Characterization and Modeling of the Broom Creek Formation for Potential Storage of Co_2 from Coal-Fired Power Plants in North Dakota

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Introduction

Future fossil fuel-based energy production facilities may include carbon management strategies as part of their overall operational plans. Storage of produced carbon is an important part of these strategies. Geologic formations have been demonstrated to be good locations for large-scale fluid storage as they have been used for decades to store natural gas and dispose of acid gas, produced water from oil and gas operations, and hazardous and non-hazardous wastes. Of all possible options for geologic storage of carbon dioxide (CO_2), brine-saturated formations (often referred to as "saline aquifers") have been identified as having the highest potential storage capacity [Bachu and Adams, 2003; IPCC, 2005]. These formations are commonly found in sedimentary basins and often have properties favorable for fluid injection. However, when considering a formation as a target for CO_2 storage, it is necessary to ensure permanent trapping of the fluid. Thus, the chosen formation should have adequate porosity, permeability, temperature and pressure conditions, and a competent seal. This paper describes an approach to choosing and characterizing a target formation for CO_2 storage. The study is a part of the Plains CO_2 Reduction (PCOR) Partnership Program, which in turn is a part of the US Department of Energy Regional Carbon Sequestration Partnership (RCSP) Program. The PCOR has a very practical goal of providing regional industry with high quality information for making decisions regarding carbon management.

The presented approach utilizes a step-wise procedure for the "bottom-up" analysis of a sequence of sedimentary rocks in a specific geographical location and includes the following steps: 1) screening of the local aquifer systems; 2) choosing aquifers that have a combination of high storage capacity and effective trapping mechanism; 3) using available geological and geophysical data and obtaining new data for building a petrophysical model of the system; and 4) considering different injection scenarios to predict the fate of the injected CO_2. The subsequent sections of the paper detail the steps of the procedure and present the results of a case study conducted in the North Dakota portion of the Williston Basin. Specifically, the case study focused on an area of approximately 182 square miles in the vicinity of the town of Washburn in central North Dakota. This area was chosen for the case study because of the presence of several coal fired power plants near Washburn, some of which may be seeking suitable locations for CO_2 storage in the future.

Screening of the aquifer systems

The initial step in the Washburn study consisted of collecting available data relevant to the hydrogoelogical characteristics of regional saline aquifer systems; oil, gas and water well data; and existing geographic information system (GIS) map data. In this way, evaluation of three major aquifer systems, which were identified as being potentially suitable for CO_2 storage, was conducted. The systems are the Lower Cretaceous aquifer system, the Permian-Pennsylvanian Minnelusa Group, and the Mississippian Madison Group. All of the identified systems have high potential to store CO_2 because of their significant areal extent, competent cap rocks and substantial porosity and permeability. Thus, reconnaissance level evaluation of the systems was conducted [Sorensen et. el., 2005]. The evaluation consisted of collecting geological, hydrological and petrophysical data. Digital maps of the aquifers, specifically structural and thickness-porosity maps were created and allowed for better understanding of the most promising injection zones. However, the initial reconnaissance screening did not include creation of a detailed geologic model of the systems.

Choosing the primary target formation

The reconnaissance level study has indicated that the Broom Creek Formation within the Minnelusa Group has the highest thickness of porous reservoir rock of all the studied aquifer systems in the Washburn area with relatively few interbeds of lower permeability rocks. This property of the formation combined with favorable petrophysical properties, appropriate formation water chemistry, and a competent seal provided by the directly overlying Opeche Shale, makes the Broom Creek Formation the best target horizon for large-scale saline aquifer storage of CO_2 in the central part of the Williston Basin. Thus, a more detailed study was conducted for selected parts of the aquifer. The study followed the best practices for creating a petrophysical model of a geologic system commonly used in the oil and gas industry for hydrocarbon exploration and production planning. The exact locations for the case studies are chosen basing on the proximity to the major sources of CO_2 and favorable reservoir properties. Figure 1 shows the locations of the sources and the study area.

