

Carbon Sequestration: Developing an assessment of potential CO₂ storage resources in Massachusetts

**Final Report:
Estimate of CO₂ Storage Resource Potential in Massachusetts Saline
Aquifers and Unmineable Coal Seams**

**Prepared for the Massachusetts Clean Energy Center under Task Order
09-1**

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Table of Contents

Chapter One: Executive Summary.....	4
Chapter Two: Introduction	6
2.1 Overview of Carbon Sequestration	6
2.2 Scope of Project.....	8
2.3 Organization of Project.....	9
2.4 Schedule.....	10
Chapter Three: Geologic Carbon Storage.....	11
3.1 General Site Selection Criteria.....	11
3.2 Deep Saline Aquifers.....	11
a. Description	11
b. Location	12
3.3 Organic Rich Shales	20
a. Description	20
b. Location	20
3.4 Unmineable Coal Seams	20
a. Description	20
b. Location	21
3.5 Deep Basalts.....	25
a. Description	25
b. Location	26
3.6 Organic Rich Schist and Slate	27
a. Description	27
b. Location	27
Chapter Four: Methods and Data Needs for Determining Storage Capacity	30
4.1 Introduction	30
4.2 Saline Aquifers.....	30
Screening Criteria.....	31
Volumetric Model Data	33
Summary of Massachusetts Saline Aquifer Resources with Comparison	35
4.3 Unmineable coal seams.....	36
Screening Criteria.....	37
Volumetric Model Data	38
Summary of Massachusetts Unmineable Coal Seam CO ₂ resources	41
4.4 Organic Rich Shales	41
4.5 Deep Basalt.....	42
4.6 Organic-Rich Schist and Slate.....	43
Chapter Five: Estimates of CO₂ storage resources in Massachusetts.....	44
5.1 Introduction	44
5.2 Estimate of CO ₂ storage resource in saline aquifers	44
a. Deerfield Basin, Sugarloaf Arkose	44
b. Hartford Basin, Sugarloaf Arkose.....	45
c. Summary of CO ₂ storage in saline aquifers of the Connecticut River Valley	47
5.3 Estimate of CO ₂ storage resource in unmineable coal seams	48
5.4 Storage in basalt, shale and organic-rich schists	52
Chapter Six: Summary and Recommendations	54
Chapter Seven: Implication of Results and Next Steps	56
Site Characterization.....	57
Conveyance System and Permitting.....	57
References	58
Appendix 1: Adsorption Isotherm Study.....	62

Chapter One

Executive Summary

Geologic carbon sequestration, defined as the permanent storage of CO₂ in underground geologic reservoirs, is emerging as an important strategy towards mitigation of increasing accumulation of CO₂ in the atmosphere and associated greenhouse gas warming and climate change. These efforts have been organized nationally through programs such as the U.S. Department of Energy – Office of Fossil Energy – National Energy Technology Laboratory (NETL) – Carbon Sequestration Program and the United States Geological Survey (USGS) – Energy Resources Program – Health and Environment Section – Geologic CO₂ Sequestration Research initiative. These organizations have partnered with a network of regional participants to evaluate CO₂ storage resource potentials in geologic formations throughout the United States and Canada, through the Regional Carbon Sequestration Partnerships program. To date, however, CO₂ storage resource potentials for geologic formations in Massachusetts have not been incorporated into any national or regional carbon sequestration initiative, nor have resources for local geologic carbon storage in Massachusetts been estimated or calculated.

During a preliminary investigation into geologic carbon sequestration potential in Massachusetts, researchers at the University of Massachusetts identified five potential candidate geologic formations for further study. These include: sandstone aquifers in the Connecticut River Valley, unmineable coal seams in southeastern Massachusetts, organic-rich shales in the Connecticut River Valley, basalts in the Connecticut River Valley, and organic-rich metamorphic rocks in the western Berkshire Hills. Through sponsorship from the Massachusetts Clean Energy Center, a project was developed to gain more information about these candidate formations related to their hydrogeologic characteristics and potential carbon storage resource. This information has been used to assess if some or all of these candidates meet screening criteria for geologic carbon storage and to provide data for volumetric carbon storage models as outlined by methodologies developed by the USGS and NETL. This research also has identified gaps in knowledge and information regarding key hydrogeologic characteristics for the candidate formations in Massachusetts. These data are required to determine if formations meet screening criteria and to estimate total storage resources.

None of the five geologic formations currently have sufficient information to ensure viability as carbon storage resources. In particular, a screening criterion of highly saline groundwater (>10,000 ppm total dissolved solids) is required for any proposed underground injection site, yet data on deep groundwater salinities (> 500 meters depth) in Massachusetts are lacking. Comparison with other analogous geologic settings suggests that sufficiently high salinities are likely to be realized in both the Connecticut River Valley sandstones and in unmineable coal seams in southeastern Massachusetts. Information on subsurface geologic structures and basin architecture (such as faults, folds, and overall depths and thickness) can to some extent be inferred from surface outcrops, but true imaging of the subsurface would be required to determine the presence of satisfactory caprock seals to prevent leakage of injected CO₂ from the geologic formations. Inferred anticlines in the coals of southeastern Massachusetts are likely to represent the strongest potential for sufficient caprock, while sandstones in the Connecticut River Valley may also exhibit caprock seals at some locations.

Estimates of formation thickness, areal extent, and porosity for sandstones of the Hartford and Deerfield Basins (Connecticut River Valley) were compiled from published maps and literature, as

well as values drawn from comparison to analogous formations in other geographic settings. Following methods established by NETL for saline aquifers that include estimates of error and efficiency, it is estimated that if sandstones of the Connecticut River Valley meet threshold screening criteria for suitability as CO₂ storage resources (namely salinities above 10,000 ppm TDS and depth sufficient to ensure supercritical CO₂), then these formations could support between 130 and 520 million tons of stored CO₂ depending on subsurface rock porosity, with a more realistic estimate of **130 million tons** storage resource for rocks with 5% porosity. Of this, only a fraction could be targeted for effective CO₂ storage, because much of the land area in the region exhibits intense urbanization and high population density.

Estimates of the formation thickness, areal extent and CO₂ adsorption capacity for coals of the Narragansett Basin (southeastern Massachusetts) were compiled from published maps and literature, values drawn from comparison to analogous formations in other geographic settings and laboratory analysis of adsorption capacity for shaly coal samples collected from the Narragansett basin. Following methods established by NETL for unmineable coal seams that include estimates of error and efficiency, it is estimated that if coals of the Narragansett Basin meet threshold screening criteria for suitability as CO₂ storage resources (namely salinities above 10,000 ppm TDS), then these coals could support **0.1-100 million tons** of stored CO₂ depending on coal thickness, extent and gas adsorption capacity. The samples collected from the Narragansett basin were not pristine anthracite and contained a high ash content yielding a very low adsorption capacity of 35 standard cubic feet adsorbed CO₂ per ton of coal. If the Narragansett coals are all of this variety then the coals could support **0.1 to 1.1 million tons** of stored CO₂.

Based on 2007 estimates of carbon emissions for Massachusetts, available storage in the Narragansett basin and Connecticut Valley will provide approximately 1.5 to 2.5 years of capacity, if all the carbon emissions could be captured. However, capturing carbon emissions from several power plants proximal to the Narragansett basin may provide 3.5 days to 10-16 years of storage depending on the geometry and actual adsorption capacity of the coals. Similarly, if all the carbon emissions from the two power generating plants in the Connecticut Valley were captured, storage capacity in the Hartford basin may exceed 100 years. These lifespan estimates are predicated on the fact that our estimates of the geology and geometry are accurate, that both lateral and vertical seals are available and that the required salinity is achieved in the target formation.

Based on inferred structural relationships, hydrogeologic characteristics, and area/thickness estimates, the other candidate formations (shales, basalts, and metamorphic rocks) are unlikely to represent significant in situ carbon storage resources. However, preliminary experimental results on crushed basalt samples from Massachusetts suggest that CO₂ reacts well with minerals in the basalt to produce stable carbonate precipitate. Results of these experiments will be forthcoming in a supplementary report.

Overall, the areas available for potential CO₂ injection into the subsurface in Massachusetts are small compared with other regions of the country, suggesting that storage resource estimates will be in millions of tons CO₂, yet sufficient storage resource may be realized to offset some small-scale sources of emission.

Chapter Two

Introduction

The following is the final report for the Massachusetts Clean Energy Center to provide a first-order assessment of the feasibility of sequestering CO₂ in geologic reservoirs in Massachusetts. This report presents our current understanding of the geologic reservoirs that exist in Massachusetts and provides preliminary estimates of carbon storage for two geologic reservoirs. It also outlines next steps to be taken in the investigation. New data in this report includes an analysis of coal samples from the Narragansett Basin. These results are incorporated in Chapters 4 and 5. Detailed information on the adsorption capacity of the Narragansett coals can be found in Appendix 1. In addition, the Summary and Recommendations (Chapter 6) have been updated.

2.1 Overview of Carbon Sequestration

Carbon sequestration is the permanent storage of carbon dioxide gas [CO₂] for the purpose of mitigating accumulation of CO₂ in the atmosphere. Carbon sequestration is part of the proposed technique known as carbon capture and storage [CCS], in which CO₂ is separated from other gases and combustion products at a point source such as a fossil fuel-based power plant, transported to a storage location, and injected into deep geological formations (IPCC 2005). Carbon sequestration can be accomplished through a variety of approaches. These include biological/terrestrial storage, injection into deep ocean waters and sediments, and permanent storage in geologic reservoirs. Biological storage relies on removal of atmospheric CO₂ into plant biomass or soil carbon. Ocean storage relies on high pressure found at great depths to convert CO₂ gas into a supercritical liquid. Geological sequestration involves pumping CO₂ into deep underground reservoirs of rock that have the capacity to permanently take up CO₂ (Figure 2.1). This project focuses on the geologic sequestration of CO₂, specifically to develop an assessment of potential CO₂ storage in geologic reservoirs in Massachusetts.

Currently, the five proposed geologic storage sites for CO₂ are deep saline aquifers, oil and gas reservoirs, unmineable coal seams, shales, and basalts. Each of these is associated with geologic features termed sedimentary basins. Sedimentary basins are broad, bowl-like features that result from depression of the earth's crust through the accumulation of thick sequences of sedimentary rocks (including sandstones, shales, and coals), as sediments are shed from eroding mountain ranges. Sedimentary basins may also contain basalts derived from ancient volcanism, as mountain building and volcanism are linked in many geologic settings. Large sedimentary basins may extend for thousands of square kilometers and may be several kilometers thick, while smaller basins are more limited in extent and thickness. Through their geologic history, sedimentary basins may remain intact and stable; this is especially true in the center of continents far removed from tectonic activity. Elsewhere, tectonic activity may lead to sedimentary basins becoming contorted in shape (during subsequent mountain building), altered by heat and pressure to become converted to metamorphic rocks, or uplifted and eroded to a small remnant of their former extent and thickness.

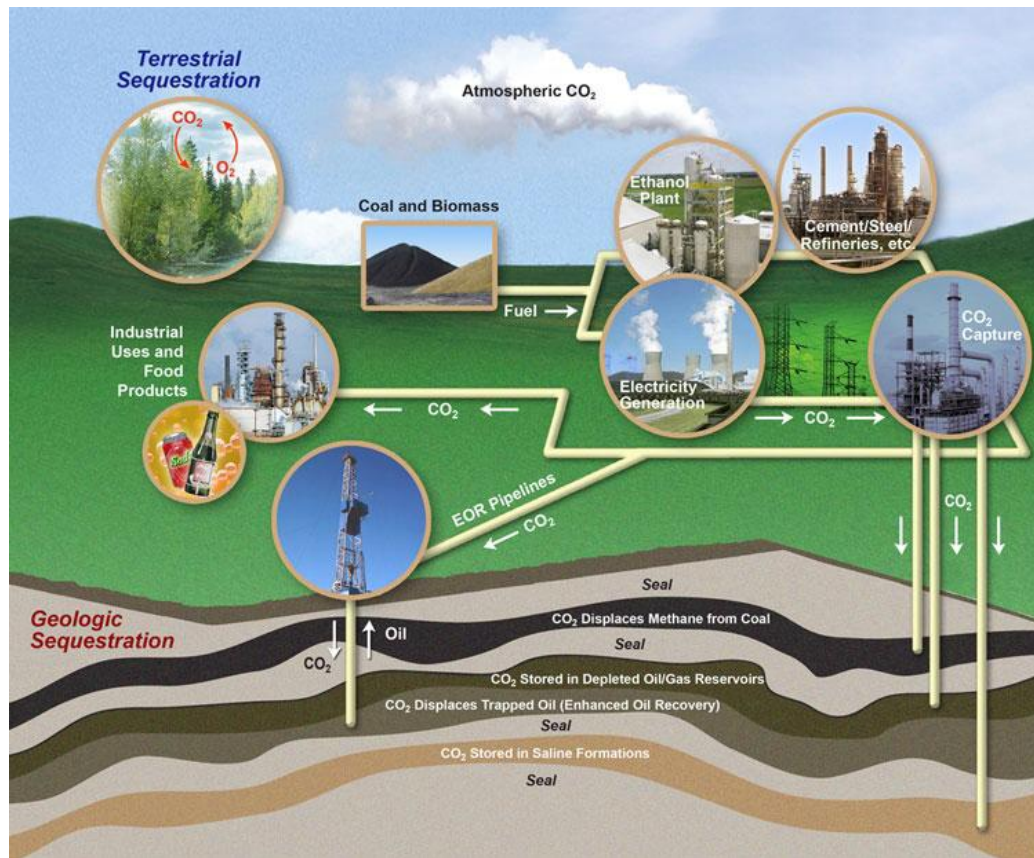


Figure 2.1. Carbon sequestration as a component of carbon capture and storage protocols. From the U.S. Department of Energy – Office of Fossil Energy – National Energy Technology Laboratory - Carbon Sequestration Program website:
www.fossil.energy.gov/images/programs/sequestration/what_sequestration_lg.jpg

One reason that rocks in sedimentary basins are able to take up CO_2 is because of the pore space within their structure. Pore space in a rock is volume that is not occupied by mineral matter, allowing the passage or absorption of fluids. Pore space is quantified by the rock's porosity, or percentage of open pore space in the rock. Unconsolidated sediments have porosities of 50% or greater, while compacted sedimentary rocks typically have much lower porosities of between 5-20%. Crystalline rocks such as basalt have little inherent porosity; porosity in such rocks is highly dependent on fractures that develop subsequent to deposition. Porosity provides a fundamental control on the volume available in a rock for potential CO_2 storage.

Another critical factor in a formation's ability to store CO_2 is permeability. While porosity describes the percentage of open space, permeability describes the connectivity of that space. High permeability indicates that flow of water, CO_2 or other fluids is readily achieved in the rock, while under low permeability flow is more restricted. Permeability provides a fundamental control on the ease with which CO_2 can be injected into a potential storage formation and the ability of the CO_2 to migrate in the formation in response to buoyancy and regional groundwater flow.

In geological carbon sequestration applications, CO_2 is injected into the subsurface at high pressure (approximately 2000 psi). At these pressures, the CO_2 changes from a low-density gas phase to a high-density supercritical phase. With high density, a relatively large mass of CO_2 can be injected into a small volume. When injected into porous media such as rocks in sedimentary basins,

supercritical CO₂ has properties of both gas and liquid. It will dissolve and react with solid substrates like a liquid, yet can diffuse into solids like a gas. In deep basins that contain saline formation water, supercritical CO₂ is less dense than the brine. Thus, CO₂ will migrate upward in a sedimentary basin following injection due to its buoyancy as well as laterally in response to groundwater flow. The upward movement will continue until the plume of CO₂ reaches an impermeable layer called a caprock; if no low-permeability caprock is present above the depth of injection, injected CO₂ will rise until it reaches the Earth's surface. Without an adequate caprock, there is no possibility of permanent carbon sequestration in most geologic settings. There are five different mechanisms by which supercritical CO₂ can be trapped and stored in geologic formations. Many storage sites rely on more than one of these mechanisms:

1. **Structural Trapping** is the result of a caprock overlying the porous rock formation into which CO₂ is injected. This same mechanism results in natural deposits of oil and gas in porous reservoir rocks under an impermeable seal or caprock.
2. **Capillary Trapping** occurs because saline water adheres to mineral surfaces better than supercritical CO₂ does. In large pore spaces connected by narrow channels (common in sedimentary rocks), this can result in a capillary plug of saline water across the channel, trapping CO₂ in the pore space (MacMinn and Juanes, 2009).
3. **Dissolution in Saline Water** is due to the fact that CO₂ is soluble in saline water. The solubility of supercritical CO₂ in water is controlled by temperature, pressure, pH, salinity, and effects of other dissolved components.
4. **Mineralization** occurs when dissolved CO₂ reacts with minerals that are present in the rock formation to form solid carbonate minerals. These reactions are accelerated by elevated temperatures, but still require hundreds to thousands of years to be quantitatively important.
5. **Adsorption of CO₂** takes place in organic-rich reservoirs such as coal, slate, and shales, due to molecules of CO₂ adhering to the solid surfaces of organic matter in the rock. The amount of CO₂ that can be adsorbed onto the rock depends on pressure, the composition of the organic matter, and competition from other gases such as methane or nitrogen.

The geologic storage of CO₂ as a technique to mitigate atmospheric emissions of CO₂ from fossil fuel combustion has gained significant ground in both scientific and policy communities. Currently, geologic storage of CO₂ is being viewed as one of the most significant strategies for dealing with climate change (Hepple and Benson, 2003). While other regions of the United States (and around the globe) have well-developed pilot programs for geologic carbon sequestration, similar programs are lacking for much of the northeastern U.S., including Massachusetts. This is in large part due to an assumption that suitable geologic storage targets do not exist in sufficient volume to support significant carbon storage and to mitigate local/regional carbon emissions. However, an accurate assessment of the carbon storage resource potential has not been constructed for Massachusetts, and thus the capacity for any amount of carbon storage remains undefined. As such, the purpose of this project is to create a first order assessment and characterization of possible storage sites in Massachusetts.

2.2 Scope of Project

Five possible targets for geologic carbon storage in Massachusetts have been identified (Figure 2.2). These targets are:

1. Deep sandstone aquifers in the Connecticut River Valley
2. Organic-rich shales in the Connecticut River Valley
3. Unmined coal seams in southeastern Massachusetts
4. Deep basalts in the Connecticut River Valley
5. Organic-rich schist and slate in the Berkshires.

The National Energy Technology Laboratory (NETL) Carbon Sequestration Program has developed calculations which provide CO₂ storage capacity estimates for a given storage site. Much of the information required to develop a complete assessment of the CO₂ storage potential in Massachusetts is currently not available. As such, exploring existing data and conducting analysis on rock types that are representative of each possible storage site will be the primary tools to recover the required information for these calculations. New analyses will provide key quantitative measures of rock properties that will prove fundamental for subsequent calculations of carbon storage potential estimates. Also, comparisons across analogous geologic settings may reveal information that could supplement unavailable data that is necessary for future capacity assessments in Massachusetts.

2.3 Organization of Project

This project consisted of four reports. The first product was a survey report produced from data mining that showed what information is known about each potential target site in Massachusetts. This information determined what data are necessary to attain from analogous basins.

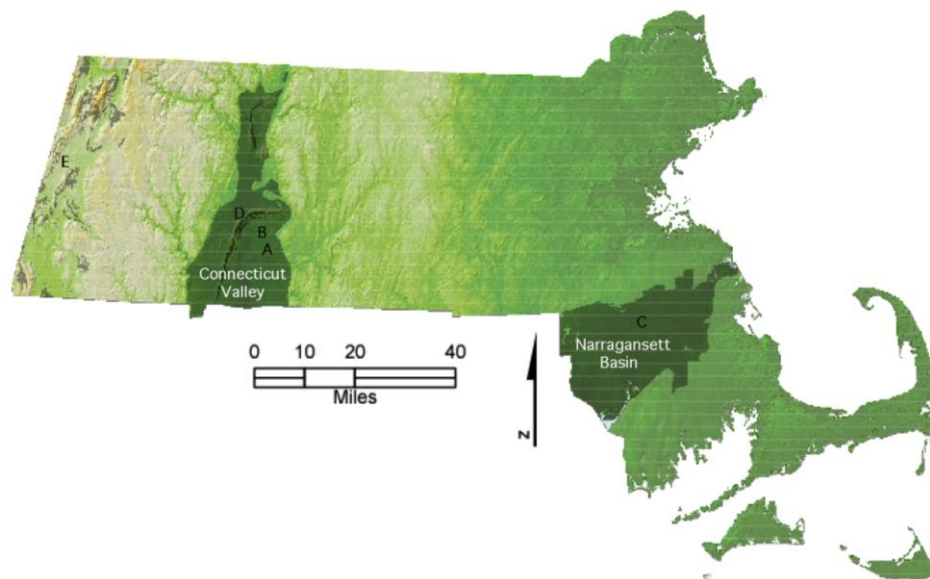


Figure 2.2. Map showing general areas (gray areas) where potential targets for geologic carbon sequestration in Massachusetts might be possible. These include: A) deep saline aquifers in the New Haven arkose and Sugarloaf arkose in the Connecticut Valley; B) Organic rich shales in the Connecticut Valley; C) unmineable coal beds in the Narragansett basin; D) deep basalts in the Connecticut Valley; and, E) carbon-bearing graphitic schists in the Berkshires.

