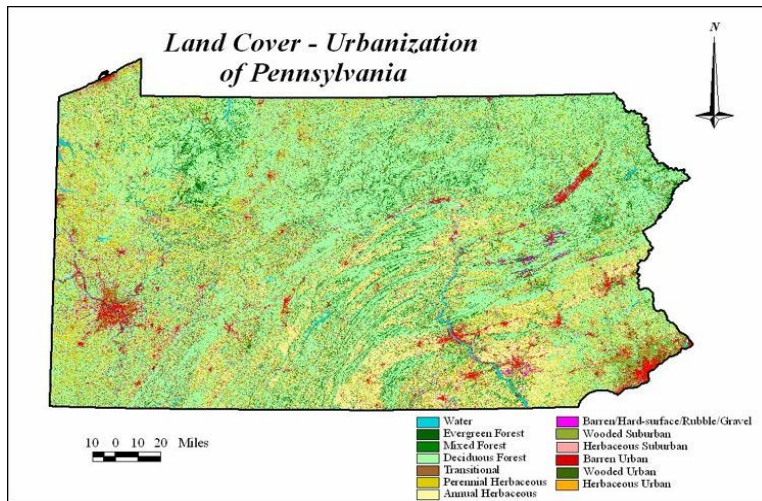Figure 51: kill at Mammoth Mountain from CO_2 fumaroles [7.45].

Figure 52: Land cover of Pennsylvania [7.46].

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