Creating a petrophysical model of the system

Several areas within the Broom Creek formation were studied in details. The methodology used is illustrated by an example characterizing the Washburn study area. As indicated by Figure 1 major sources of CO_2 are located in the area. The sources include six power generating and three fuel processing facilities. After reviewing geophysical data available for the area the study focused on two sites, a northwestern (NW) and a southeastern (SE), as being most appropriate for CO_2 injection. The sites are shown in Figure 2. They were selected because of the following characteristics:

- combination of thick reservoir with good porosity;
- relatively dense grid of wells serving as sources of geophysical log data; and
- availability of core data.

For the NW site an area of approximately 182 square miles was characterized using log data from 10 wells. The following types of log data were available: gamma ray, resistivity, porosity and compensated neutron density. Figure 3 presents a stratigraphic sequence of rocks within the Minnelusa Group based on logs. As illustrated in Figure 3, the reservoir rock consists of Upper and Lower Broom Creek sandstones. The reservoir rock is capped by low permeability shales, siltstones and limestones of the Spearfish and Opeche Formations. Nearly impermeable anhydrite of the Amsden Formation underlies the targeted injection zone. Wire-line logs from the 10 wells in the study area were correlated. Petrel software provided by Schlumberger was used in all steps of the model building process. Structure maps for the top of each zone shown in Figure 3 and for the base of the Lower Amsden unit were created and then utilized for building the frame of the 3D geologic model of the Broom Creek aquifer system. Internal layers were then added to capture the variability in reservoir properties evidenced in the well logs. The complete model had about 410,000 cells with dimensions of 1000 feet in the two horizontal directions. Average cell thickness was 12 feet and ranged from 5 to 23 feet.

The next stage of model development was populating the geologic model with petrophysical properties. Given the sparse well data (ten wells in 182 square miles), to ensure that uncertainties in reservoir properties were adequately captured the decision was made to populate the model with low, mid, and high case estimates of porosity and permeability. Broom Creek core data was available from one well, the ANG #1, in the Washburn Study Area. Log data on rock porosity was correlated to measured core porosity data (Figure 4) from this well. The correlation allowed for creating an empirical relationship (1) between the porosities.

(1) $\varphi_{core} = 0.3427\varphi_{log} + 13.696$

This correlation indicates that for log derived porosity φ_{log} greater than 20%, log porosity is more optimistic than measured core porosity φ_{core}. For the Broom Creek Formation in the base case model, porosity was first distributed in the model by SGS (sequential Gaussian simulation). A second step was then undertaken, when the resulting porosity in the model exceeded 20%, equation (1) was used to recalculate the porosity in that cell. Two other models were created: low and high case porosity models. On average low case porosity was 15% lower and high case porosity was 7% higher than that of the base case. Probability distribution function for the porosities was obtained empirically from geophysical logs and core data.

Core porosity and permeability data for Spearfish and Broom Creek Formation were analyzed to derive the relationship between rock porosity φ_{core} and permeability k. The cross plots of porosity and permeability along with the suggested trend lines are shown in Figure 5a,b.

The trend lines shown in Figures 5a and 5b represent high case (blue lines), mid case (black lines) and low case (green lines) permeability approximations. The empirical formulae for the trend lines are given in Table 1. No core data is available for the Opeche or Amsden Formations. Therefore permeability of the Opeche Formation was assumed to be similar to that of the Spearfish formations and the low, mid and high case permeability transforms developed for the Spearfish Formation were also used for the Opeche. For the upper anhydrate zone within the Amsden Formation low, mid and high permeability values of 0.001md, 0.1md 0.5 md. respectively were assigned. Permeability in the remaining Amsden layers was assigned using the transforms derived for the Spearfish Formation. Permeability distribution within the model was specified by applying the transforms to the values of porosity which have been prescribed earlier. Figure 6 illustrates the resulting mid case permeability distribution within the model.