The second report provided a preliminary assessment of the CO₂ storage resource potential at two of the five target areas in Massachusetts. Where data mining and new analyses provided data, these were directly input into the calculation models. Where information was uncertain or lacking, range estimates complete with full error analysis were applied.

In the third report a chapter on implication of results was added to help identify next steps in the study, determine if further research on CO₂ storage in Massachusetts is justified and identify approximate costs for additional research.

The fourth and final report (this report) adds new data to the storage estimates in the Narragansett basin. During the summer of 2010, samples of coal from the Narragansett basin were obtained and analyzed for adsorption capacity. This new data was modeled and is included in this final report. This new data is incorporated in Chapter 5.

2.4 Schedule

Report No. 1 – February, 2010

Report No. 2 – May, 2010

Report No. 3 – June, 2010

Report No. 4 – May 15, 2011

Chapter Three

Geologic Carbon Storage

3.1 General Site Selection Criteria

What is necessary for a good storage reservoir?

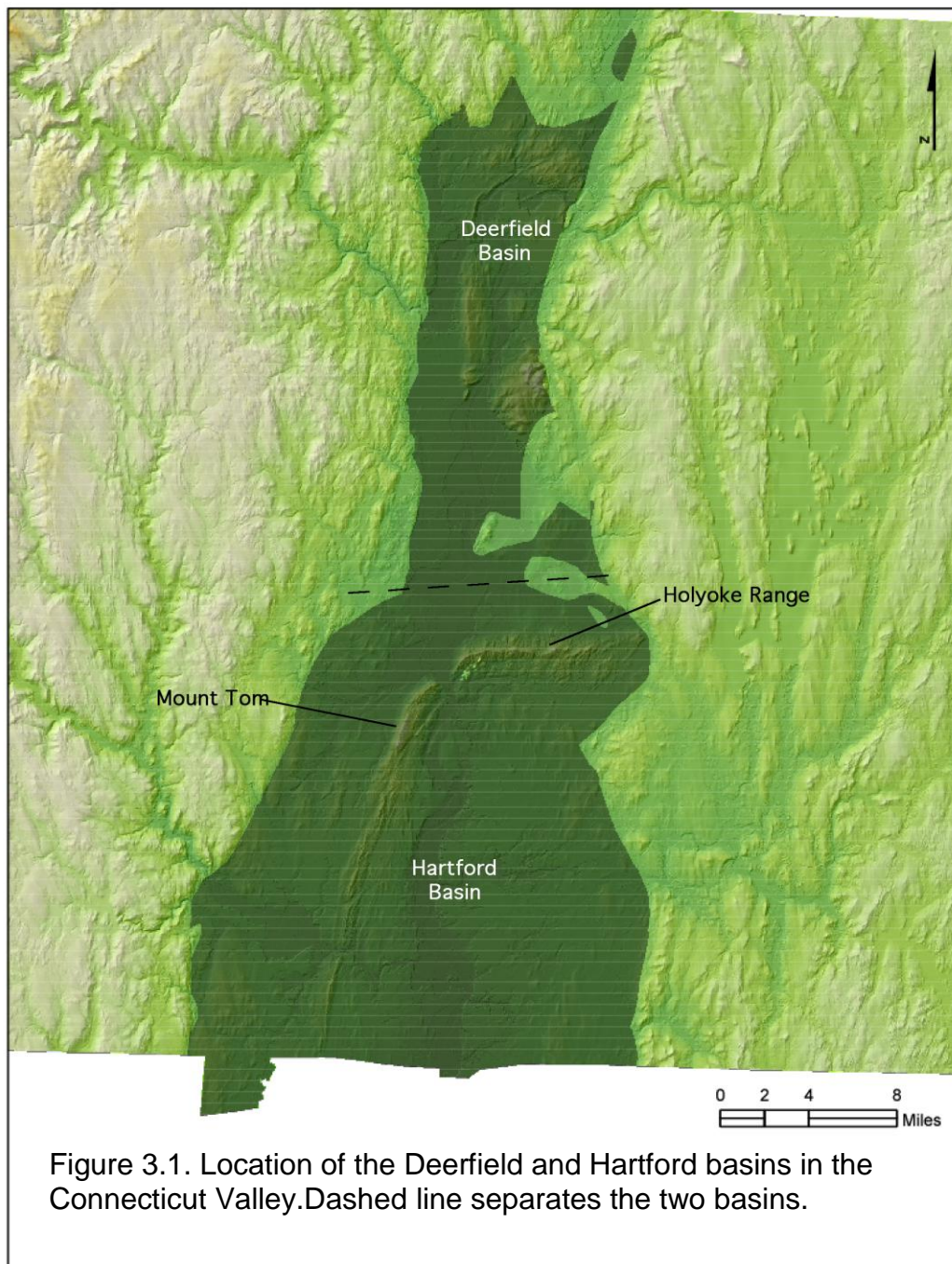
For a geologic basin to be considered as a possible storage reservoir for CO₂ it should meet the following criteria.

1. Adequate capacity to hold the proposed amount of CO₂
2. Ability to withstand an established rate and pressure of fluid to be pumped into the rock unit without damaging (fracturing) the unit (Injectivity)
3. Presence of a caprock directly above the unit which would aid in restricting movement of CO₂ in the vertical direction
4. A geologic environment that lacks features that would render it unstable, such as faults or hydrothermal activity.

3.2 Deep Saline Aquifers

a. Description

Deep saline aquifers are porous rocks, such as sandstone, in which pore spaces are filled with high-salinity waters. These types of formations are widespread. However, they are unsuitable as a source of water for agriculture or human consumption due to the high concentration of salt (IPCC, 2005). Thus, high salinity ensures that no fresh water resource would be impacted by carbon storage. At depths greater than approximately 800 meters (3000 feet), pressures from the overlying rock (lithostatic pressure) are great enough that CO₂ is stable, not as a gas, but as a high-density supercritical fluid. Due to the amount of pore space in these aquifers, it is possible to store a large amount of supercritical CO₂ within the pore space. However, in order to prevent upward migration of CO₂ in the aquifer, a caprock or impermeable seal must be located above the aquifer. In addition, injection of CO₂ into the pore space displaces the brine forcing it to migrate. The brine may begin to displace fresh water. The environmental risk of brine displacement is dependent somewhat on the hydraulic conductivity between the deep storage unit and any overlying fresh water resource. Thus, in characterizing a given basin, it is important to understand the hydrological properties associated with that basin.



b. Location

There are two sedimentary basins located in the Connecticut River Valley in western Massachusetts. The northernmost basin is the Deerfield Basin and the southernmost basin is the referred to as the Hartford Basin (Figure 3.1). Both are part of a larger chain of exposed sedimentary basins that extend along the eastern margin of North America from Nova Scotia to North Carolina, with subsurface basins extending further north into Newfoundland, south into Florida and the Gulf of Mexico, and seaward to the edge of the North American continental shelf (Figure 3.2). These basins

formed as a result of crustal extension when the North American continent separated from the African continent to form the present-day Atlantic Ocean during the Middle- to Late Triassic, about 250 million years ago (Froelich and Robinson, 1988).

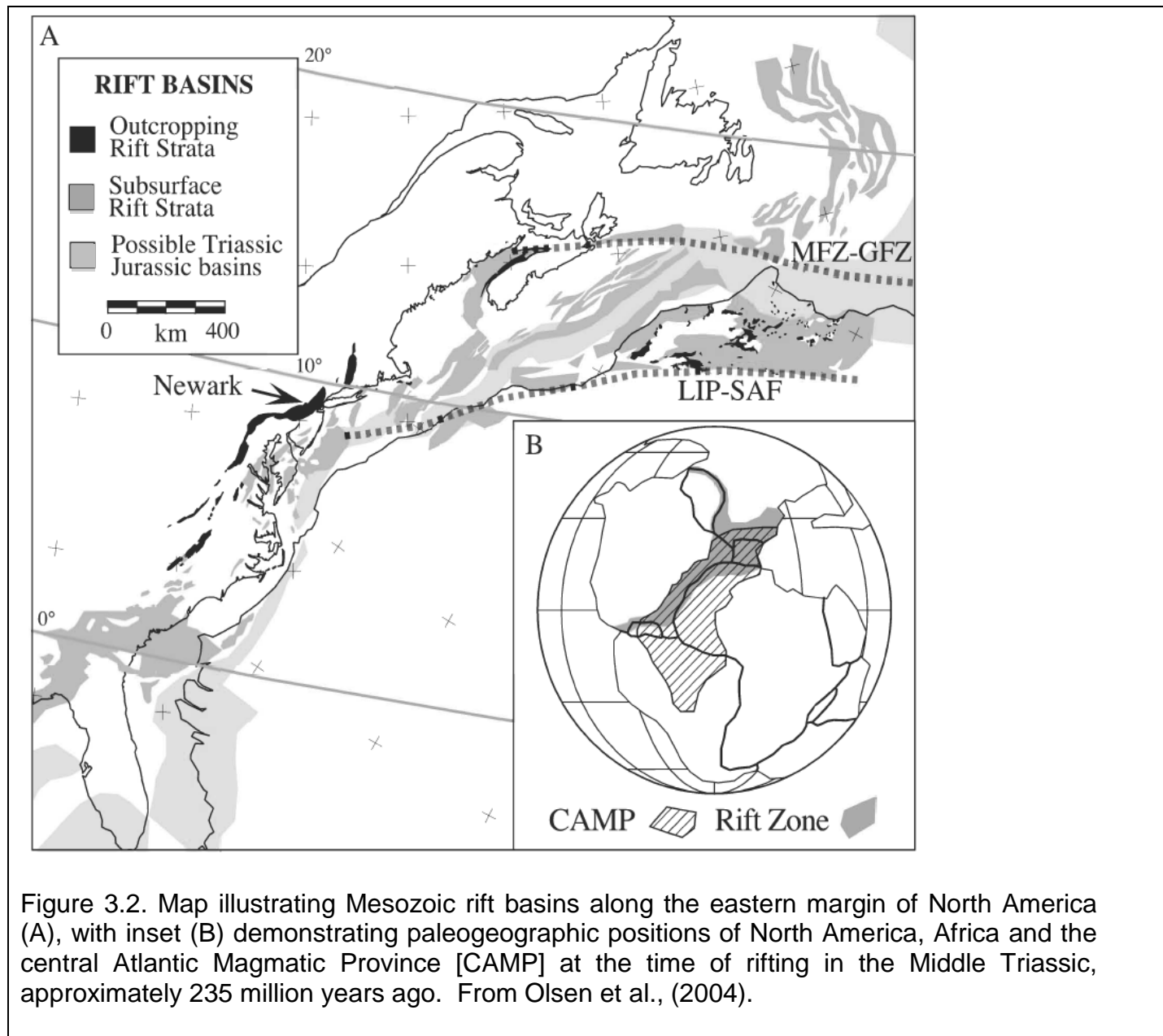


Figure 3.2. Map illustrating Mesozoic rift basins along the eastern margin of North America (A), with inset (B) demonstrating paleogeographic positions of North America, Africa and the central Atlantic Magmatic Province [CAMP] at the time of rifting in the Middle Triassic, approximately 235 million years ago. From Olsen et al., (2004).

The Deerfield Basin trends north-south and averages 5 km (3 miles) wide by 25 km (15 miles) long (Taylor, 1991). The Deerfield Basin comprises five formations (Figure 3.3). The oldest and deepest formation is the Sugarloaf Arkose. This formation is composed of fluvial sandstones (also known as red beds due to their red coloration from abundant iron mineralization) and is between 1600 meters (5280 feet) and 2370 meters (7800 feet) thick. Above the Sugarloaf Arkose are the Fall River Beds. These beds are 3 to 9 meters (10 to 30 feet) thick and are black organic-rich shales. These are low permeability rocks that could serve as a potential caprock. The Fall River Beds are overlain by the 120 meter (394-foot) thick Deerfield Basalt. This is a lava flow that flowed over the surface of the

basin from rifts and vents created during the extension of the basin. The basalt consists of several flows that contain vesicles and openings in the upper part of the flow and individual flows at the surface often show columnar jointing. These are vertical joints that exhibit a characteristic hexagonal pattern on the surface and form as a result of cooling. The joints provide an excellent vertical pathway for fluids. The basalt is overlain by the Turners Falls formation that is between 90-1300 meters (295-4265 feet) thick. The Turners Falls formation comprises interbedded fine-grained sandstones and shales. The youngest formation in the Deerfield Basin is the 300-1000 meter (984-3280 foot) thick Mt. Toby Conglomerate. Although this unit is slightly younger than the Turners Falls Formation it is interbedded with the Turners Falls Formation. The surface distribution of these rocks is shown in Figure 3.4 and a generalized cross section shown in Figure 3.5.

The Hartford Basin is contiguous with the Deerfield Basin in central western Massachusetts (Figure 3.1). Most of this basin is in Connecticut, but the northern portion (some 25 km (15 miles) wide and 30 km (19 miles) north-south) occupies the southern portion of the Connecticut River Valley in Massachusetts (Figure 3.1). The Hartford Basin exhibits a more complicated stratigraphy than the Deerfield Basin, with a 1830-meter (6000foot) thick New Haven Arkose at its base (roughly equivalent to the Sugarloaf Arkose in the Deerfield Basin), three basalt layers (Talcott, Holyoke and Hampden basalts, each approximately 91 meters (300 feet) thick) interbedded with two formations comprising shales and sandstones (the Shuttle Meadow and East Berlin Formations), topped with the approximately 2435-meter (8000foot) thick Portland Formation containing sandstone, shales and conglomerate. Figure 3.3 shows the relationships between named formations in the Hartford Basin with those of the Deerfield Basin.

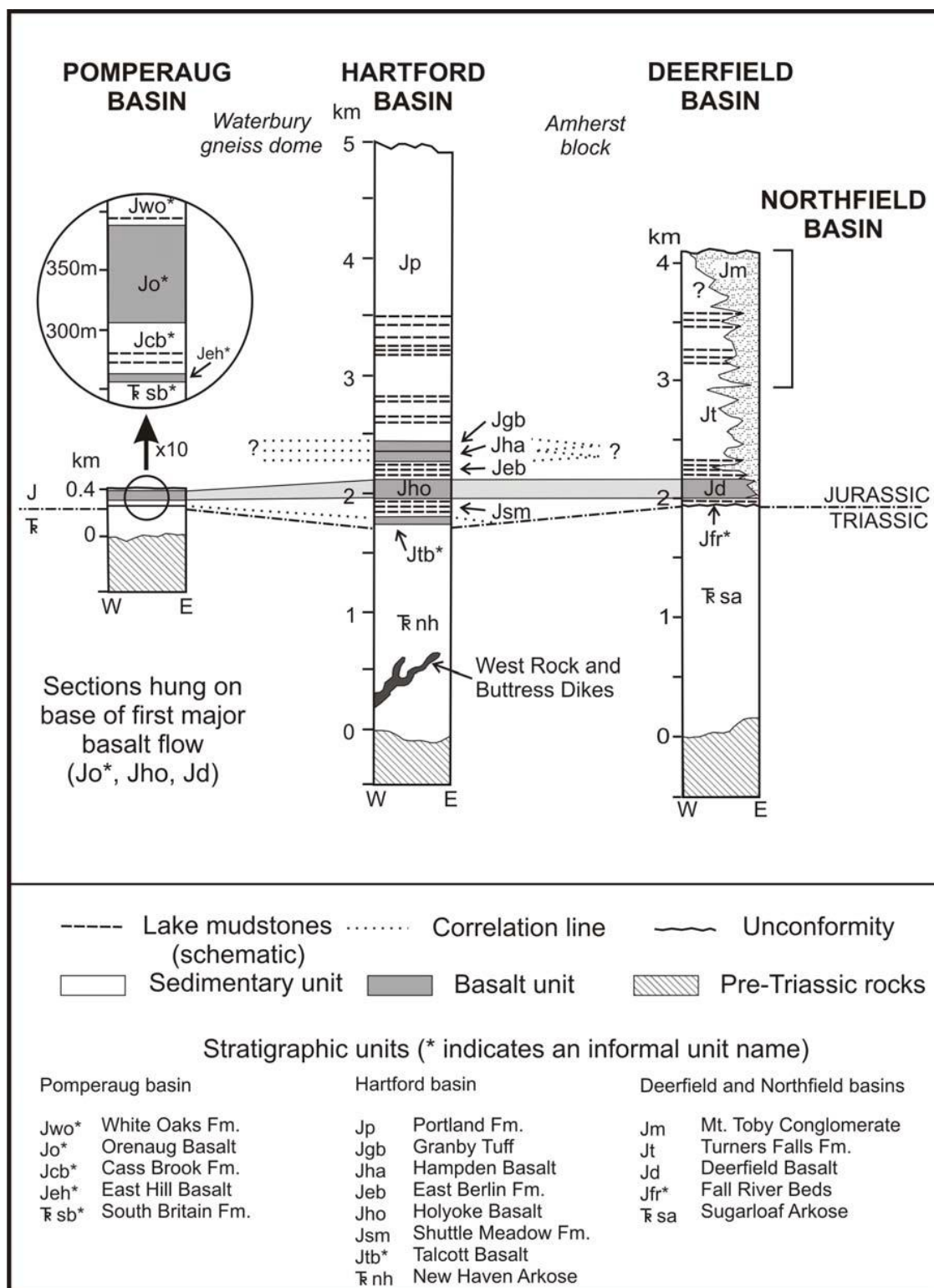


Figure 3.3. Stratigraphic columns of the Deerfield, Hartford and Pomperaug Basins (from Walsh, 2008) and compiled from references therein.

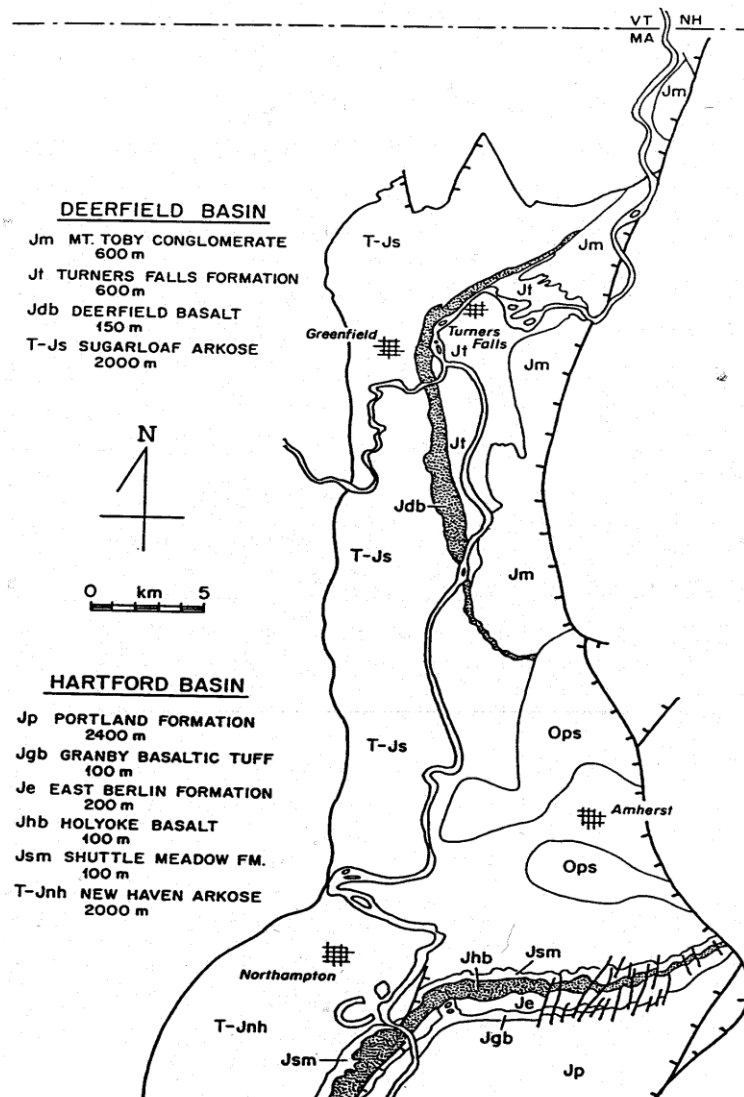


Figure 3.4. Map showing the distribution of the geologic units in the Deerfield Basin and the Hartford Basin in Massachusetts. The dividing line between the two basins is approximately along the line connecting Northampton and Amherst. Note: the Fall River Beds although present are not a mappable formation at this scale. From Hubert et al., (2001).

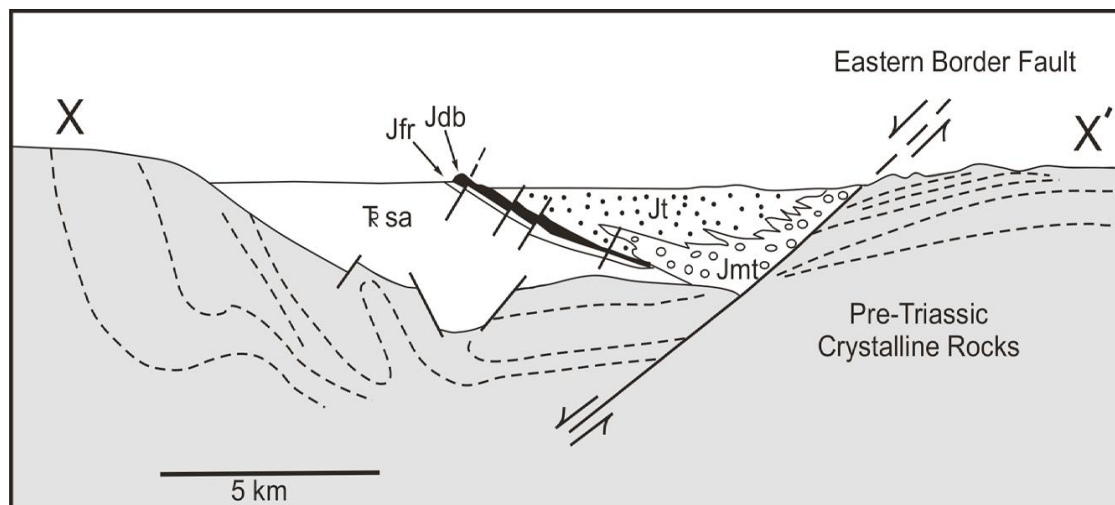
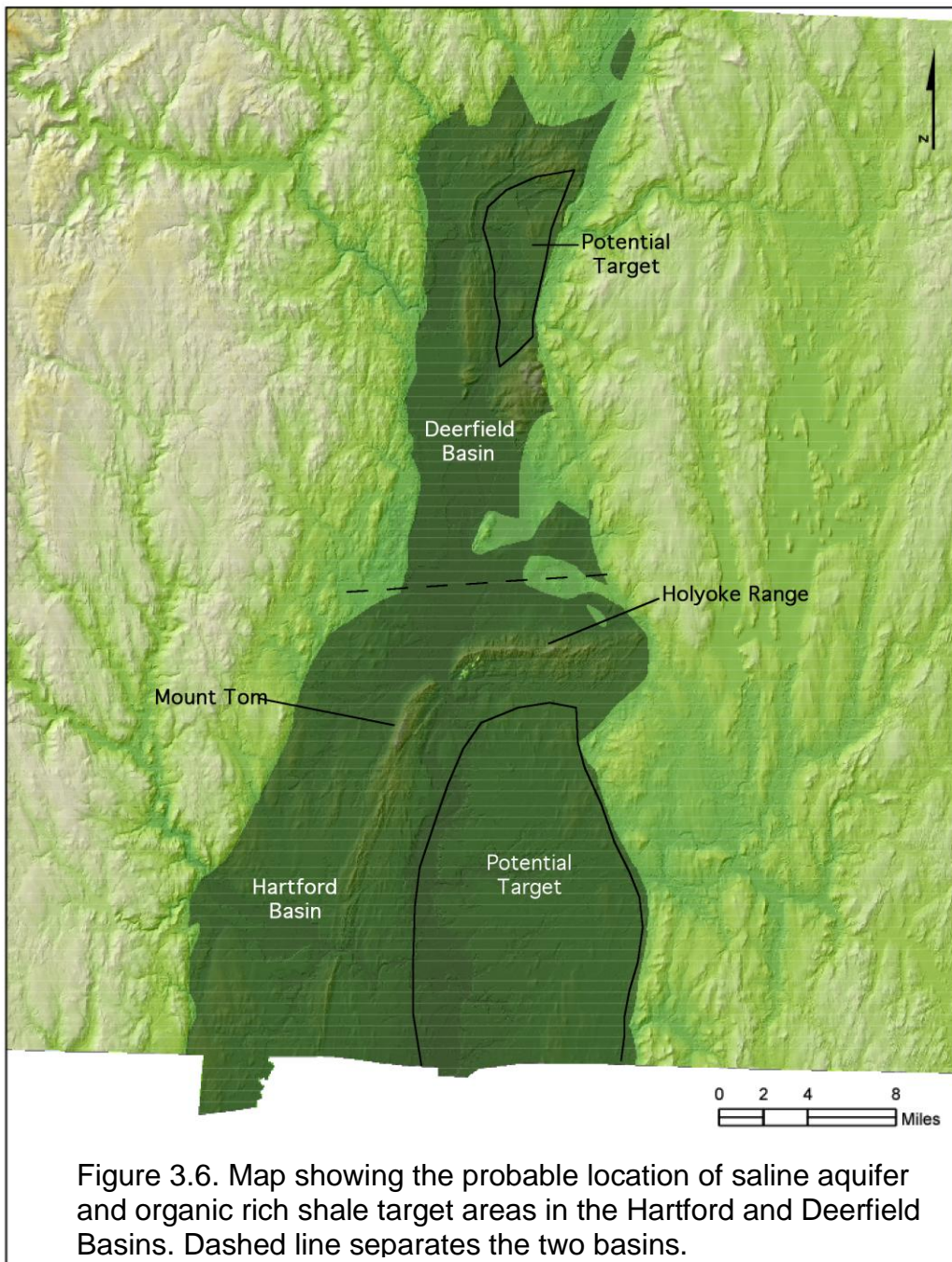


Figure 3.5. Generalized cross section of the Deerfield Basin showing the juxtaposition of units in the subsurface. The Eastern Border Fault controlled the formation of the basin but numerous smaller faults are observed in surface exposures, especially in the Deerfield Basalt and adjacent strata. From Walsh (2008).

Although initially deposited as horizontal, flat-lying strata of sediments, tectonic activity along the eastern border fault of the Deerfield and Hartford Basins approximately 200 million years ago caused these strata to dip to the east. The oldest strata (Sugarloaf Arkose in the Deerfield Basin and New Haven Arkose in the Hartford Basin) dip most steeply (up to 20° but can be as steep as 45° near the margin), while the youngest strata (uppermost Mount Toby and Portland formations) are nearly flat-lying. For this reason, outcrops of the oldest strata along the western sides of these basins extend downward and eastward towards the eastern border fault (Figure 3.5). In the absence of information regarding faults and other structures in the subsurface of these Basins, it cannot be determined if the arkose units are continuous from the surface down and east into the deep center of the basins, or if there are structural traps that would provide caprocks to prevent migration of fluids such as injected CO_2 .

The faulting and downwarping of the crust allowed sediments to accumulate rapidly in the basins. In general, the sediments are coarsest within 4 km (2.5 miles) of the eastern margin and become finer toward the west. Thus, the hydraulic conductivity and porosity will be optimum in the region nearest the eastern border. In addition, the thickest shale units (caprocks) are located within 1.5 km (1 mile) of the border fault. Lakes that are necessary to form the shale units apparently persisted longer and were possibly deeper near the eastern margin (LeTourneau, 1985).

In the Deerfield and Hartford Basins, the lower-most arkosic sandstones represent potential targets for geologic carbon sequestration (Figure 3.6). This is because these formations are most likely to contain adequate porosity and permeability for carbon injection and storage capacity (unlike the shales), are most likely to be deeply buried enough to support supercritical CO_2 (unlike shallower units), and are most likely to currently contain saline formation waters (although at present, the salinity of any brines at depth in these basins remains unknown).



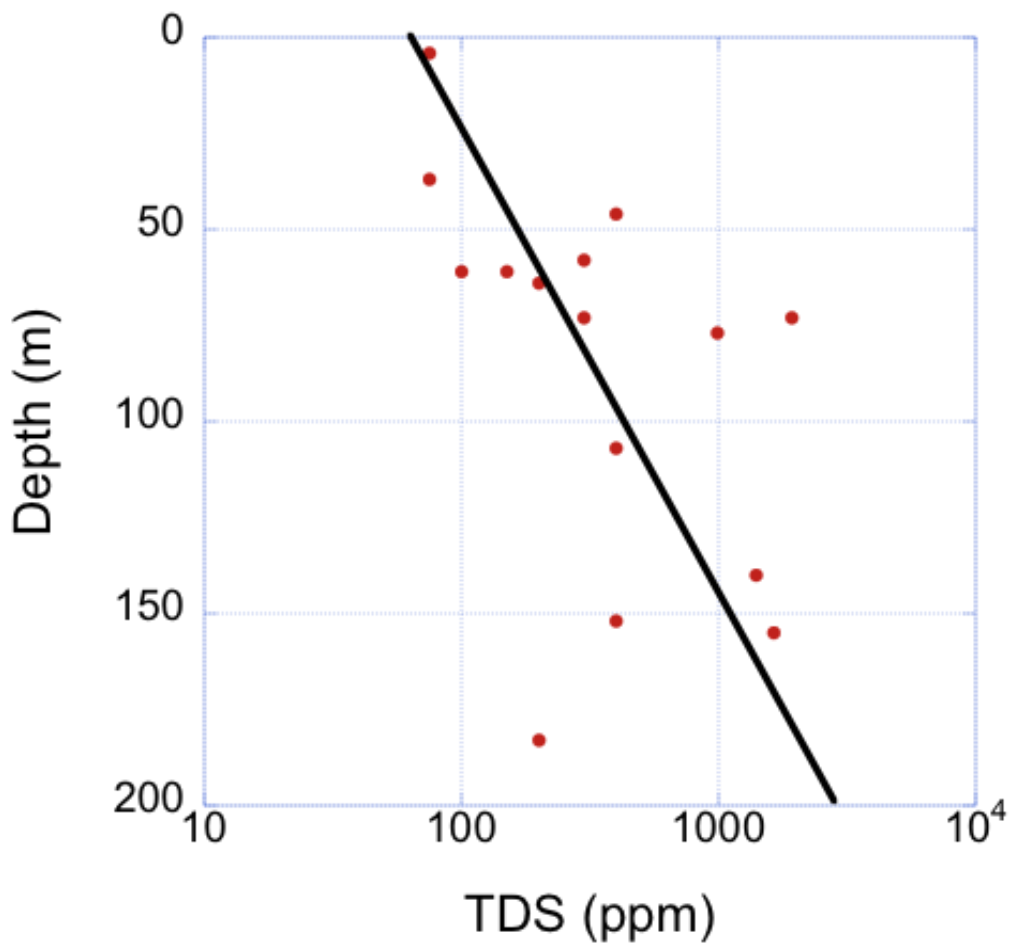


Figure 3.7. Measured TDS concentration in shallow (<200 meters) depths in the Hartford and Deerfield Basins. A weak linear correlation is observed, suggesting a source of highly saline brines at depth mixing with shallow, dilute precipitation-derived groundwaters. Based on this observation, saline brines (TDS > 10,000 ppm) are likely to occur at depths greater than 400 meters in the Hartford and Deerfield Basins. Data from Wandell and Caswell (1977).

The critical factors that will determine the feasibility of these basins for carbon sequestration will be the availability of a caprock or some other structural trap to contain the CO₂ and the depth at which formation water achieves a total dissolved solids concentration of 10,000 mg/l. A preliminary review of existing well data in the Connecticut Valley shows a general trend of increasing dissolved solids load with depth but the number of wells available is limited (Figure 3.7). Extrapolation suggests reaching 10,000 mg/l at a depth of greater than 260 meters (850 feet) but examination of other analogous basins or direct sampling are needed. Another concern is the dip of the beds. If there is no structural feature or low permeability zone, there is no caprock seal to stop CO₂ migration upward to the west along bedding planes in the arkose.

3.3 Organic Rich Shales

a. Description

Shales are fine-grained sedimentary rocks, typically exhibiting low permeability and porosity. Along with fine-grained mineral grains, shales commonly contain ancient organic matter derived from remains of terrestrial plants and algae. With elevated temperatures and pressures of deep burial in sedimentary basins (termed maturation), the composition of this organic matter is altered, and oil and/or natural gas may be driven off. Organic-rich shales present opportunities for carbon sequestration through adsorption of supercritical CO₂ onto the surfaces of sedimentary organic matter. Oil and gas formation may also be accompanied by generation of secondary porosity (porosity that develops long after burial and compaction of the sediment), enhancing capacity for CO₂ uptake. Carbon injection into oil and gas fields is a long established technique for enhancing gas and oil recovery, as CO₂ molecules adsorb onto the organic matter, replacing and liberating greater amounts of oil or gas. Organic matter content and quality declines with extensive thermal maturity, limiting the capacity of shales to adsorb CO₂ and the possibility for enhanced oil and gas generation. CO₂ adsorption capacity is characterized by a parameter termed the adsorption isotherm. The CO₂ adsorption isotherm, in units of standard cubic feet CO₂ (scf) per ton, in shales ranges between low values of less than 50 scf/ton for mature shales or shales poor in organic matter (<1% total organic carbon (TOC) by weight), to rare values of greater than 100 scf/ton for immature shales that are rich in organic matter (>5% TOC).

b. Location

Several black, organic-rich shales are found within strata of the Deerfield and Hartford Basins, specifically within the Shuttle Mountain, Portland, East Berlin Formations of the Hartford Basin, and the Fall River Beds and Turners Falls Fm. of the Deerfield Basin. These shales are uniformly thin (1-3 m (3-10 feet) thick, thicker for the Fall River Beds and Shuttle Mountain Formation), but are capped and bound by other shales, presenting the possibility of sufficient caprock to support permanent CO₂ sequestration (Figure 3.3). Shales in the northern portion of the Deerfield Basin are the most carbon-poor and most thermally mature, indicating poor capacity for CO₂ adsorption, while shales in the Hartford Basin are both more organic-rich and of lower maturity (Hubert et al., 1992). Due to overmaturity (in the Deerfield Basin) and limited capacity for oil generation (in the Hartford Basin) none of the shales in these basins has been exploited for oil and gas production; thus no network of existing oil and gas wells for targeted CO₂ injection is available. Adsorption isotherms are not presently available for these formations, but when obtained will reveal the capacity of these rocks to store CO₂. The areas that show the most promise for organic-rich shale carbon sequestration are located along the eastern side of the Hartford and Deerfield basins (Figure 3.6).

3.4 Unmineable Coal Seams

a. Description

Coal seams that are too deep and/or too thin to be mined economically are termed unmineable coal seams. The geologic storage of CO₂ in unmineable coal seams relies on the adsorption of the CO₂

on the coal and the permeability of the bed. The adsorption of CO₂ in coals is thus similar to adsorption in shales. Carbon sequestration in coals is commonly associated with enhanced coal-bed methane recovery, in analogy with enhanced oil/gas recovery from shales. The capacity for coals to adsorb CO₂ expressed as adsorption isotherms is much greater than in shales, ranging between 500-2000 scf/ton. Thermal maturity of coals impacts coal composition and structure, and leads to decreases in CO₂ adsorption capacity, although not as severely as with thermally mature shales.

b. Location

Coal-bearing rocks in southeastern Massachusetts and Rhode Island occur in the 2486 km² (960 square miles) Narragansett Basin (Figure 3.8). The basin is about 58 km (36 miles) long by 24 km (15 miles) wide, on average.

The Narragansett Basin supported limited coal mining during the nineteenth and twentieth century predominantly occurring in Portsmouth, Rhode Island and Mansfield, Massachusetts with the last mine in Cranston, RI, closing in 1959 (Skehan et al., 1981). The reported uses of the coal included industrial fuel for copper smelting and heating greenhouses, a carbon raiser in steel batches, and an oxygen scavenger in foundries (Barton et al., 1977). After World War II the Bureau of Mines carried out a limited investigation concerning the coals of the Narragansett Basin. It was concluded that mineable coal might exist but that it could not compete with the fuels on the market at the time, thus no further investigation was warranted (Skehan et al., 1981). However, as petroleum prices increased in the 1970s, interest in the coal of the Narragansett Basin was renewed and a major investigation was conducted involving the State Geologists from both Massachusetts and Rhode Island, the Bureau of Mines, the Federal Energy Administration (now the Department of Energy), the National Science Foundation and Boston College.

The Narragansett Basin is a complex structural depression containing elaborately folded and faulted rocks where the major fold axes trend toward the north in RI and curve to the northeast in MA (Shaler et al., 1899; Skehan et al., 1981). The basin formed in a similar fashion to the Hartford and Deerfield Basins but developed much earlier, beginning approximately 320 million years ago. The basin is fault bounded on the north and south sides and formed through extension of the crust just prior to the collision of the African-Iberian continent with North America. The depositional environment during this extensional period was rapid fluvial sedimentation with numerous lake and swamp environments that eventually formed the organic shales and coals observed today. Because the lakes and swamps were small, sporadic and transient, the location and extent of the coal is difficult to predict (Frimpter and Maevsky, 1979).

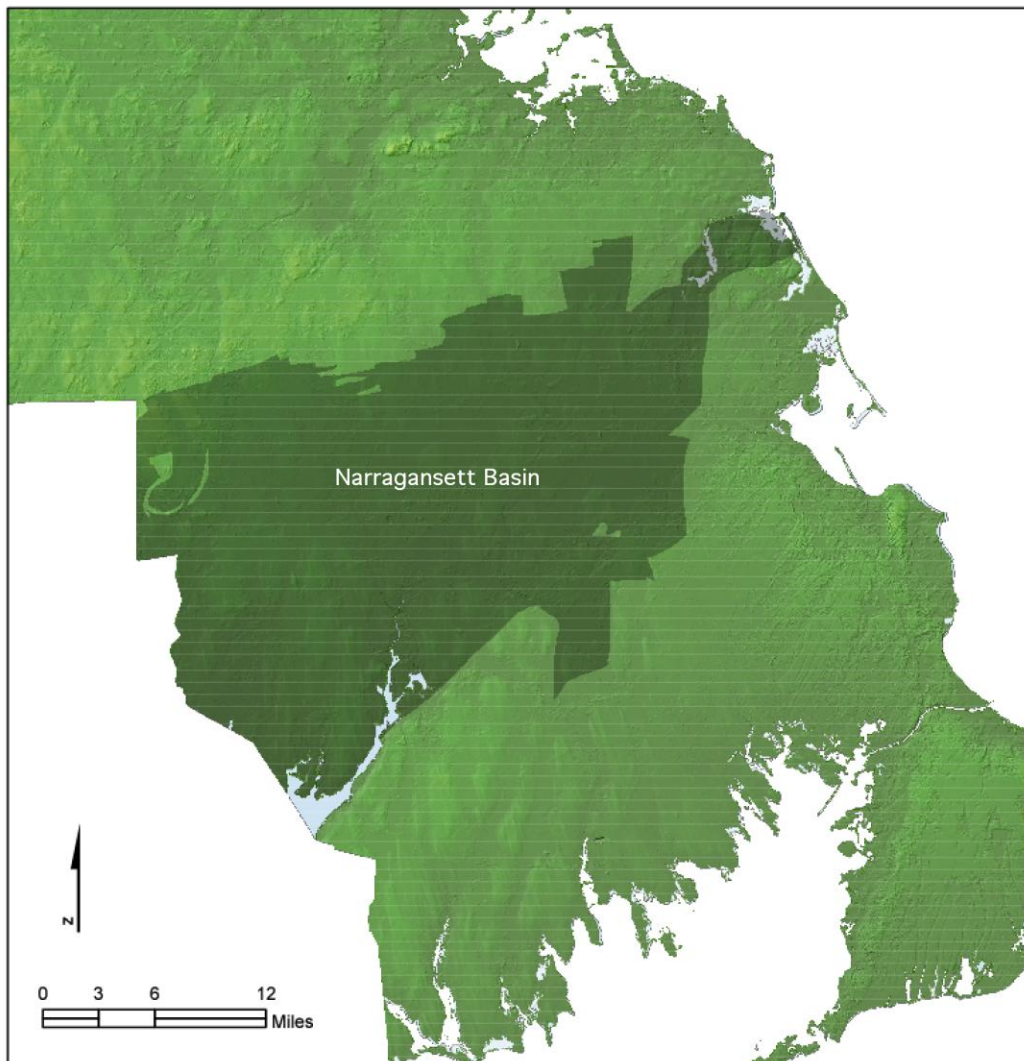


Figure 3.8. Location of the Narragansett Basin. Faults border the north and south edges of this extensional basin formed about 320 million years ago.

Within the basin are four stratigraphic units; the Pondville Conglomerate (458 meters (1500 feet) thick) at the base, the Wamsutta Formation (1525 meters (5000 feet) thick), the Rhode Island Formation (3660 meters (12,000 feet) thick) (coal bearing formation) and the Dighton Conglomerate (427 meters (1400 feet) thick). The Rhode Island Formation is described as being interbedded pebbly conglomerate with siltstone, mudstone, shale and coal (Lyons, 1977). The coal, which is found in the Rhode Island Formation, is discontinuous and of variable thickness (Skehan et al., 1981).

During the collision of the African-Iberian continent with North America approximately 290 million years ago the basin and sediments were folded into a series of moderately-dipping anticlines and synclines (Figure 3.9) with fold axes trending east northeast. Thus, the coal seams are not flat lying but tilted. The rocks were also metamorphosed converting shales to slates and phyllites and the swamp deposits to anthracite-grade coal (Frimpter and Maevsky, 1979). The degree of metamorphism is highest in Rhode Island and decreases toward the northeast in Massachusetts. The sedimentary rocks are highly indurated. However, primary porosity remains relatively high but poorly connected leading to fairly low permeability (Frimpter and Maevsky, 1979).

In addition to the basin bounding faults there are many north-south trending cross faults that show offsets ranging from 610 meters (1970 feet) to 7625 meters (25,000 feet) (Lyons, 1977). These post-date the folding in that many of the folded rocks are cut by these faults. East-west trending faults are also apparent and show oblique dip slip motion, a combination of extension and strike slip motion. Thus, the position and extent of coal beds is complicated in part by displacement along these faults (Figure 3.10).