Broom Creek Formation pressure p, psi, and temperature T, ^{0}F, distributions within the model were assigned by calculating the measured depth D of each cell and applying standard gradients in the area. The formulae for pressure and temperature are

$p = 14.7 + 0.4616D$,

$T = 43.5 + 0.0123D$

The final step in the creation of the model was the determination of water saturations and salinity from resistivity logs. The following commonly used formula (e.g. [Hilchie, 1982]) was used to estimate water resistivity R_w from resistivity R_t measured by wire-line logging.

$R_w = 1.23R_t\varphi^2$

Estimated resisitivity of water was further used to estimate irreducible water saturation S_{wirr} and the salinity s_w of water. Usually the salinity of water is determined from graphs (e.g. [Hilchie, 1982]). However, the numerical model required an analytical relationship. Analysis of graphs presented in Hilchie (1982) yielded the following relationship

(2) $s_w = 4*10^5 T^{1.0145} R_w^{-1.1}$

The following formula modified from [Haro, 2004] served for prescribing irreducible water saturation.

(3) $S_{wirr} = 1/\varphi\sqrt{(}R_w/R_tT$

To populate the grid with salinity and irreducible water saturation the values for each well were calculated using formulae (2, 3) and then interpolated throughout the grid.

The resulting static model was then used to estimate the Broom Creek pore volume available for CO_2 storage and the volume of CO_2 that can be injected into the Broom Creek formation in the NW site of the Washburn study area. Table 2 presents the results for the three considered cases: low, mid and high.

Thickness-porosity map for the whole Washburn area (Figure 2) served for the estimation of the amount of CO_2 that might be stored in the area. Pressure and temperature data allowed for calculating CO_2 density ρ_{CO2} at reservoir conditions and the total mass Q_M of stored CO_2

$Q_M = V_{pore}*\rho_{CO2}E$

where E = 4% is the efficiency factor [RCSP, 2006]. Integration of Q_M over the area has yielded the total amount of CO_2 to be 5.2Gt. Figure 7 illustrates the storage potential in the Washburn area.

Injectivity of the formation and fate of CO_2

Mass Q_M reported in the previous section represents the ultimate amount of CO_2 that can be stored in the space provided by the pore volume for the accepted value of the efficiency factor. However, the amount of CO_2 that can be safely and economically injected into the formation should be estimated by running dynamic simulations for the different injection scenarios. The simulations are possible with the Petrel software and are an ongoing activity of the PCOR program. However, the simulations require significant modifications to the geologic model, which transform the geologic model into a reservoir model. This aspect is out of the scope of this paper and its progress will be reported separately.

Conclusions

- Rocks of the Minnelusa Group in the central part of the Williston Basin provide environment appropriate for storage of big amounts of CO_2. The amount of CO_2 that can be stored in the Washburn area is estimated to be 5.2 billion tons.

- The experience with creating the model indicated that data from existing oil and gas wells can be used for the thorough characterization of deep saline aquifers;

- The proposed approach allows for bottom-up analysis of the pore system; estimation of the pore volume available for CO_2 storage and of the amount of CO_2 that can be stored in the volume;

- The geologic model created using the described approach can be modified and serve for reservoir simulations and predicting the fate of the injected CO_2.

Reference

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Table 1. Suggested approximations for the relationship between porosity (fraction) and permeability *k*, md

	Spearfish/Opeche	Broom Creek
Low case approximation	$k = 3*10^{-5}\exp(44.365\phi)$	$k = 2.953*\exp(18.58\phi)$
Mid case approximation	$k = 7*10^{-4}\exp(42.656\phi)$	$k = 34.839*\exp(9.66\phi)$
High case approxiamtion	$k = 6.64*10^{-2}\exp(35.12\phi)$	$k = 22.044*\exp(13.23\phi)$

Table 2. Pore volume available for CO_2 storage in NW site of the Washburn study area

Pore volume distribution	Average porosity, %	Pore volume, ft^3	Pore volume, m^3
Low case	15.1	$2.21*10^{11}$	$6.26*10^{9}$
Mid case	16.8	$2.45*10^{11}$	$6.94*10^{9}$
High case	18.1	$2.65*10^{11}$	$7.50*10^{9}$