Frimpter and Maevsky (1979) conducted geophysical logging and water quality testing on 13 wells drilled as part of the Department of Energy investigation conducted by Weston Observatory under the direction of Father James W. Skehan S.J. at Boston College in the 1970s. The depth of the wells in their study ranged from 100 meters to 457 meters (330 feet to 1500 feet). Results of the geophysical logging confirmed that the coal seams are thin and discontinuous. However, there are no data available below 457 meters (1500 feet).

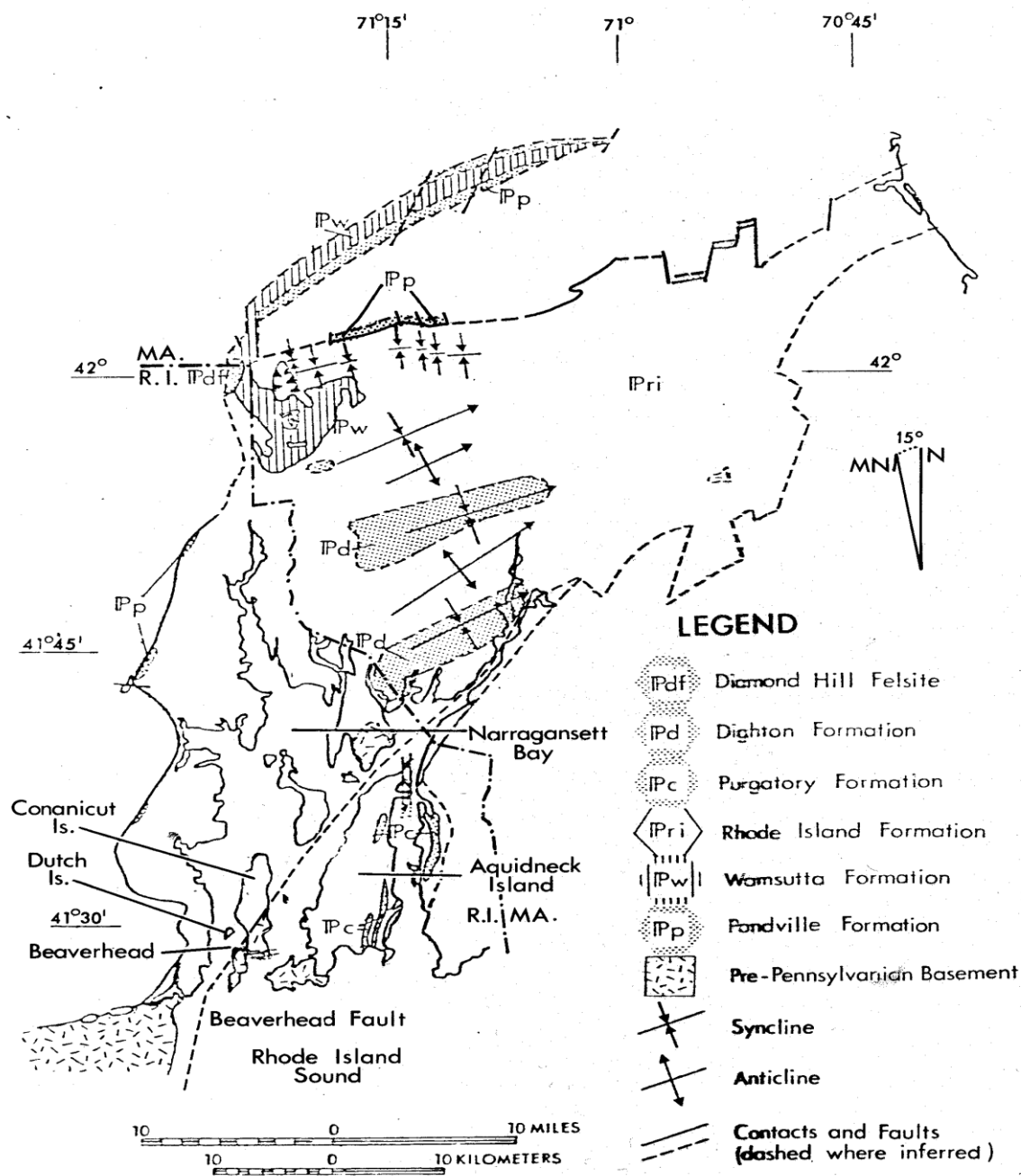
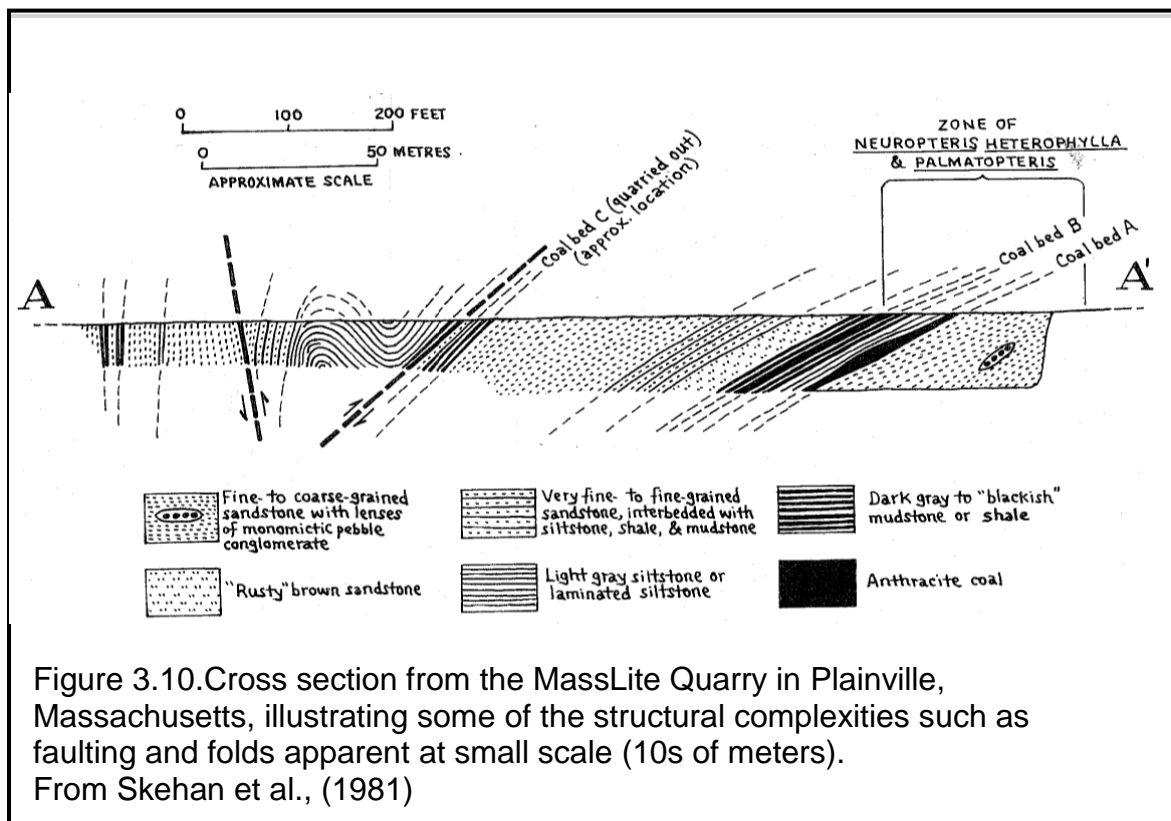


Figure 3.9. Generalized geologic map showing the location of anticlines and synclines within the Narragansett Basin. Offsets along the north border of the basin are caused by the north-south cross faults. The Pri unit is the Rhode Island Formation (from Skehan et al., 1981)

Water quality data are lacking also. Frimpter and Maevisky (1979) also measured specific conductance in the wells drilled by Skehan and colleagues, and found the range to be 100 to 530 microsiemens per centimeter. These are all within the range of water with very low total dissolved

solids. However, these are all shallow wells and represent conditions in the top 152 meters (500 feet) of the crust.



3.5 Deep Basalts

a. Description

Basalt is a geological formation of igneous rock, in contrast to the sedimentary rock formations proposed for other carbon storage reservoirs and outlined in the *2008 Carbon Sequestration Atlas of the United States and Canada, 2nd edition*. Basalt is the result of solidified lava flows at earth's surface as well as injection of lava as horizontal sheets and vertical intrusions. Individual flows and intrusions typically are only a few meters thick, but repeated volcanic eruption and magmatic activity can build up thick sequences of basalt that can be 10s to 100s of meters thick or greater. Basalt is made of mafic minerals, that is, minerals that are rich in iron, magnesium and calcium such as anorthosite (a plagioclase feldspar), pyroxene, amphibole and olivine. These minerals can react with CO₂ under elevated pressures and temperatures, consuming the primary minerals and generating new carbonate minerals such as calcite. Naturally-occurring reactions between basalt and dissolved CO₂ develop along mid-ocean ridges in seafloor hydrothermal systems. Artificial reactions of basalt minerals with CO₂ have also been demonstrated (McGrail et al., 2006), thus leading to basalts being proposed as potential permanent CO₂ storage reservoirs.

b. Location

The basalts located in the Deerfield and Hartford Basins are being explored as possible storage sites for CO₂. As described in the above section on deep Saline Aquifers, there is one major basalt flow in the Deerfield basin (Deerfield Basalt) and three large basalt flows in the Hartford Basin (Talcott, Holyoke and Hampden). The Deerfield basalt is about 120 meters (394 feet) thick and each of the basalts in the Hartford Basin average about 91 meters (300 feet) thick. The Deerfield basalt is pillowed (indicating it flowed into water) and vesicular (full of voids and openings) at its base whereas the upper portion of the basalt flow is strongly jointed. The basalts outcrop mostly in the center of the basin and form ridges due to their resistance to weathering. Approximately 52 km² (20 sq. miles) of basalt is exposed in the two basins (Figure 3.11) The basalts also dip to the east and south at 10° to 15° degrees. Therefore, the possible target areas lie in the deeper regions of the basin to the east (Figure 3.11).

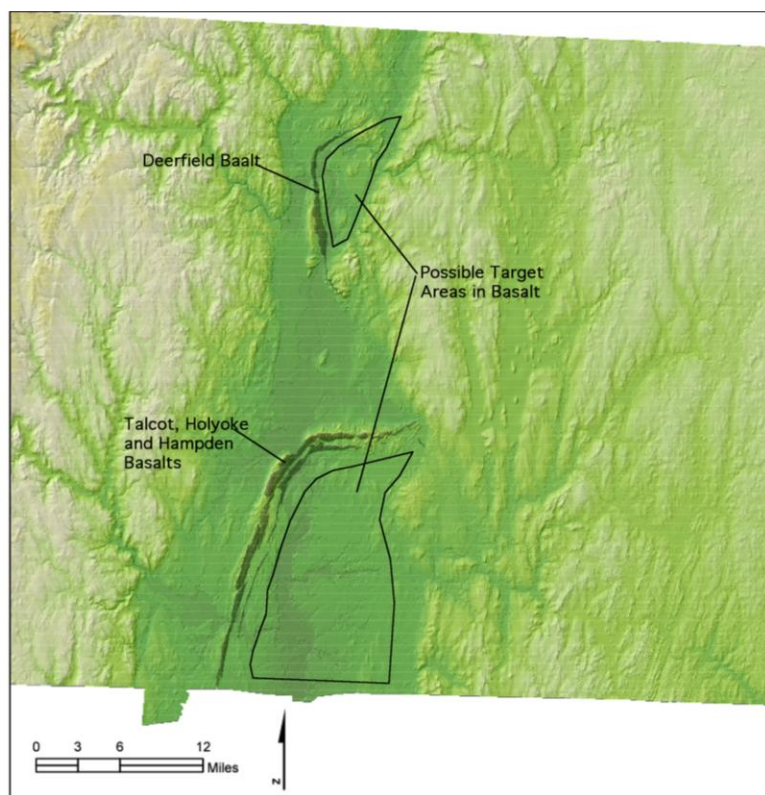


Figure 3.11. Location of basalt flow exposures in the Hartford and Deerfield basin in the Connecticut River valley, western Massachusetts. Units dip to the east. Possible subsurface target areas shown by black outlined polygons.

3.6 Organic Rich Schist and Slate

a. Description

The geologic storage of CO₂ in organic rich schist and slate is a process similar to that in organic-rich shales. These rocks contain graphite, a carbon-based mineral with the capacity to adsorb gases much like other forms of organic matter in both coal and shale.

b. Location

The Walloomsac Formation is a graphitic schist that outcrops in the Berkshires in western Massachusetts (Figure 3.12). This schist is the metamorphic equivalent of organic-rich shales, and is thus the target for further investigation as possible CO₂ storage options. The Walloomsac is exposed over an area of about 225 km² (87 square miles). The outcrop pattern is disjointed because the formation is located in a structurally complex area that has undergone extensive thrust faulting.

The Walloomsac Formation was formed in the middle Ordovician about 470 million years ago. The deposits were laid down in a shallow marine basin along the margin of what was then the North American continent. The depositional environment was somewhat anoxic (low oxygen) and reducing leading to the deposition of black shales. During the Taconic Orogeny (a major mountain building event precipitated by the collision of a volcanic island arc) the shales were metamorphosed to a black carbon-bearing graphitic schist. The schist unit was then thrust up and over rocks to the west by the island arc collision. Large thrust sheets were transported westward over younger rocks producing the famous Taconic slices. Several named thrust faults were responsible for this transport. These include the Berkshire Front, Hoosac Summit, and Whitcomb Summit thrusts among others. During the transport process many units were broken up into smaller pieces and juxtaposed with units of very different ages and compositions. The Walloomsac Formation was incorporated into these thrust sheets and broken up into disparate pieces resulting in the scattered outcrop pattern observed today. Figure 3.13 shows a typical cross section through the Berkshires illustrating the complexity of the structure.

As a result of the thrust faulting it is very difficult to predict the thickness and extent of the formation in the subsurface. Nick Ratcliffe has mapped several of the 1:24,000 scale quadrangles in the Berkshires (Ratcliffe, 1974a, 1974b, 1974c, 1984a, 1984b, 1985). Estimates interpreted from his cross sections show thicknesses for the Walloomsac ranging from 61 meters to nearly 305 meters (200 feet to 1000 feet). No data are readily available regarding the total organic carbon in the formation.

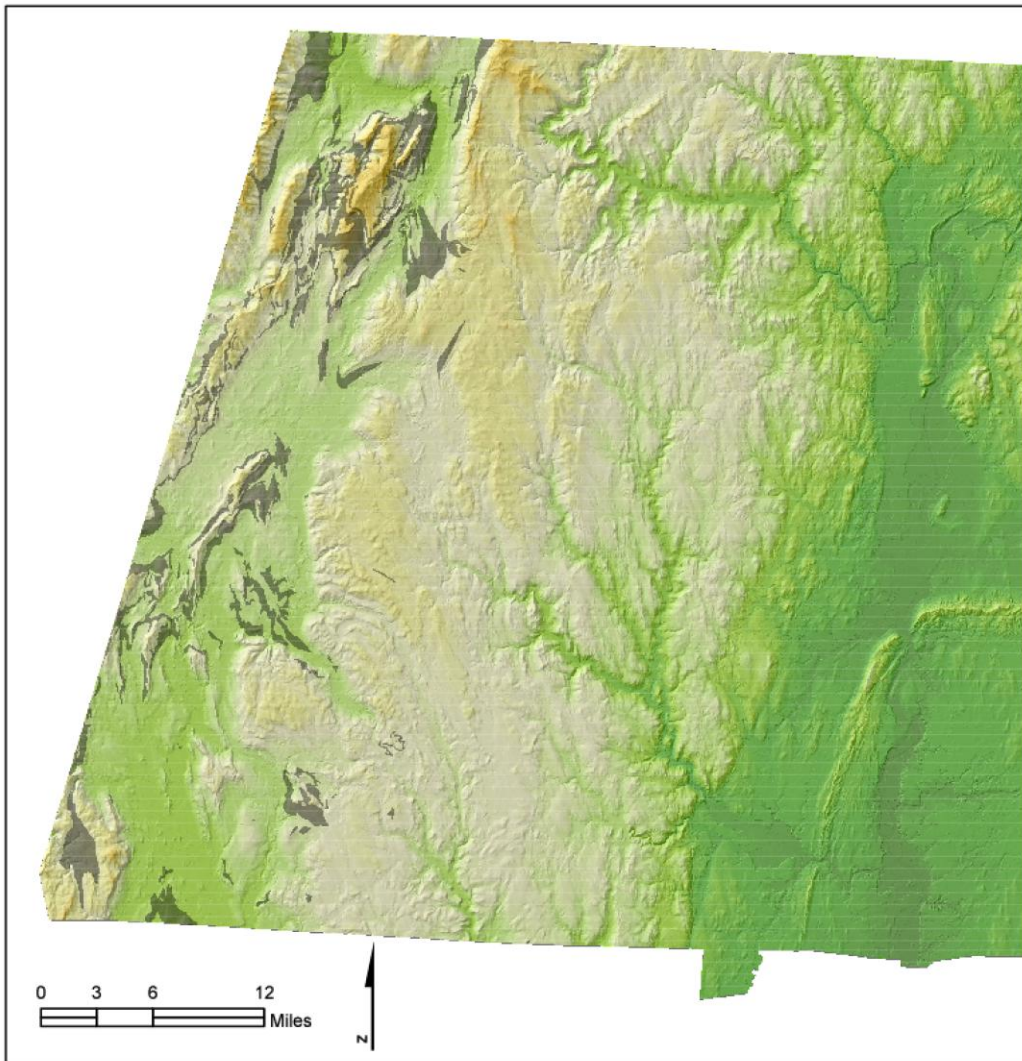
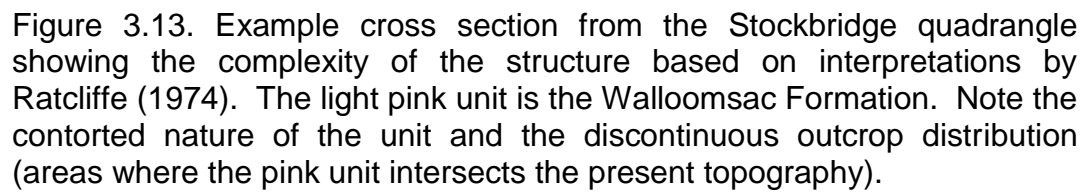


Figure 3.12. Map showing the distribution of outcrop exposures of the Walloomsac Formation in the Berkshires, western Massachusetts. Gray areas show the exposures of Walloomsac schist and comprise approximately 87 square miles.



Chapter Four

Methods and Data Needs for Determining Storage Capacity

4.1 Introduction

In 2008, the US Department of Energy – Office of Energy – National Energy Technology Laboratory released an on-line document titled *Carbon Sequestration Atlas of the United States and Canada, 2nd Edition* that describes national and regional initiatives and methods in geological carbon sequestration across the United States. Appendix B of this Atlas, prepared by the Capacity and Fairways Subgroup of the Geological Working Group of the DOE Regional Carbon Sequestration Partnerships, provides methodologies for calculating geologic carbon storage estimates in several geologic settings (hereafter Bachu et al., 2008). Using these methodologies and other resources, the following text describes the criteria and data needed to estimate the carbon storage resources for the five geologic repositories identified as possible targets in Massachusetts: saline aquifers, unmineable coal seams, organic-rich shales, basalts, and graphite-rich schists and slate.

In estimating CO₂ storage, distinction is made between the **storage resource**, or maximum mass of CO₂ that could be stored in a reservoir volume, and the **storage capacity**, which is the actual mass of CO₂ that could be realized in field application of geological carbon storage. Due to inefficiencies in CO₂ delivery and regulatory constraints on injection and well-spacing, capacity estimates are always less than the total resource estimate.

The approach employed here and in Bachu et al., (2008) relies solely on a volumetric estimate of CO₂ storage resources, in that information about area, thickness, porosity, gas adsorption capacity, or other hydrogeologic characteristics are input into the model, and a volume or mass of CO₂ is returned. As such, this approach uses information about the geologic setting that can be obtained prior to actual pilot well drilling and injection. Other methods to estimate CO₂ storage are available, but these dynamic methods rely on information that can only be obtained during active injection. For more information on dynamic methods to estimate carbon storage, refer to Burruss et al., (2009), Bachu et al., (2008) and Bachu et al., (2007).

4.2 Saline Aquifers

Bachu et al., (2008) outlines three screening criteria that saline aquifers must meet to be considered for carbon storage potential:

1. sufficient pressure and temperature to ensure supercritical CO₂
2. sufficient caprock to function as a seal to prevent vertical migration of CO₂
3. hydrogeologic conditions that isolate CO₂ within the saline aquifer

In addition, saline aquifers are regarded as those with greater than 10,000 ppm total dissolved solids [TDS]. This threshold is set to preclude use of lower salinity (potable) groundwater resources for CO₂ storage, and has been set by federal (EPA) regulations describing the Underground Injection Control (UIC) program. Thus, although there may be moderate- to high-salinity aquifers not currently

used for public groundwater withdrawal and consumption, unless these have TDS values >10,000 ppm, they will not be eligible for underground injection.

The volumetric equation to describe CO₂ storage resource for a rock unit in saline aquifers is:

$$G_{\text{CO}_2} = A h_g \phi_{\text{tot}} \rho E$$

Where G_{CO_2} is the mass of CO₂ that can be contained in the unit, A is the area of the storage basin, h_g is the thickness of the rock formation within area A , ϕ_{tot} is the average porosity of the rock formation within area A and thickness h_g , ρ is the density of supercritical CO₂ at the pressure and temperature conditions at depth in the rock unit, and E is an efficiency factor estimated to reflect the subsurface volume of pores accessible to injected CO₂.