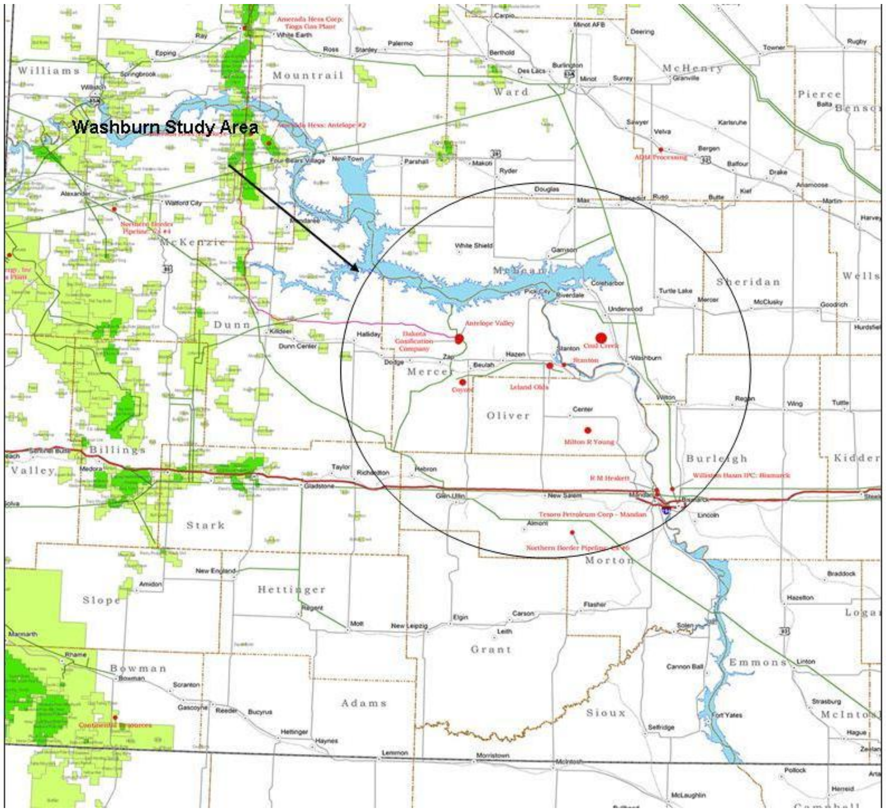


Figure 1. Location of the major sources of CO_2 in North Dakota

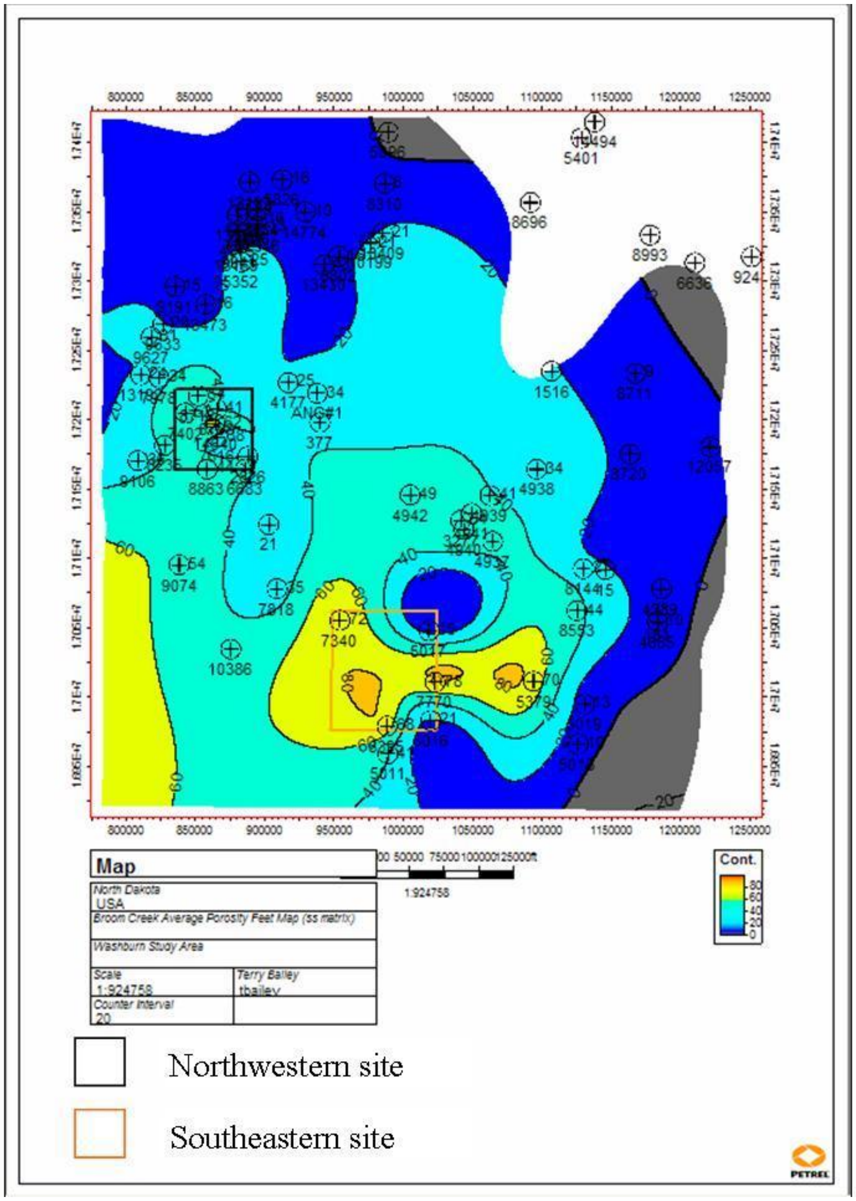


Figure 2. Thickness-porosity map of the Broom Creek Formation in the Washburn study area

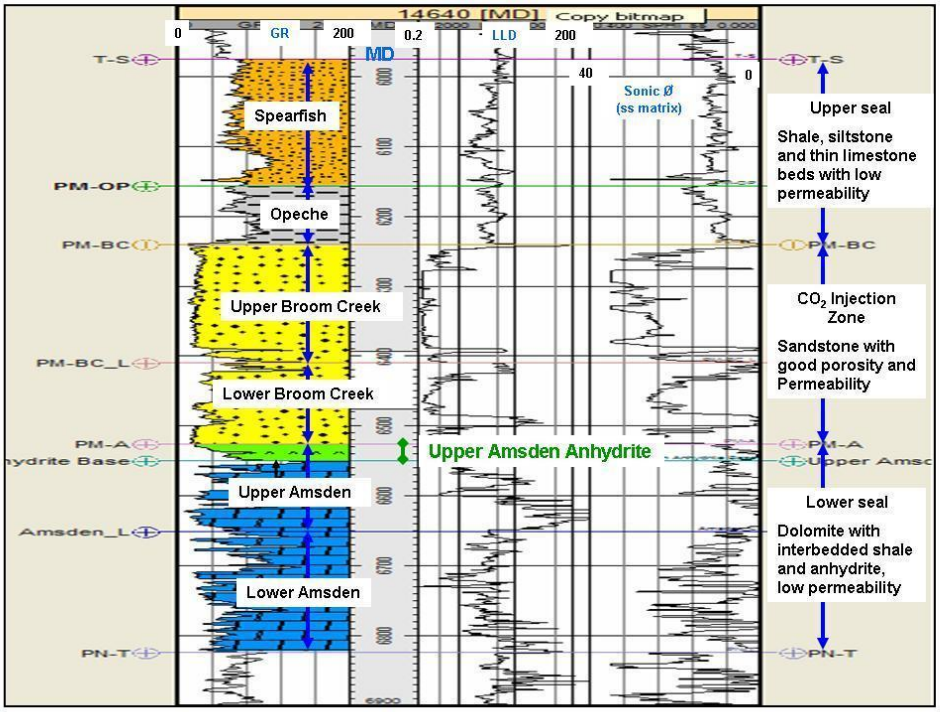


Figure 3. Stratigraphic sequence of formations within Minnelusa Group in Washburn study area