Screening Criteria

1. *Supercritical CO₂*. Supercritical CO₂ requires a minimum temperature of 304 K (31 °C or 87°F) and minimum pressure of 7.3 mega Pascals (MPa) (73 bars or 1100 psi). Bachu et al. (2008) suggest an approximate depth to thus exceed 800 meters (roughly 2600 feet). For an average geothermal gradient of 25°C/km in the Hartford and Deerfield Basins, temperatures above 26 °C will easily be reached below 800 meters depth. Assuming a uniformly increasing hydrostatic pressure in these Basins, where mass of the overlying water in the rocks contributes pressure at depth, pressures greater than 1100 psi can similarly be achieved within 800 meters of the surface. Thus for the Hartford and Deerfield Basins, temperatures and pressures necessary to support supercritical CO₂ can be realized at depths greater than 800 meters.

2. *Caprock Seals*. The stratigraphy of the Hartford and Deerfield Basins described in Chapter Three reveals that several potential caprocks exist that may provide vertical barriers to fluid and CO₂ migration in portions of the Basins. In the Deerfield Basin, the lowermost Sugarloaf Arkose is overlain by the Fall River Beds and the Deerfield Basalt. The Fall River beds are fine-grained siltstones and shales, both of which may serve as caprocks if sufficiently impermeable. However, the Fall River Beds are not continuous throughout the Basin. Above the Fall River Beds (where present) or otherwise directly overlaying the Sugarloaf Arkose is the Deerfield Basalt. The Deerfield Basalt is fractured in surface exposures; however fracture porosity is expected to decline sharply with depth indicating that this basalt may serve as a caprock for the underlying Sugarloaf Arkose.

The eastward dip of strata in the Deerfield Basin of between 10°-15° results in surface outcrops of the Sugarloaf Arkose along the western side of the Basin. Injection of CO₂ within much of the arkose in the basin center would thus have no barrier to up-dip vertical migration. For this reason, much of the Sugarloaf Arkose is not an appropriate target for CO₂ injection. However, Walsh (2008) and Wise (1992) among others indicate faulting within the uppermost Sugarloaf Arkose, Deerfield Basalt and lowermost Turners Falls Formation. These faults appear to parallel the Eastern Border Fault, resulting in a progression of minor fault blocks in which the western side has dropped down relative to the eastern (Figure 3.5, from Walsh, 2008). The extent of displacement along these faults is unknown. They have no surface expression but they are inferred by minor E-W variations in the dip of overlying Turners Falls strata. However, displacement along these fault may create a suite of caprock seals in the Sugarloaf Arkose, as down-dropped blocks of Deerfield Basalt along the western sides of these faults will contact Sugarloaf Arkose, preventing up-dip migration of fluids within the uppermost

Sugarloaf. To confirm this, several key data need to be determined: the exact position and number of these minor faults, length of displacement, and verification that the faults serve as barriers to flow due to mineralization along the fault trace. Without these, it cannot be confirmed that fault blocks will serve as suitable caprock seals.

The Turners Falls Formation in the Deerfield Basin has no overlying caprock, and thus is not a candidate for CO₂ injection.

In the Hartford Basin, the lowermost New Haven Arkose is overlain by the Talcott Basalt, Shuttle Mountain Formation comprising shales, siltstones, sandstones and carbonates, and the Holyoke Basalt. Each of these three may serve as sufficient caprock seals to prevent vertical migration of fluids injected into the New Haven Arkose. However, as with the Sugarloaf Arkose in the Deerfield Basin, the 10° to 15° eastward dip of Hartford Basin strata results in surface outcrops of the New Haven Arkose along the western side of the Basin without any barrier to vertical migration. This renders the lower strata of the New Haven Arkose unsuitable for CO₂ injection. Similar to the Deerfield Basin, minor faulting is recognized in the northern Hartford Basin, resulting in a progression of minor fault blocks in which the western side has dropped down relative to the eastern. These faults are subsurface and inferred from changes in dip angle in the overlying Portland Formation. However, if sufficient displacement occurred, juxtaposition of eastward-dipping New Haven Arkose on the east side of the faults with basalts and shales on the west side of the faults may have resulted in a sufficient caprock seal to prevent up-dip migration of CO₂ in the arkose. In central Connecticut, abundant shallow block faulting within the uppermost New Haven Arkose, the basalts, and the overlying Portland Formation was detected in the Park River cores collected in Hartford, CT by the USACE (Zerezghi, 2007; Olsen et al., 2005); here, a single fault zone was expressed by up to six separate faults each with at least meter-scale displacement, all within a horizontal transect of approximately two miles. Under this circumstance, it is difficult to envision these multiple faults providing an effective seal. If this style of multiple minor faults within a fault zone extends northwards into Massachusetts, then the entire Hartford Basin is an unlikely target for CO₂ injection.

This situation is complicated because the sense of dip in strata shifts from east to southeast to south in the northern portion of the Hartford Basin in Massachusetts. The outcrop of basalts outline this turn, as the N-S trending ridge of Mount Tom is continued by the E-W trending ridge of the Holyoke Range. In the absence of faulting near the Holyoke Range, there may be no caprock seal to prevent up-dip northward migration of fluids in the New Haven Arkose. A fuller picture of the subsurface architecture of faulting and fault displacement is needed to determine if the uppermost New Haven Arkose is suitable for CO₂ injection.

The Portland Formation in the Hartford Basin has no overlying caprock to prevent vertical migration of fluids, and thus is not a candidate for CO₂ injection.

3. *Hydrogeologic conditions that isolate CO₂ within the saline aquifer.* Beyond limits on vertical migration dictated by the presence of caprocks, characteristics such as rock porosity and permeability, the areal extent of a formation, and groundwater salinity contrasts within, above and below a rock unit targeted for injection may impact the long-term isolation of fluids within an aquifer. Many of these criteria are incorporated below under ***Volumetric Model Data***.

Salinity is a particular threshold criterion for consideration of a rock unit for geologic carbon storage, because EPA UIC regulations require injection wells be sited in aquifers with >10,000 ppm

TDS. Salinity information for depths in the New Haven Arkose and Sugarloaf Arkose is not directly available, and must be inferred from analogous basins, extrapolation of shallow well salinities (Figure 3.7), and related geochemical analyses of arkose cement and overgrowth compositions. The *Groundwater Atlas of the United States* published by the USGS describes salinities in shallow groundwater wells (<152 meters depth) in both the Hartford and Newark (Rockland County, NY) basins as low (average 202 and 170 ppm, respectively), with maximum values of only 2000 ppm (Olcott, 1995). This same study suggests average salinities in shallow groundwaters in the Newark, Gettysburg and Culpepper Basins extending from New Jersey south into Virginia (Trapp and Horn, 1997). A comprehensive study of trace metal chemistry in groundwater wells from the Newark Basin in SE Pennsylvania similarly reveal low salinities in the 100s ppm (Senior and Sloto, 2006); however these were also shallow wells extending no more than several hundred feet depth.

In contrast to these data for shallow wells, geochemical and geologic evidence suggest that saline brines once existed at depth in the Hartford and Deerfield Basins, as well as other Mesozoic rift basins in eastern North America. This evidence includes the extensive diagenetic cements and overgrowths that formed in the arkose, especially albite, that required elevated Na^+ concentrations. Fluid inclusions in quartz filling fractures in the New Haven Arkose contain NaCl concentrations between 14-23%, indicating very high salinities (well over 100,000 ppm TDS) at the time of quartz mineralization (Ryan, 1986; Manning et al., 2009). Merino et al (1997) similarly suggests elevated salt content in subsurface brines early in the history of these basins. It is unknown if subsequent freshwater recharge (enhanced by erosion of 2-3 km of now-removed Mesozoic sediment) over the past 200 million years may have led to dilution of these brines in the deepest portion of the basin. It is common for shallow flow systems in sedimentary basins to be confined to the upper approximately 300-500 meters, and saline formation waters are commonly found (where explored) at greater depths in aquifers throughout the Appalachian Mountains and Midwest USA (Lloyd and Lyke, 1995). No studies could be found that document salinities at depth in the Mesozoic rift basins of eastern North America. This is attributed to lack of deep wells drilled associated with oil and gas exploration in the region. The potentially hydrocarbon-bearing rocks in the Hartford and Deerfield Basins are nearly uniformly mature to over-mature in thermal maturity, and have not been targets for oil and gas exploration.

It remains unknown if salinities in the New Haven and Sugarloaf Arkose units would be sufficiently high (>10,000 ppm TDS) to allow for inclusion as targeted CO_2 injection units. At present, this may be the single greatest barrier to evaluating if these rock units can be candidates for CO_2 injection. It is recommended that one or more test wells be drilled into the uppermost Sugarloaf Arkose and New Haven Arkose, to depths of at least 1000 meters (3000 feet), to establish if elevated salinities are present.

Volumetric Model Data

1. Area. The Deerfield Basin extends roughly 5 km (3 miles) E-W and 25 km (15 miles) N-S, resulting in a total area of 125 km² (45 sq. miles). However, as described above under caprock criteria, much of the Deerfield Basin is not a suitable target for CO_2 injection. Instead, the appropriate area to consider is the area of the blocks offset by minor faulting, as shown in Figure 3.5 (from Walsh, 2008). If these fault blocks extend fully N-S through the Basin, and if the fault dip angle is accurate (30° from vertical), then there may result up to four subsections of the uppermost Sugarloaf Arkose appropriate for CO_2 injection. Conservatively, these may extend 20 km (12.5 miles) N-S and 5 km (3 miles) E-W, leading to an area appropriate for CO_2 injection of 100 km² (37 sq. miles). It should be noted that this area estimate depends entirely on the presence of minor faulting in the Deerfield Basin of sufficient

displacement to juxtapose Deerfield Basalt against Sugarloaf Arkose, with sufficient mineralization along the fault trace to seal the fault against fluid migration.

The portion of the Hartford Basin in Massachusetts extends 25 km E-W (15 miles) and 30 km N-S (19 miles), resulting in a total area of 750 km² (285 sq. miles). However, as described above under caprock criteria and analogous with the Deerfield Basin, much of the Hartford Basin is not a suitable target for CO₂ injection. Instead, the appropriate area to consider is the area of blocks offset by minor faulting, as depicted on the CT state geologic map and in Hubert et al. (1992). Three fault blocks are depicted on the CT geologic map, and extensive minor faulting is shown on the Mass. state geologic map within basalts of the Mount Tom Range. Conservatively, these fault blocks may extend up to 25 km (15 miles) N-S from the Connecticut Border towards the Mount Holyoke Range, and total up to 20 km (12.5 miles) E-S, leading to an area in the New Haven Arkose potentially appropriate for CO₂ injection of 500 km² (187 sq. miles). It should be noted that this area estimate depends entirely on the presence of minor faulting in the Hartford Basin of sufficient displacement to juxtapose overlying basalts, shales and carbonates against the New Haven Arkose, with sufficient mineralization along the fault trace to seal the fault against fluid migration, and with similar faulting continuing along the south side of the Holyoke Range.

2. Thickness. The Sugarloaf Arkose in the Deerfield Basin averages 2 km (1.25 miles) of stratigraphic thickness. However, this thickness is highly variable, as depth-to-basement depends strongly on the texture and architecture of fault structures in the underlying Paleozoic basement rocks (Figure 3.3, from Walsh, 2008). The thickness of potential fault-bounded blocks in the uppermost Sugarloaf Arkose is at this point unknown, although measured displacement along minor faults in stratigraphically higher formations in the Basin are no more than 100 meters. Using this estimate, the appropriate thickness to consider for the uppermost portion of Sugarloaf Arkose that may be suitable for CO₂ injection is 100 m (300 feet).

The New Haven Arkose in the Hartford Basin averages 3 km (2 miles) of stratigraphic thickness. Displacements along potential faults in the New Haven Arkose are likely greater than displacement along faults in the Deerfield Basin, because changes in dip in the overlying Portland Formation are greater and because measured displacements further south in Connecticut (such as in the Park River cores and at multiple surface fault traces at Meriden Mountain) are up to one kilometer (over 3000 feet). Using this estimate, the appropriate thickness to consider for the uppermost portion of New Haven Arkose that may be suitable for CO₂ injection is conservatively 500 meters (nearly 1600 feet).

3. Porosity. There are two types of porosity to consider in estimating average rock unit-wide porosities to use in volumetric models: matrix porosity and fracture porosity. Matrix porosity is the residual interconnected volume of open space between mineral grains that remains following deposition, burial, compaction and diagenetic cementation. Fracture porosity is pore volume that has been generated in the rock long after burial due to tectonic stresses leading to fracturing and faulting.

The Sugarloaf and New Haven Arkoses exhibit abundant early diagenetic cements and overgrowths composed of quartz, hematite, carbonate and albite, which served to reduce initial burial porosity (Walsh, 2008; Hubert et al. 1992), although hydrocarbon migration during thermal maturation of organic-rich shales in the East Berlin Formation and Fall River Beds indicates that early in the basins' histories, permeability was sufficient to prevent generated hydrocarbons from being retained in the rocks. Petrographic analyses show that on average 15-20% of the original 40% porosity remains in

the Sugarloaf Arkose, with some samples showing as little as 5% porosity (Walsh, 2008). In contrast, illitized portions of the Sugarloaf Arkose were measured to contain only 1-3 % residual porosity (Taylor, 1991). Olcott (1995) reports an average value of 7% porosity for sandstones of the Hartford Basin, although further reference for this estimate is lacking. Porosity in sandstones of the Portland Formation (uppermost Hartford Basin) has been measured at 10% (LeTourneau and Huber, 2006); gas and liquid permeabilities in these samples were low (5 and 7 milliDarcys, mD). In contrast, permeabilities in the eolian sections of the New Haven Arkose and similar eolian strata in the Pomperaug Basin were much higher (up to 395 mD for gas, 368 mD for liquids) (LeTourneau and Huber, 2006), with associated higher matrix porosities between 14-21%. The Pomperaug Basin is a small Mesozoic rift basin analogous to the Hartford and Deerfield Basin located in western Connecticut.

It can be expected that matrix porosity in the Sugarloaf and New Haven Arkose are unlikely to decrease significantly with depth into the basins. In contrast, fracture porosity which is abundant in surface exposures of these arkoses is likely to decline greatly, as fractures are sealed or pinched out under greater pressures in the subsurface. With these considerations, the average formation porosity for the Sugarloaf Arkose (where not illitized) to employ in CO₂ storage models is 15-20%, with a similar range for the New Haven Arkose (14-21%).

Summary of Massachusetts Saline Aquifer Resources with Comparison

Evaluation of potential on-shore saline aquifer resources in Massachusetts indicates that portions of two sedimentary basins (Deerfield and Hartford Basins) in western Massachusetts may be candidates for CO₂ injection. The area of the Deerfield Basin potentially suitable for injection totals 100 km² with relevant formation thickness of approximately 100 meters; however, more accurate assessment of this area and thickness relies on high-resolution depictions of subsurface architecture in the Basin – specifically the presence, number and displacement along minor faults that would provide caprock seals for injection into the Sugarloaf Arkose. The area of the Hartford Basin in Massachusetts potentially suitable for injection totals 500 km² with relevant formation thickness of approximately 500 meters; however, more accurate assessment of this area and thickness relies on high-resolution depictions of subsurface architecture in the Basin – specifically the presence, number, orientation and displacement along minor faults that would provide caprock seals for injection into the New Haven Arkose. At present it cannot be determined if the number of and displacement along faults and fractures of the subsurface in these basins is sufficiently simple to allow for suitable caprock seals, or if the basin structure and architecture are too complex and too fractured to afford suitable caprock. Another critical unknown at this time is whether saline waters are present at depth in either of these basins. EPA UIC regulations require TDS > 10,000 ppm for any geologic formation targeted for injection. Shallow groundwater wells in the Hartford and Deerfield basins (or other analog Mesozoic rift basins) do not achieve this high salinity. However, extrapolation of shallow well salinities to greater depth does suggest higher salinities may be achieved below approximately 250 to 300 meters and certainly below 1 km depth. Moreover, ample geochemical evidence suggests that highly saline brines were at one time present at depth in these basins.

Comparison with other saline aquifer systems reveals that saline aquifer storage resources in Massachusetts will be relatively small. The *Atlas of Carbon Sequestration II* (2008) estimates storage in saline aquifers for each state. Many states show storage potential between 10,000-100,000 million metric tons CO₂, while Massachusetts has an estimated 6-25 million metric tons CO₂ potential in saline

aquifers. It should be noted that this estimate for Massachusetts derives from extrapolating a portion of a saline aquifer in New York state across the border into far western Massachusetts; saline aquifers in the Hartford or Deerfield Basins were not included. This extrapolation of a saline aquifer from New York into western Massachusetts is also inaccurate, as the saline aquifer in Paleozoic sandstones does not extend east of approximately the Hudson River.

As described previously, there are several Mesozoic rift basins along the eastern margin of North America that are analogous to the Hartford and Deerfield Basins in gross sedimentology, origin, structure, and tectonic signatures. These have been reviewed by Schlische (1993) and Schlische and Olsen (1990). These basins range in size from the small Pomperaug Basin in CT (44 km²) to the largest Fundy Basin in Nova Scotia (27,000 km²). The total combined Hartford and Deerfield Basins comprise 4800 km², smaller than the Newark Basin (9500 km²), but comparable with the Gettysburg (PA – 4000 km²), Culpepper (VA – 3700 km²), and Deep River (NC – 5800 km²). To date, none of these basins has been proposed as a site for CO₂ injection and geologic carbon storage. Other basins that are proposed and being tested for CO₂ injection are larger and have a greater history of geologic exploration (related to oil and gas production), such that more information about the basins' structure, stratigraphy, and deep groundwater salinities is known. Among these is the Illinois Basin in IL, IN, KY. This basin extends approximately 155,000 km², or 30 times the size of the combined Hartford and Deerfield Basins. The deep Paleozoic sandstones, shales and carbonates in this basins are known to contain high salinity brines well above 10,000 ppm TDS. The structure of this basin is uncomplicated, although some modest faulting and displacement is detected. The stratigraphy includes ample, repeated caprocks of shale and carbonate. Lastly, the basin contains ample coal, oil and gas resources, leading to (1) an existing network of wells and pipelines that may be incorporated into an injection scheme, and (2) potential to target more than one type of geological storage formation, in that saline aquifers, coals, shales, and oil/gas reservoirs are all present here. Other basins being tested for potential CO₂ injection into saline aquifers include the Williston Basin in North Dakota – Montana (360,000 km²), estimated to have a maximum CO₂ storage capacity of over 40 billion metric tons, and saline aquifers along the entire Gulf of Mexico coast and inland 300-500 km to southern Arkansas, Mississippi, Alabama, Louisiana and central Texas, with a total CO₂ storage resource estimated between 2000-9000 billion metric tons.

4.3 Unmineable coal seams

NETL outlines two screening criteria that unmineable coal seams must meet to be considered for carbon storage potential:

1. a minimum depth necessary to meet >10,000 ppm TDS, to ensure that water quality standards are met for CO₂ injection. No maximum depth is described, and will be limited by technologies and economic considerations for deep drilling and injection. Adequate CO₂ injection requires a minimum permeability of 1-5 mD. In deep coal seams, coal cleat closure with increasing pressure has limited production of coal bed gases such as methane, with permeability below the 1 mD threshold occurring at depths below approximately 1000 meters (Bustin, 1997; Zuber et al., 1996). Coal bed gas recovery has been limited to unmined coals above this depth, and without artificially enhanced permeability (induced by hydraulic fracturing), CO₂ injection is likely limited to coal seam depths above 1000-1500 meters (Bachu, 2007; Bachu et al., 2007).
2. unmineability of the coal, based on current and future projected mining technologies. Depth, thickness of seams, ash content, number of seams, and coal rank influence

mineability, with thinner seams, deeper seams, higher ash content and lower rank negatively impacting mineability.

In addition, Bachu et al., (2007) outlines additional criteria that must be considered for CO₂ injection and storage in coal seams:

1. adequate permeability (1-5 mD minimum) to facilitate injection
2. simple geologic structure with minimal faulting and folds
3. homogeneous and confined, with an overlying seal or caprock extending over the entire rock unit under consideration
4. low water saturation, as coals need to be dewatered prior to gas recovery and CO₂ injection
5. high gas saturation, although this is only relevant for enhanced coal bed methane recovery [CBM]
6. concentrated coal deposits, with fewer and thicker coal seams, although this has been challenged by some, arguing that future mining technologies may target thicker seams and that thinner seams are least likely to be future mining targets.

The volumetric equation to describe CO₂ storage resource in unmineable coal seams is:

$$G_{\text{co}_2} = A h_g C \rho_s E$$

Where G_{CO_2} is the mass of CO₂ that can be contained in the unit, A is the area of the storage basin, h_g is the composite thickness of coal seams within area A , C is the standard volume of CO₂ that can be stored in a volume of coal, based on Langmuir adsorption isotherms measured on the targeted coals, ρ is the standard density of CO₂ (1.873 kg/m³, used to convert CO₂ from volume units to mass units), and E is an efficiency factor estimated to reflect the subsurface volume of pores accessible to injected CO₂.

Screening Criteria

1. Depth of coal

As described above, the stratigraphy and structure of the Narragansett Basin remain poorly understood. Of the four described stratigraphic units within the basin, only the Rhode Island formation is known to contain coal. This formation comprises pebbly conglomerate with siltstone, mudstone, shale and coal (Lyons and Darrah, 1978). The coal is widespread, but discontinuous and of variable thickness (Skehan et al., 1981). The overall structure of the basin is a suite of NE-SW trending folds and faults, with the NW and SE sides of the basin bounded by normal faults. There are 3 major synclines and two major anticlines recognized in the basin, with the uppermost Dighton Conglomerate exposed in the center of the synclines. Projecting dip angles of 45° between syncline/anticline axes spaced 10 km apart, it can be estimated that there may be up to 5 km of lower Rhode Island Formation (and underlying strata) underneath the axis of the anticlines. The axes of synclines, where coal is deepest and overlain by the thickest sequence of shale caprocks, may be suitable candidates for CO₂ injection, if salinities and other criteria are met. Coal measures are only exposed at the surface along the flanks of synclines along the western margins of the basin, extending south into Rhode Island; these shallow exposures would not be targeted for CO₂ injection.

Salinity in coal seams of the Narragansett Basin is unknown. Shallow groundwater wells in the Rhode Island Formation in SE Massachusetts do not reveal elevated salinities, but no measurements of

salinities of waters at depth in the basin are available, because no wells have been drilled targeting these locations. Comparison with other analogous coal-bearing basins reveals a complex picture of below-ground salinities. Shallow groundwater wells in the anthracite-bearing strata in NE Pennsylvania reveal elevated salinities of up to 3000 ppm TDS (Hallowell and Koester, 1975), and coal mining activities in western Pennsylvania have resulted in elevated sulfate concentrations in surface waters up to 3000 ppm (Sams and Beer, 1999), although this is attributed to near-surface acid mine drainage and not to inherently high salinities in formation waters at depth. Elsewhere, lower-rank Cretaceous coals of the Alberta Basin reveal low salinity waters in shallow sections of the basin where meteoric recharge has reduced salinity, but high salinities (up to 130,000 ppm) in the deepest portions of the basin at 3600 m depth in the Manville coal seams (Bachu, 2007). At this point without direct drilling and measurement of water samples from deep coals in the Narragansett Basin, it is not possible to predict if salinities will fall above the 10,000 ppm TDS threshold required for CO₂ injection.

2. Unmineability

Mining of coal in the Narragansett began in the late 1800's at Mansfield, MA, Cranston, RI, and Portsmouth, RI. Mining ceased within a few decades as economically mined coal was exhausted; cheaper coal with lower ash content became available from other states, although some mining continued at Cranston until 1959. These mines were located along the western side of the basin along the upturned flanks of synclines. No mining or exploration has been conducted for deep coals buried within the center of the two major anticlines of the basin.

It is highly likely that coals in the Narragansett Basin will continue to be classified as unmineable. The coals are of extremely high rank, grading from anthracite to meta-anthracite in the north to nearly graphite in the south. This extreme rank negatively impacts BTU values of the coal (i.e. energy released on combustion). Early reports suggested that the coals measure 11-17% ash content where sampled at quarries and mines (Shaler, Woodworth and Foerste, 1899), although higher ash contents (33-50%) have been reported in more recent studies (Lyons and Chase, 1981). Water content of the coal is reported to be between 5-10%, although no recent measurements have been conducted.

Volumetric Model Data

1. Area. The portion of the Narragansett Basin in Massachusetts extends NE from the Rhode Island border for approximately 45 km, with a NW-SE width of 25 km at the border narrowing to 10 km in the northeast. This yields a total area of the basin of roughly 800 km². Within this, candidates for CO₂ injection would be confined along the axes of the two major anticlines in the basin. Conservatively, these extend 40 km with a width of approximately 8 km each, totaling an area of approximately 640 km². More detailed mapping of the Basin, including surficial surveys of fold trend and plunge, northward extent, and deep basin architecture through seismic surveys would be required to refine this estimate. At a maximum, the reconstructed unfolded area of each anticline would extend approximately 14 km in width; due to the steep downward dip of strata along the axes of the folds, the area of formation is 70% greater than depicted in map view. This leads to a possible areal extent of anticline targets of more than 1000 km².

2. Thickness. Coals in the Rhode Island formation at outcrop are widespread but also thin and discontinuous. Individual seams range up to 10 meters thick. At the MassLite Quarry in Mansfield, MA, 14 individual coal seams were measured ranging from 1-10 meters in thickness (Skehan et al.,

1981). These were overlain by shale and siltstone, suggesting the potential of good caprock seals for these coals. However, the scale of exploration ranged only several hundred meters; this provides a very small picture of the stratigraphy and structure of these coals and their adjacent strata, making extrapolation to deeply-buried coals elsewhere in the basin very uncertain. The composite thickness of the coal at Mansfield is approximately 100 meters. Given the discontinuous nature of these coals, extrapolation of this thickness to the interior of anticlines in the Narragansett Basin is uncertain.

3. Adsorption capacity. As an organic substrate, coal exhibits the capacity to adsorb low-molecular weight gases onto its surface. In the subsurface, methane gas is often trapped on the surface of coal. Extraction of this methane gas from the coal leads to the natural gas resource known as coal bed methane [CBM]. Enhanced recovery of CBM has been proposed via injection of CO₂ into subsurface coal seams, allowing CO₂ to replace adsorbed methane molecules and increase production of natural gas. Adsorption capacity of CO₂, methane and other gases is temperature dependent, and follows a Langmuir pressure-dependent isotherm relationship in which gas adsorption capacity (expressed in standard cubic feet of gas per ton of coal: scf/ton) increases with increasing applied pressure asymptotically up to a maximum capacity termed the Langmuir volume. In practice, this means that pressurized gas (CO₂ or methane) is applied to a coal and adsorbed up to a threshold capacity, above which no further adsorption is achieved with further increases in pressure. More CO₂ than methane can be absorbed per unit volume of coal, leading to the proposed geologic storage in coals via CO₂ injection; between 3 and 13 molecules of CO₂ are required to replace one molecule of methane, depending on temperature, coal water content, and coal rank.

In general, Langmuir volumes in coals range in the 100's to near 1000 scf/ton. High rank coals (anthracites) exhibit higher gas adsorption capacities than equivalent lower rank coals (Laxminarayan and Chosdale, 1999; Krooss et al., 2002), with Langmuir volumes in anthracites from NE Pennsylvania exhibiting adsorption capacities of 1000 scf/ton for methane and 1500 scf/ton for CO₂ (Figure 4.1, from Buruss, 2003). In lower rank coals, the difference in adsorption capacity between methane and CO₂ is greater, indicating that more CO₂ needs to be applied to release methane, while overall Langmuir volumes are lower. Ash content and water content negatively influence gas adsorption capacity by reducing total exposed surface area that is coal and not mineral matter (Laxminarayan and Chosdale, 1999; Bachu, 2007; White et al., 2005).

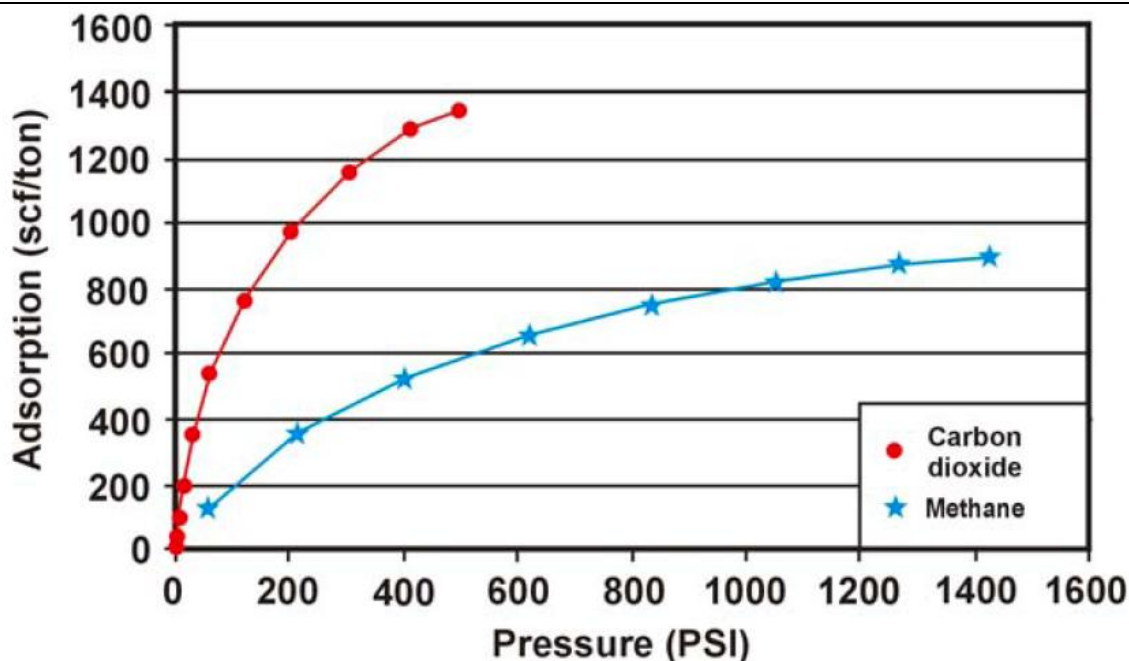
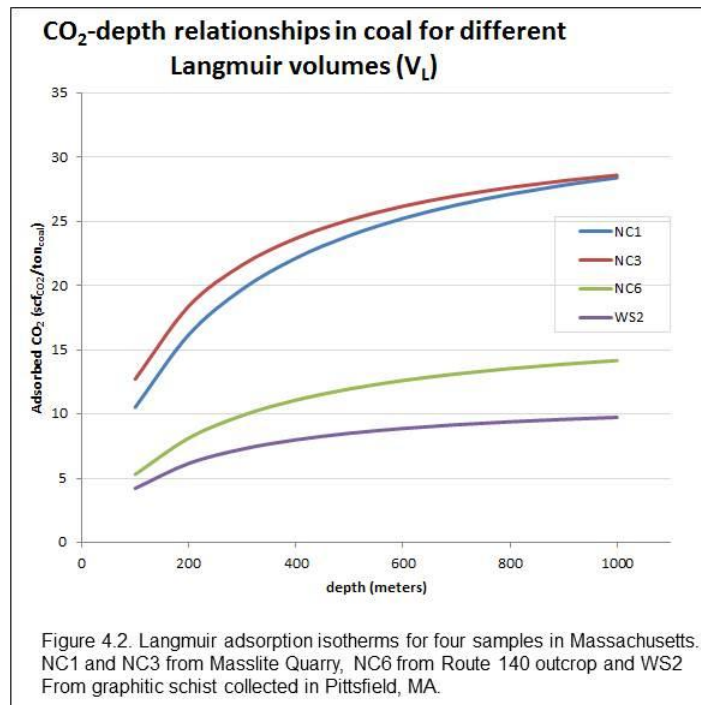


Figure 4.1. Extrapolated Langmuir volumes for anthracite in NE Pennsylvania (7-foot Seam, Lackawanna County, PA) show theoretical methane adsorption capacity of 1000 scf/ton, while CO₂ adsorption capacity is higher at approximately 1500 scf/ton. The high Langmuir volume for this and other anthracites suggest similarly high CO₂ adsorption capacity may be realized in anthracite coals of the Narragansett Basin. From Burruss (2003) <http://www.coal-seq.com/Proceedings2003/Burruss.pdf>.

Prior to this project, no data were available for the adsorption capacity of coals in the Narragansett Basin. Accordingly, during the summer of 2011, six samples of coal were collected from two locations. Four samples were collected from the Masslite Quarry operated by the Lorusso Corporation in Plainville, MA. Samples were collected from outcroppings of folded beds along the various benches in the quarry. Samples are described as dark gray, shaly coals. No pure anthracite was found at the quarry. Two additional samples were collected along the southbound entrance ramp at the intersection of Route 140 and Interstate-95 in Foxboro, MA. These samples are coaly, black shales exposed at the base of the outcrop along the entrance ramp. Ultimately, three sample (two from the Masslite Quarry and one from the entrance ramp exposure) were selected and sent to TerraTek in Salt Lake City, Utah for Langmuir adsorption analysis along with a sample of graphitic schist from the Walloomsac Formation in Pittsfield, MA (see section 4.6 below) . Results are provided in Appendix 1.

Results indicate that the three coal samples exhibit CO₂ adsorptions capacities of 35, 33 and 17 scf/ton for NC1, NC3 and NC6, respectively (Appendix 1, Figure 4.2). These adsorptions capacities are much lower than those observed in analogous anthracite coal deposits where adsorption capacities of 1000 scf/ton are observed. These low adsorption capacities are most likely due to the high ash content of these deposits (~95%) indicating the samples are not pure coals and have other mineral matter contained in them. Accordingly, these data represent a minimum adsorption capacity for Massachusetts coals.



Summary of Massachusetts Unmineable Coal Seam CO₂ resources

Evaluation of potential unmineable coal seam CO₂ storage resources in Massachusetts reveals that portions of the Narragansett Basin may be suitable for CO₂ injection. The areas would be confined to two structural anticlines in the Basins, with injection targeted to coal seams within the Rhode Island Formation. As basin structure and architecture have not been adequately mapped or imaged for the subsurface, the areal extent of coal seams can only be estimated by extrapolating measured surface stratigraphy and dip into the subsurface, leading to an estimated area of approximately 640 km². The total composite thickness of Narragansett Basin coal seams is difficult to evaluate in the absence of core material from the target locations within these anticlines, but nearby exposures of coal at the MassLite Quarry in Mansfield, MA indicate a composite thickness of 100 meters, spread over 14 seams ranging between 1-10 meters thick. Coals in outcrop are discontinuous, lenticular, and bound by overlying strata comprising shales, siltstone, sandstone and conglomerate; where overlain by shales, these coals would have adequate caprock seal to prevent migration of injected CO₂. Langmuir volumes and thus adsorption capacity for these coals are not well defined but analysis of three samples from the Narragansett Basin and comparison with analogous high-rank anthracites with similar ash and water content suggest a CO₂ adsorption capacity ranging from 17 scf/ton to 1000-1500 scf/ton. Actual adsorption capacity measurements on Narragansett coals are low due to the high ash content of the samples. It is unknown if subsurface formation water salinities reach or exceed the threshold UIC regulation of >10,000 ppm TDS.

4.4 Organic Rich Shales

Storage of CO₂ in organic-rich shales has been proposed as a potential technology for geologic carbon sequestration. At present, however, no methodology for estimating CO₂ storage resource in

shales has been developed. By analogy with unmineable coal seams, storage in organic-rich shales relies on adsorption of CO₂ onto surfaces of organic matter within the rock. Additional storage may be achieved analogous with saline aquifers, in that supercritical CO₂ may be stored within shale pore spaces. However, given the low average porosity and permeability within shales, pore-space storage is not expected to yield significant storage potential.

At this time, no screening criteria or volumetric model data have been established for storage of CO₂ in shales. By analogy with storage in coals, it can be expected that threshold criteria will include >10,000 ppm TDS per UIC regulations. Additionally, storage resource calculations are likely to rely on the area, thickness, and adsorption capacity of targeted shales.

A limited extent of organic-rich shale occurs in the Hartford and Deerfield Basins. In the Hartford Basin, shales ranging up to 4% total organic carbon are found as thin units within East Berlin, Shuttle Mountain and Portland Formations. Similarly high total organic carbon contents are observed in the Fall River Beds and Turners Falls Formation. The areal extent of these in the subsurface is similar to that estimated for CO₂ injection candidates of the Sugarloaf and New Haven Arkose, approximately 500 km². The presence and displacement of faults in these basins will dictate how much of this area has sufficient caprock seal for CO₂ injection. The total composite thickness of organic-rich units within the shales is limited to less than 50 meters. No data exist for adsorption capacity of CO₂ in organic-rich shales of the Hartford and Deerfield Basins or other Mesozoic rift basins. Given the high thermal maturity throughout much of these basins, adsorption capacity is expected to be modest compared with coals. Adsorption capacities in typical organic-rich gas shales in the Appalachian Basin range between 50-200 scf/ton for CO₂ (Atlas of Carbon Sequestration II, 2008). As with the saline aquifer storage, it is unknown if shales in the Hartford and Deerfield basins exhibit elevated salinities at depth sufficient to meet or exceed UIC regulation thresholds (>10,000 ppm TDS).

4.5 Deep Basalt

Deep basalt formations are currently being proposed as geological storage units for CO₂. While research is being conducted on storage capacity, retention time, reservoir stability, and the risk for leakage, at present no capacity calculation methodology has been recognized by the National Energy Technology Laboratory Carbon Sequestration Program (*Carbon Sequestration Atlas of the United States and Canada*, 2008). The storage of CO₂ in basalt formations relies on geochemical trapping, that is, reactions between CO₂ and minerals in the basalt to create new stable carbonate minerals that permanently remove CO₂ (Goldberg et al., 2008; Kelemen and Matter, 2008; Oelkers et al., 2008). This complex process occurs naturally in high-temperature regions with basalt and circulating, CO₂-rich fluids such as at mid ocean ridges and basaltic hydrothermal systems. In brief, minerals common to basalts such as olivine, amphibole, and calcium-rich plagioclase react with supercritical CO₂ at temperatures above 60° C (Goldberg et al., 2008; Plasynski et al., 2008) to form calcium- and magnesium-carbonate minerals. Experimental simulations of basalt-CO₂ reactions reveal carbonate mineral formation at 100 °C and 1500 psi CO₂ on a timescale of years (Plasynski et al., 2008).

Given that no established methodology exists for CO₂ storage resource estimates in basalt, little can be said about potential candidates for basalt storage in Massachusetts. Nonetheless, factors such as thickness and areal extent can be reported. There is one basalt unit within the stratigraphy of the Deerfield Basin, called the Deerfield Basalt. This basalt ranges from 0-133 meters thick, and dips eastward from outcrop exposures in the center and west of the basin at 10-15° (Walsh, 2008). In the

Hartford Basin are three basalt units, the Talcott, Holyoke and Hampden basalts. Geochemical evidence suggests that the Deerfield and Holyoke are formerly-connected lava flows now separated by erosion (Philpotts, 1998). The thicknesses of the Talcott, Holyoke and Hampden basalts are similar to the Deerfield basalt. Together, these basalts have an area of approximately 500 km².

Experimental evidence suggests that these reactions require elevated temperatures not likely to be realized in basalts near the surface in the Hartford and Deerfield Basins. Assuming an average geothermal gradient of 25°C/km for these basins, elevated temperatures required for CO₂-basalt reactions might be achieved at 3 km depth. This reduces the areal extent of basalts above a minimum 75°C threshold to less than 100 km².

4.6 Organic-Rich Schist and Slate

Organic-rich schist and slate have not been recognized as potential targets for geological CO₂ storage. However, graphite in these geologic formations may function similar to organic matter in coals and shales, in which CO₂ can be adsorbed onto graphite surfaces. There is an abundance of graphite-rich slate and schist in formations of western Massachusetts such as the Walloomsac Schist. One sample was collected from an outcrop of Walloomsac schist in Pittsfield, MA during the summer of 2011. This sample (WS2) was analyzed at TerraTek to determine its adsorption capacity. The results indicate a low adsorption capacity of approximately 11scf/ton (see figure 4.2). In addition, the complex structure of faulting and folding in western Massachusetts in the Berkshire has lead to this unit being highly disconnected and of limited areal extent. Until methods are established and verified that graphitic schists and slate provide viable CO₂ storage potential, these geologic formations should be regarded as tentatively possible candidates at best.

Chapter Five

Estimates of CO₂ storage resources in Massachusetts

5.1 Introduction

The methodologies for CO₂ storage resource potential outlined in Chapter 4 of this report follow procedures established by Bachu et al. (2008). Estimates of CO₂ storage resource potential have been calculated for two geologic formations in Massachusetts: deep saline aquifers in sandstones the Connecticut River Valley and unmineable coal seams in southeastern Massachusetts. Other formations with potential CO₂ storage capacity (i.e. basalts and shales in the Connecticut River Valley, and graphitic schists in the Berkshires) lack established methodologies for calculating storage resource, and thus no storage resource has been calculated for these formations; however, as methodologies develop, these formations should be considered as contributors to the total CO₂ storage resource available within Massachusetts. However, experiments on the CO₂ storage potential are being performed independently and will be presented in a separate report.

The approach for calculating CO₂ storage in geologic formations recommended by Bachu et al. (2008) is based on volumetric estimates of total CO₂ that could be contained in a given formation. The specific volumetric model and data needs for each formation are described in Chapter 4. Chapter 4 also describes available data and estimates drawn from published literature on the geologic formations in Massachusetts and on analogous formations in other geographic settings.