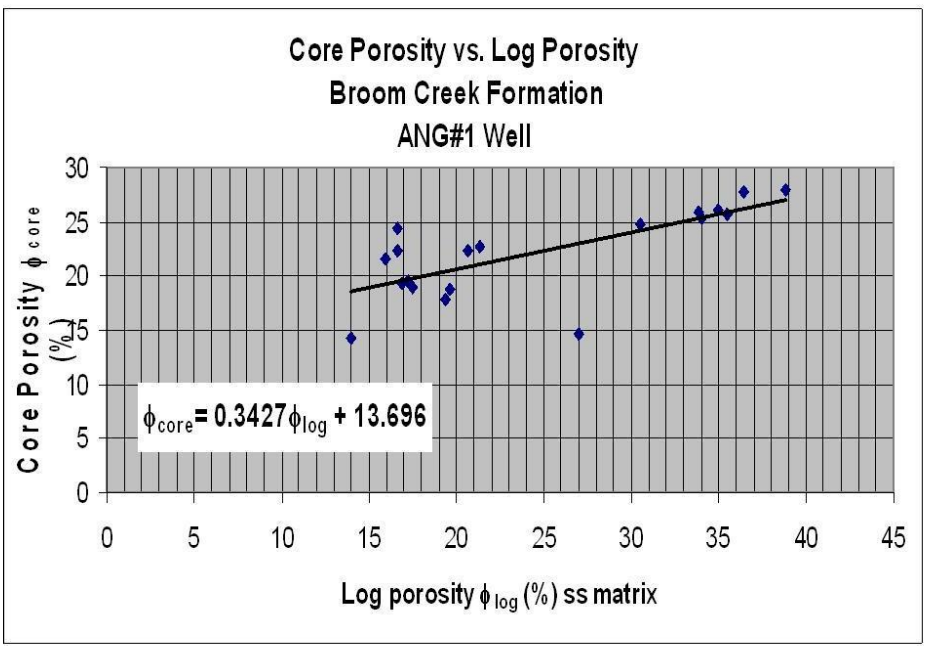
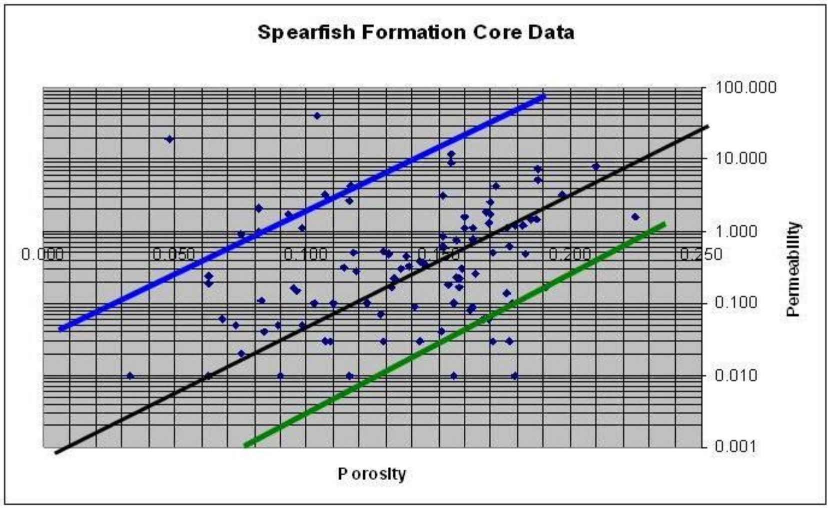