5.2 Estimate of CO₂ storage resource in saline aquifers

The volumetric equation to describe CO₂ storage resource for a rock unit in saline aquifers is:

$$G_{\text{co}_2} = A h_g \phi_{\text{tot}} \rho E$$

Where G_{CO_2} is the mass of CO₂ that can be contained in the unit, A is the area of the storage basin, h_g is the thickness of the rock formation within area A , Φ_{tot} is the average porosity of the rock formation within area A and thickness h_g , ρ is the density of supercritical CO₂ at the pressure and temperature conditions at depth in the rock unit, and E is an efficiency factor estimated to reflect the subsurface volume of pores accessible to injected CO₂.

a. Deerfield Basin, Sugarloaf Arkose

As described in Chapter 4, within the stratigraphy of the Deerfield Basin, the Sugarloaf Arkose is the most viable candidate for CO₂ storage. The input data for calculation of total CO₂ storage in this formation are:

area	A	100 km ²
formation thickness	h_g	100 m
density of supercritical CO ₂	ρ	500 kg m ⁻³
porosity	Φ_{tot}	5-20%
efficiency	E	2%

where 2% efficiency is the mean efficiency calculated by Bachu et al. (2008) for injection into saline aquifers based on a suite of Monte Carlo simulations of injection efficiency. The density of supercritical CO₂ varies with temperature and pressure; for this calculation, 500 kg m⁻³ is an approximate average density for the temperatures and pressures likely to be achieved in the Deerfield Basin. Together, these data yield a maximum (theoretical) CO₂ storage resource in the Deerfield Basin of **5 to 20 million tons CO₂** depending on rock porosity. This maximum resource potential is highly unlikely to be realized as true storage capacity, due to uncertainty in rock porosity and limitations in the actual land area that may be available for CO₂ injection. Porosity is uncertain for the Sugarloaf Arkose at depths that would be targeted for injection; porosities in surface samples of this formation range between 15-20%, while porosity can be expected to decline with depth as fracture apertures close. Figure 5.1 describes the range in estimated maximum CO₂ storage resource in the Sugarloaf Arkose of the Deerfield Basin as a function of total rock porosity at injection, ranging from 5% to 20%. Moreover, while the total area of the Sugarloaf Arkose available for CO₂ injection is 100 km², it is unlikely that in practice all of this area would be available for targeted CO₂ injection sites. Thus, Figure 5.1 also shows the theoretical storage resource in this formation as a function of area; if only small land areas were available targets for CO₂ injection, then the CO₂ resource in this formation decreases.

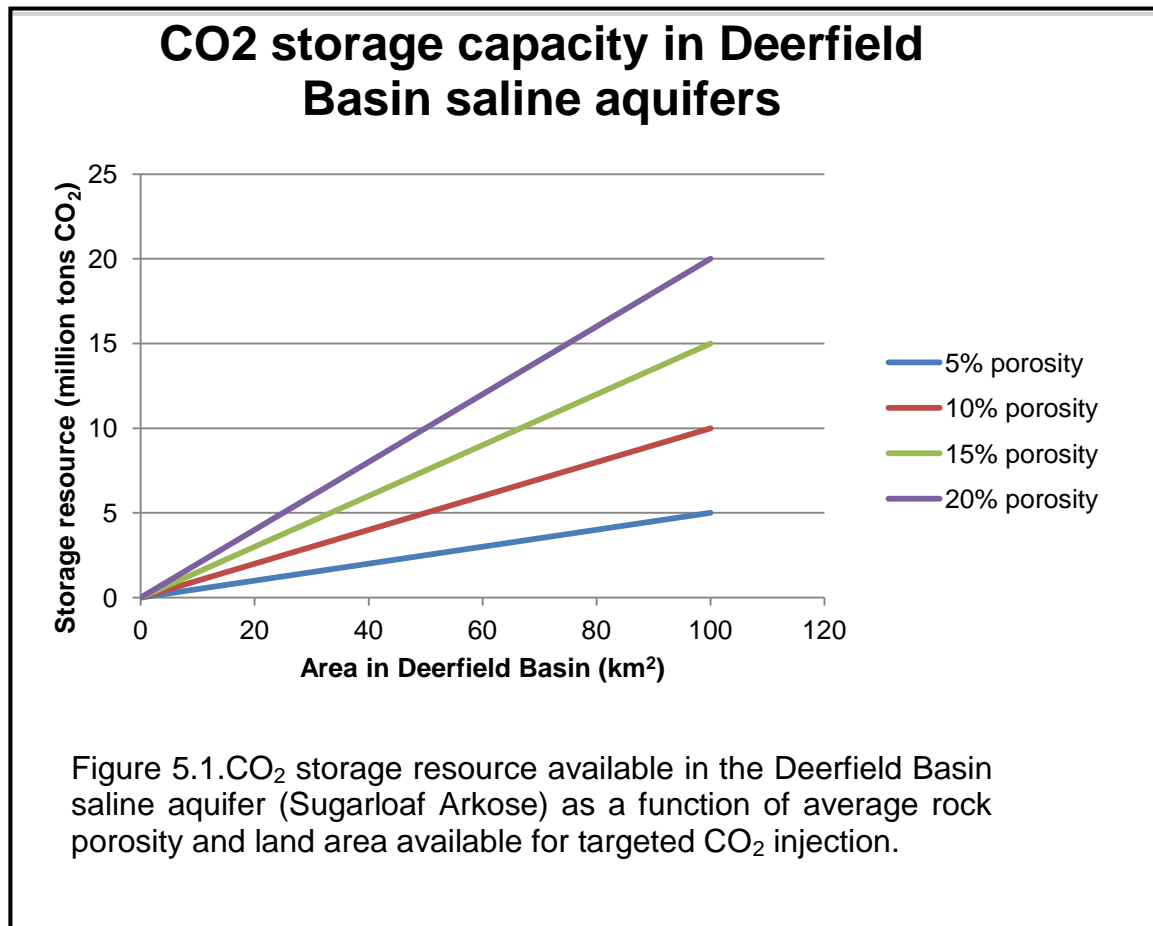
b. Hartford Basin, Sugarloaf Arkose

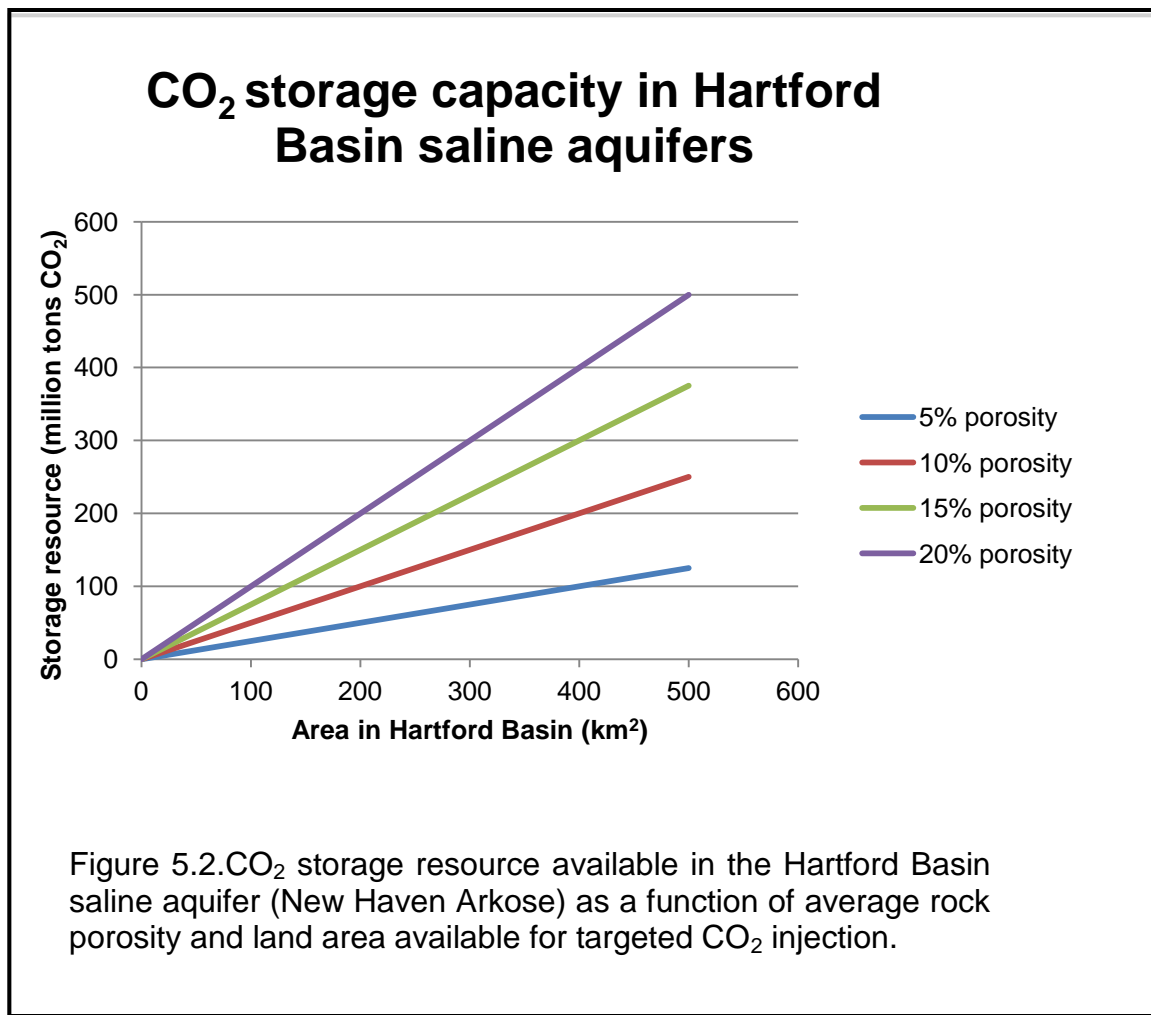
As described in Chapter 4, within the stratigraphy of the Massachusetts portion of the Hartford Basin, the New Haven Arkose is the most viable candidate for CO₂ storage. The input data for calculation of total CO₂ storage in this formation are:

area	A	500 km ²
formation thickness	h_g	500 m
density of supercritical CO ₂	ρ	500 kg m ⁻³
porosity	Φ_{tot}	5-20%
efficiency	E	2%

where 2% efficiency is the mean efficiency calculated by Bachu et al. (2008) for injection into saline aquifers based on a suite of Monte Carlo simulations of injection efficiency. The density of supercritical CO₂ varies with temperature and pressure; for this calculation, 500 kg m⁻³ is an approximate average density for the temperatures and pressures likely to be achieved in the Hartford Basin. Together, these data yield a maximum (theoretical) CO₂ storage resource in the Hartford Basin of **125 to 500 million tons CO₂** depending on rock porosity. This maximum resource potential is highly unlikely to be realized as true storage capacity, due to uncertainty in rock porosity and limitations in the actual land area that may be available for CO₂ injection. Porosity is uncertain for the New Haven Arkose at depths that would be targeted for injection; porosities in surface samples of this formation range between 15-20%, while porosity can be expected to decline with depth as fracture apertures close. Figure 5.2 describes the range in estimated maximum CO₂ storage resource in the

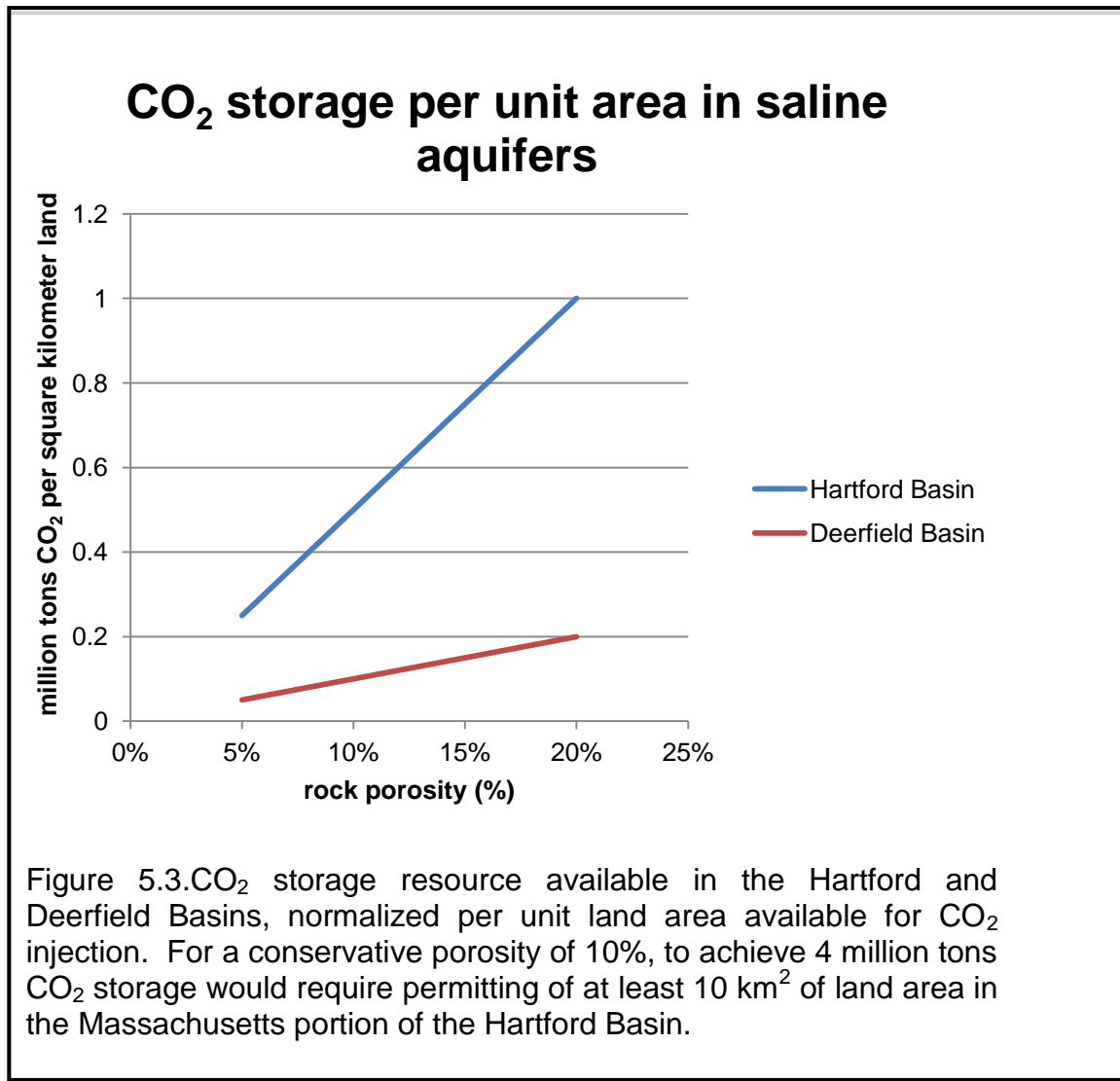
New Haven Arkose of the Hartford Basin as a function of total rock porosity at injection, ranging from 5% to 20%. Moreover, while the total area of the New Haven Arkose in Massachusetts available for CO₂ injection is 100 km², it is unlikely that in practice all of this area would be available for targeted CO₂ injection sites; much of the Hartford Basin in Massachusetts is overlain by the Springfield metropolitan area and this heavy development may preclude siting of injection wells. Thus, Figure 5.2 also shows the theoretical storage resource in this formation as a function of area; if only small land areas were available targets for CO₂ injection, then the CO₂ resource in this formation decreases.





c. Summary of CO₂ storage in saline aquifers of the Connecticut River Valley

As described in Chapter 4, it is likely but not certain that all screening criteria can be met for saline aquifers in the Deerfield and Hartford Basins. If these are met, then together the Sugarloaf and New Haven Arkose formations may demonstrate up to 130 million tons CO₂ (at low porosity of 5%) to 520 million tons CO₂ (at high porosity of 20%). However, even though these maximum theoretical resource estimates include an efficiency estimate that accommodates incomplete access of CO₂ to all pore spaces in the rock, it is still highly likely that only a fraction of these formations would be targeted for CO₂ injection well locations. A useful means to estimate more realistic CO₂ storage capacity in this region is to normalize CO₂ storage resource per km² of land area; in this way, stakeholders can better estimate theoretical maximum CO₂ storage that can be achieved for a given land area permitted for injection. Results of this calculation are shown in Figure 5.3 for both the Deerfield and Hartford Basins (Massachusetts portion) across a range of total rock porosities.



5.3 Estimate of CO₂ storage resource in unmineable coal seams

The volumetric equation to describe CO₂ storage resource in unmineable coal seams is:

$$G_{\text{co}_2} = A h_g C \rho_s E$$

Where G_{CO_2} is the mass of CO₂ that can be contained in the unit, A is the area of the storage basin, h_g is the composite thickness of coal seams within area A , C is the standard volume of CO₂ that can be stored in a volume of coal, based on Langmuir adsorption isotherms measured on the targeted coals, ρ is the standard density of CO₂ (1.873 kg/m³, used to convert CO₂ from volume units to mass units), and E is an efficiency factor estimated to reflect the subsurface volume of pores accessible to injected CO₂.

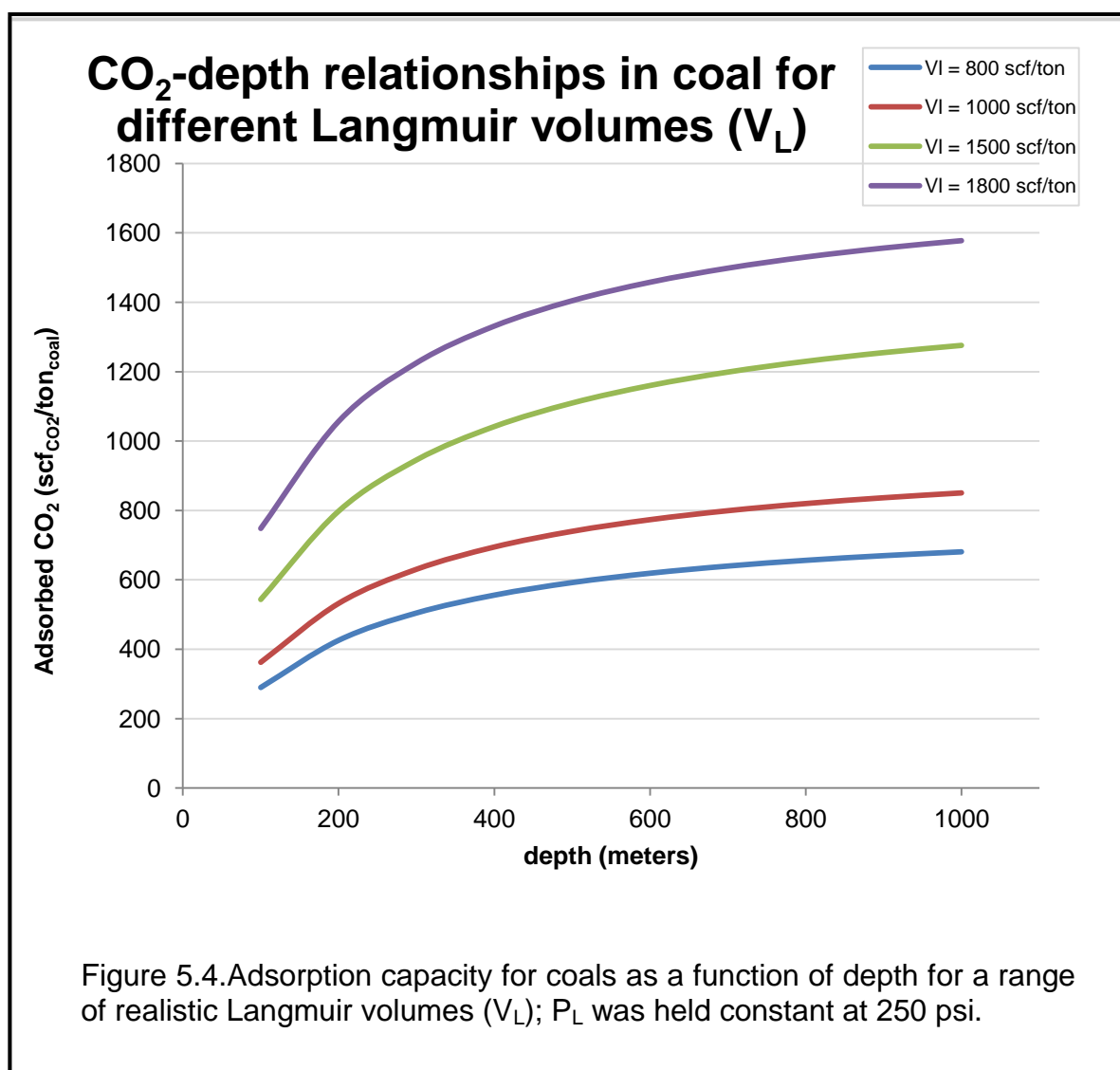
As described in Chapter 4, unmineable coals in the Rhode Island Formation of the Narragansett Basin in southeastern Massachusetts may hold potential as a CO₂ storage resource. The input data for calculation of CO₂ storage resource in these coals are:

area	A	100-300 km ² likely, up to 1000 km ² possible
formation thickness	h_g	1-10 m likely, up to 30 m possible
standard volume of CO ₂	C	24-58 m ³ CO ₂ /m ³ coal likely (<i>see below</i>)
standard density of CO ₂	p_s	1.873 km m ⁻³
efficiency	E	33%

Although both area and coal thickness are uncertain, it is the standard volume of CO₂ that can be adsorbed into the coal that is potentially the most variable in this setting. Standard CO₂ volumes in adsorption are described by a Langmuir adsorption isotherm. Adsorption capacity of gases is temperature dependent, and follows a Langmuir pressure-dependent isotherm relationship in which gas adsorption capacity increases with increasing applied pressure asymptotically up to a maximum capacity termed the Langmuir volume. The general relationship for gas adsorption is:

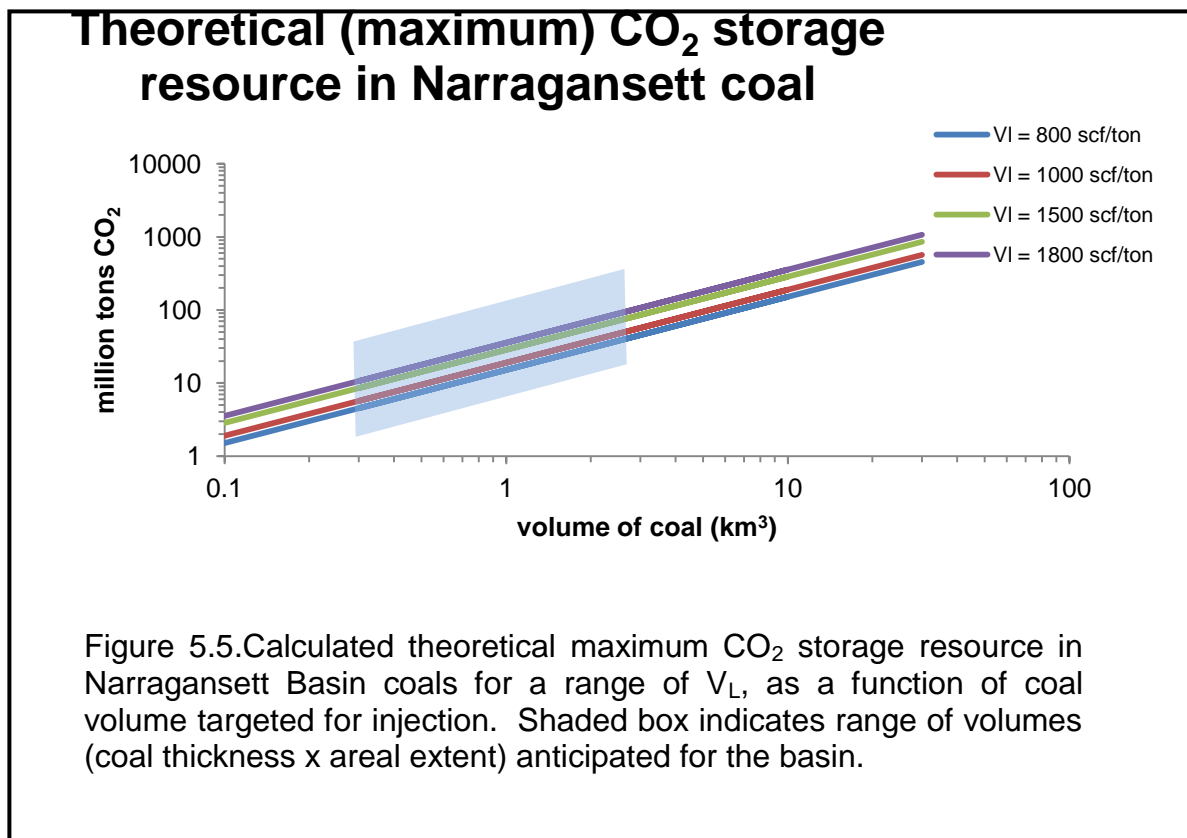
$$C = P * V_L / (P + P_L)$$

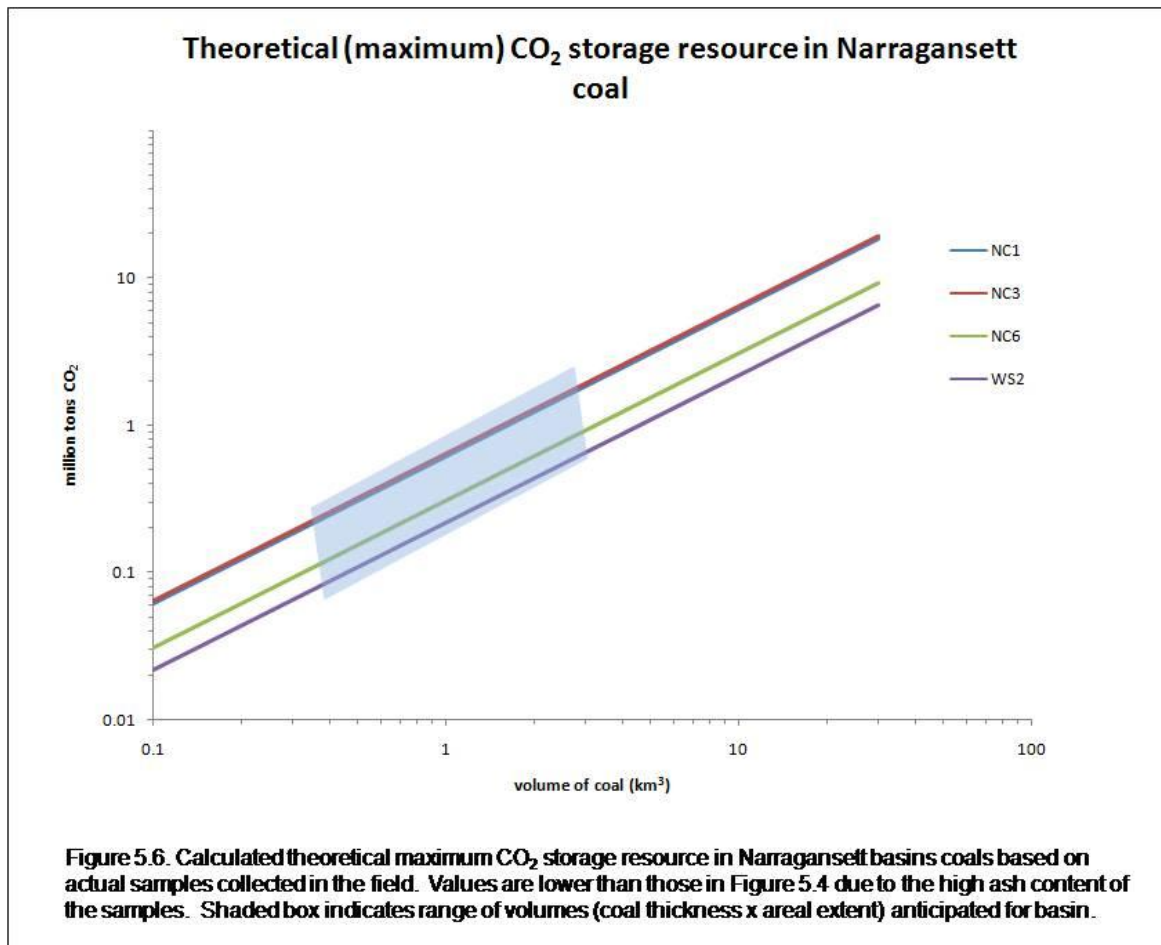
Where **C** is the volume of gas adsorbed, **P** is the applied pressure, **V_L** is the Langmuir volume and **P_L** is the Langmuir pressure. Both **V_L** and **P_L** can be obtained experimentally from measurement of the mass (or volume) of adsorbed gas as a function of applied pressure. As pressure is applied, the mass (or volume) of adsorbed gas asymptotically approaches a constant value, **V_L**, while **P_L** is mathematically defined as the pressure at ½ of **V_L**. Although adsorption isotherm data are not available for pristine coals from the Narragansett Basin, the data of Buruss (2003) can be used as a guide (see Figure 4.1). From this figure, the best-fit isotherm line to these data yields **V_L** of 1800 scf/ton and **P_L** of 250 psi. These Langmuir volumes and pressures are similar to (but slightly higher than) values reported for other high-rank coals by Krooss et al. (2002) and Laxminarayan and Crosdale (1999), as well as data from a study of lower rank coals by Bachu (2007). For a given Langmuir volume and pressure, however, the actual adsorption capacity of the coal will be dependent on the applied pressure. Pressures at the depths that may be targeted for CO₂ injection in the Narragansett Basin are unknown, but likely reflect prevailing hydrostatic pressure gradients; thus pressure is a function of depth into the basin. Figure 5.4 shows calculation of the CO₂ adsorption capacity on coals as a function of depth for a range of **V_L**; **P_L** was held constant at 250 psi for these calculations. Given that ash content and wetness will tend to decrease adsorption capacity, **V_L** in the range of 1000-1500 scf/ton are reasonable estimates of Langmuir volumes for high-rank anthracites and values of 35 scf/ton are reasonable as a minimum value for coals in the Narragansett Basin. Note that for depths greater than 600 meters, adsorption capacity is nearly constant for a given **V_L**. As described in Chapter 4, injection targeted in coals would be limited to depths above 1000 meters, below which permeabilities decline below threshold screening criteria values. Injection is also unlikely above 500 meters, as salinities may not be above threshold values and adsorption capacities are low due to lower hydrostatic pressures.



To calculate CO₂ storage resource in coals of the Narragansett Basin, adsorption capacities at 600 meters depth were used, as only slight increases in adsorption capacity are calculated between 600 and 1000 meters depth. Estimates of the area of coal in the basin range between 100-1000 km², while estimates of coal thickness range between 1-30 meters composite. Together, these ranges define a potential volume of coal of between 0.1 and 30 km³ that may be available for injection in the Narragansett Basin. The total theoretical CO₂ storage resource for this range in volume is shown in Figures 5.5 and 5.6 for a range of likely coal Langmuir volumes, using each V_L to calculate an adsorption capacity at applied pressure equivalent to 600 meters depth in the formation. Figure 5.5 shows the expected theoretical storage for typical anthracitic coals from analogous basins. Figure 5.6 shows the expected theoretical storage for the high-ash content samples collected from the Narragansett basin. Conservatively, the total volume of coal is likely to be towards the low end of this volume range (shown by the shaded box in the figure), reflecting thinner-than-average coal seam thicknesses and lower-than-estimated areal extents of coal. Using most-likely V_L (1000-1500 scf/ton), from analogous basins, thickness (1-10 meters) and area (100-300 km²) estimates, the coals represent a theoretical CO₂ resource of between **2-100 million tons CO₂**. This represents storage of between 15-350 kilotons CO₂ per square kilometer of land. In contrast, the samples collected from the

Narragansett basin (NC1, NC3, NC6) show a theoretical storage of **0.1-1.1 million tons CO₂**. This represents about 1.0-3.7 kilotons of CO₂ per square kilometer of land.





5.4 Storage in basalt, shale and organic-rich schists

Because no methodology has been developed, no effort was made to calculate potential CO₂ storage in other geologic formations in Massachusetts beyond (i) saline aquifers in the Connecticut River Valley, and (ii) coals of southeastern Massachusetts. As described in Chapter 4, however, shales, schists and basalts represent potential CO₂ resources for the state. As methods become available to estimate CO₂ storage potential in these geologic formations, calculations should be applied to estimate CO₂ storage in (i) organic-rich shales in the Connecticut River Valley, (ii) basalts in the Connecticut River Valley, and (iii) organic-rich schists in the Berkshire Hills.

However, as an additional step, samples of the Walloomsac formation were collected and one sample (WS2) was analyzed for carbon adsorption potential (Appendix 1). Results indicate a Langmuir adsorption capacity of 11 scf/ton, which is very low and reflects the low organic content of the rocks. Due to the disconnected and contorted structure of the Walloomsac formation and low adsorption capacity no additional calculations on storage were done.

In addition, Massachusetts basalts show some promise for adsorption of CO₂. Therefore, additional experiments on the feasibility of using crushed basalt as a medium to convert CO₂ to stable

carbonate minerals are underway. Benchtop experiments using different pressures, temperatures, and grain sizes are being conducted to determine the optimum adsorption conditions. The results of these experiments will be presented in a separate, supplemental report when complete.

Chapter Six

Summary and Recommendations

This report on the development of an assessment of potential CO₂ storage resources in Massachusetts reveals that geologic CO₂ storage potential does exist in two geologic formations: sandstones in the Connecticut River Valley and unmineable coal seams in southeastern Massachusetts. There are established methodologies to estimate storage resource potential in these two formations. In the Connecticut River Valley, saline aquifers in the Deerfield and Hartford Basins may represent up to 520 million tons CO₂ as a storage resource; of this, 20 million tons is assigned to the Deerfield Basin while 500 million tons is assigned to the Massachusetts portion of the Hartford Basin. These are maximum storage capacity estimates, based on the unlikely persistence of 20% porosity throughout the targeted sites for CO₂ injection in both basins. More conservative estimates of 5% rock porosity result in lower calculated storage capacity of 130 million tons CO₂. The difference between these two basins derives from the 5-fold greater thickness of sandstone aquifer in the Hartford Basin (500 meters) versus the Deerfield Basin (100 meters), and the 5-fold greater area of potential CO₂ storage in the Hartford Basin (500 km²) versus the Deerfield Basin (100 km²). Nonetheless, CO₂ storage resources in the Hartford Basin may be difficult to realize given the more intensive urbanization in this region compared to the Deerfield Basin.

In southeastern Massachusetts, unmineable coal seams in the Narragansett Basin may represent up to 1000 million tons of CO₂ storage potential, depending on coal seam thickness, extent and adsorption capacity assumed from coals in analogous basins. However, this estimate is at the upper limit of expected coal thickness (100 meters) and formation extent (1000 km²); more conservative estimates of coal thickness (1-10 meters) and formation extent (100-300 km²) reduce this estimate of effective storage resource to between 2-100 million tons CO₂. The lower limit of storage potential based on adsorption capacity data from actual samples collected in the Narragansett basin is 0.1-1.1 million tons CO₂.

However, some key information required to evaluate key screening criteria and input volumetric data is lacking for these candidate geologic formations. The key data gaps are as follows:

1. 10,000 ppm TDS threshold—There are no wells that penetrate deep enough into either the Connecticut Valley or Narragansett basin to determine the depth at which the 10,000 ppm threshold is exceeded.
2. In situ porosity and permeability data— There are no in situ porosity or permeability data available from the rocks within the deep aquifers of the Hartford and Deerfield basins.
3. Connecticut Valley stratigraphy and architecture — There are no corehole or stratigraphic data available at depth to describe the tops or thicknesses of key stratigraphic units including caprocks. In addition, no data exist indicating the depth to the bottom of the basin or the presence of faults that may act as barriers to lateral CO₂ migration.
4. Narragansett Basin stratigraphy and architecture — There are no corehole or stratigraphic data available at depth to describe the tops or thicknesses of the coal seams and other stratigraphic units.

In order to establish if sandstone aquifers and unmineable coal seams present viable candidates for geologic carbon storage in Massachusetts, the following are recommended for future research:

1. Collect additional research on the porosity, permeability and total dissolved solids content of other analogous rift basins to refine estimates for the Connecticut Valley.
2. Perform laboratory tests of CO₂ adsorption potential (Langmuir volumes) for coals collected from depth in the Narragansett Basin.
3. Conduct deep drilling into sandstone aquifers in the Hartford and Deerfield Basins (>1000 meters depth) and into the Rhode Island Formation in the Narragansett Basin along the axes of anticlines, to verify if deep formation waters are sufficiently saline to meet EPA UIC threshold salinities of >10,000 ppm total dissolved solids. Salinities can only be inferred, and not confirmed, by comparison with other basins.
4. Determine estimates of the permeability in deeply-buried sandstones in the Hartford and Deerfield Basins, through pilot-scale deep drilling and injection tests.
5. Perform coring along the axes of anticlines in the Narragansett Basin to establish the individual and composite thickness of coal beds available for CO₂ injection
6. Conduct deep seismic reflection surveys of the Connecticut River Valley sedimentary basins and coal measures of the Narragansett Basin, to establish deep basin structure and architecture down to 5 km depth.

Other potential geologic formations in Massachusetts (organic-rich shales, basalts, and graphitic schists) have no established methodologies for estimating storage resource potential, and thus cannot be evaluated for CO₂ storage resource potential at this time. However, additional work was performed to begin the evaluation of these geologic formations in anticipation of the development of assessment methodologies.

7. Samples of the graphitic schists from the Walloomsac Formation were collected and laboratory tests conducted to determine the potential CO₂ adsorption capacity. The adsorption capacity is about 11 scf/ton. Though specific methodologies have not been developed for carbon-bearing metamorphic rocks, adsorption capacity is likely to be a variable that will be needed in the calculations.
8. Samples of the Holyoke, Hampden and Deerfield basalts were collected. Whole rock chemical analyses have been run to determine chemical composition. Laboratory experiments were completed to evaluate the propensity of these basalts to convert CO₂ to carbonate mineral precipitate. Results will be forthcoming in a follow up report.

Chapter Seven

Implication of Results and Next Steps

The unmineable coal beds of the Narragansett Basin and the deep saline sandstone deposits of the Connecticut Valley show estimated carbon storage potentials of 0.1-100 million tons and 130 million tons, respectively. Estimates from the U.S. EPA¹ indicate carbon emissions for Massachusetts in year 2007 totaled approximately 88 million tons. If all the annual carbon emissions could be captured and all the available storage utilized the repository would last about 1.5 to 2.5 years.

Table 7.1 provides a breakdown of 2007 carbon emissions from various sectors of the Massachusetts economy and the estimated years of storage available for each. Electric power generation accounts for approximately 29% of all carbon emitted. Recognizing that capturing and storing carbon from the residential and transportation sectors is unrealistic, storing carbon emissions from selected electric power generating stations (as well as larger commercial and industrial complexes) located in close proximity to the Narragansett Basin and Connecticut Valley may warrant closer examination.

Table 7.1. Carbon dioxide emitted from various sectors of the Massachusetts economy.

Sector	Million tons of CO ₂ emitted	Percent of Total	Life Span of Storage (yrs) ^a
Commercial	5.79	7	22-40
Industrial	5.14	6	26-44
Residential	14.84	17	9-15
Transportation	36.54	41	4-6
Electric Power	25.77	29	5-9
Total	88	100	

^aCalculated by taking the minimum total storage capacity (130.1 million tons) and maximum total storage capacity (230 million tons) and dividing by the annual tons of CO₂ emitted.

For example, in the Narragansett basin area total carbon emission from existing power stations (Bellingham, Blackstone, Brayton Point, Dartmouth, Dighton and Somerset) is approximately 10.177 million tons based on data from MA DEP², with Brayton Point comprising nearly 66% of the total. Accordingly, the possible life span for storage in the unmineable coals ranges from 3.5 days to 10 years. Life span of storage from Brayton Point alone, a coal-fired plant, is approximately 6 days to 16 years.

By analogy, total estimated carbon emission from the Mount Tom (coal fired) and West Springfield plants in the Connecticut Valley is 1.172 million tons with Mount Tom comprising 90% of the total. Both plants are proximal to the Hartford basin with an estimated conservative storage capacity (5% porosity) of 125 million tons. This results in a life span of approximately 107 years.

It is not known if these life expectancies make carbon capture and storage economically feasible in Massachusetts. That determination is beyond the scope of this project. However, there are several critical steps that must be considered in order to determine feasibility that have significant cost

¹http://www.epa.gov/climatechange/emissions/state_energyco2inv.html

²<http://www.mass.gov/dep/air/climate/machaver.pdf>

implications. These steps can be broken down into two main categories, site characterization and conveyance system construction and permitting.

Site Characterization

Step 1. The most critical step needed is to drill at least two holes, one in each basin, to determine the stratigraphy and water quality as a function of depth. If the necessary cap rocks are not present and the water quality does not exceed a salinity of 10,000 ppm in the target formation, then carbon capture and storage is not feasible. Assuming both criteria are met, the holes should be logged geophysically with optical televiewer, acoustic televiewer, caliper, temperature, gamma and fluid conductivity to better define the stratigraphy. Furthermore, additional samples of coal collected at depth are needed and testing completed to determine the full range of CO₂ adsorption capacities for the Narragansett coals. Approximately \$1 million should be reserved for Step 1.

Step2. Very little is known about the lateral extent of the various stratigraphic units and their spatial arrangement. Many open and important questions remain. For example: How continuous are the beds in a lateral and vertical direction? How much are the beds dipping? Are there faults and other stratigraphic discontinuities? These questions can be addressed by an aggressive surficial geophysical survey program using seismic reflection and other techniques. Geophysical surveys would provide a better 3-dimensional picture of the geology and allow more precise identification of possible targets for carbon storage. Approximately \$5 to \$10 million should be reserved for this phase of work.

Step 3. Once possible targets are identified, additional drilling will be required to verify the subsurface structure and geology. This should be accompanied by in situ downhole testing to determine formation porosity, permeability, adsorption capacity, injectivity, cap rock integrity, among other considerations. The step should reserve \$5 to \$10 million for borehole testing.

Step 4. The last step in site characterization is to conduct a pilot study at a selected site. This would consist of: 1) drilling an injection well into the target formation and running geophysical surveys to prepare for injection testing; 2) Running an injection test, first with brine then with CO₂; and, 3) conducting post-injection monitoring over a period of several years including after well sealing and abandonment. Approximately \$8 to \$10 million should be reserved for the pilot study. The western Kentucky carbon storage pilot study installed an 8,126 foot hole. Estimated costs are \$8 million for the hole, injection testing and monitoring.

Conveyance System and Permitting

Another major cost is capturing the carbon dioxide and transmitting it from the source to the injection site. Conceptual cost estimates³ for pipelines based on 2008 pricing are on the order of \$0.5 million per mile. Added on top of that is the cost of permitting, which will be considerable in Massachusetts. Furthermore, Massachusetts is the third most densely populated state in the U.S. Construction of pipelines to convey CO₂ will be a formidable political challenge as well.

³Nick Tew, State Geologist of Alabama, personal communication, June 30, 2008

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Appendix 1

Adsorption Isotherm Study

Note: Sample WS2 is graphitic schist from Pittsfield, MA; all other samples are Narragansett coals