Figure 4. Correlation of log derived porosity to core derived porosity



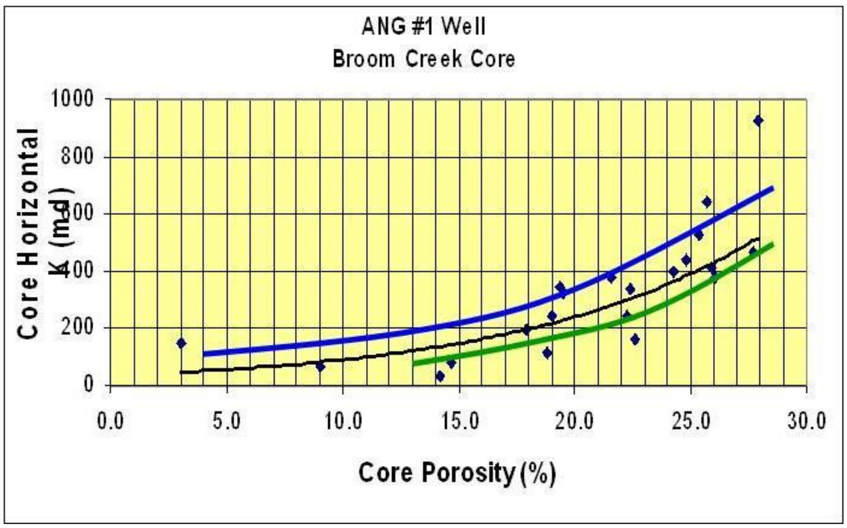


Figure 5. Porosity - permeability cross plots for a) Spearfish and b) Broom Creek cores

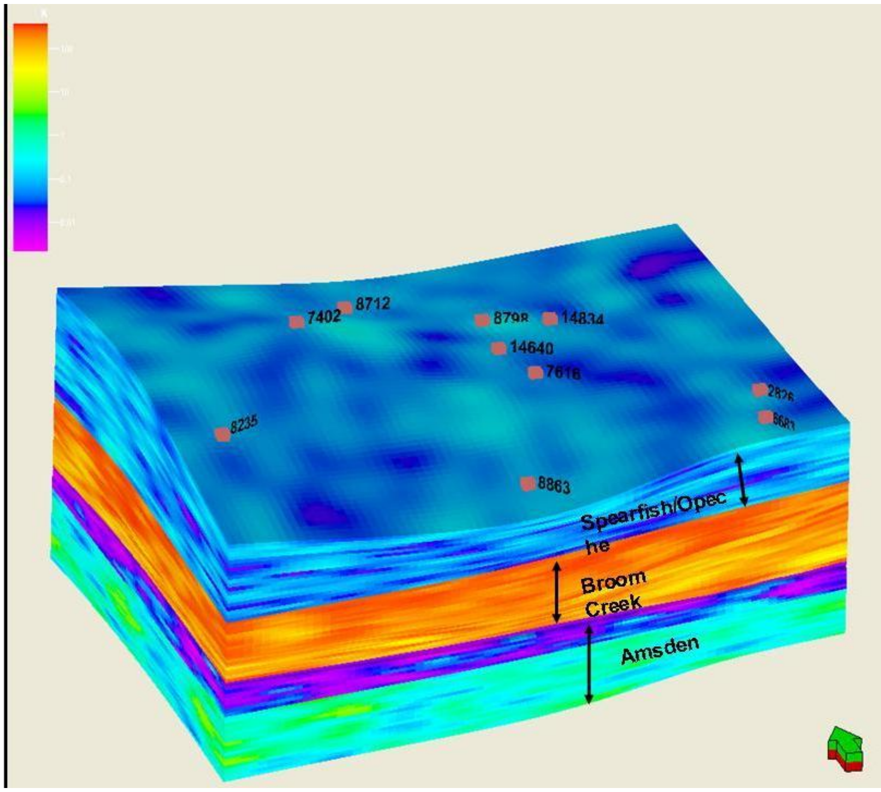


Figure 6. Mid case permeability distribution within geologic model for NW site of Washburn study area. Vertical exaggeration is 25

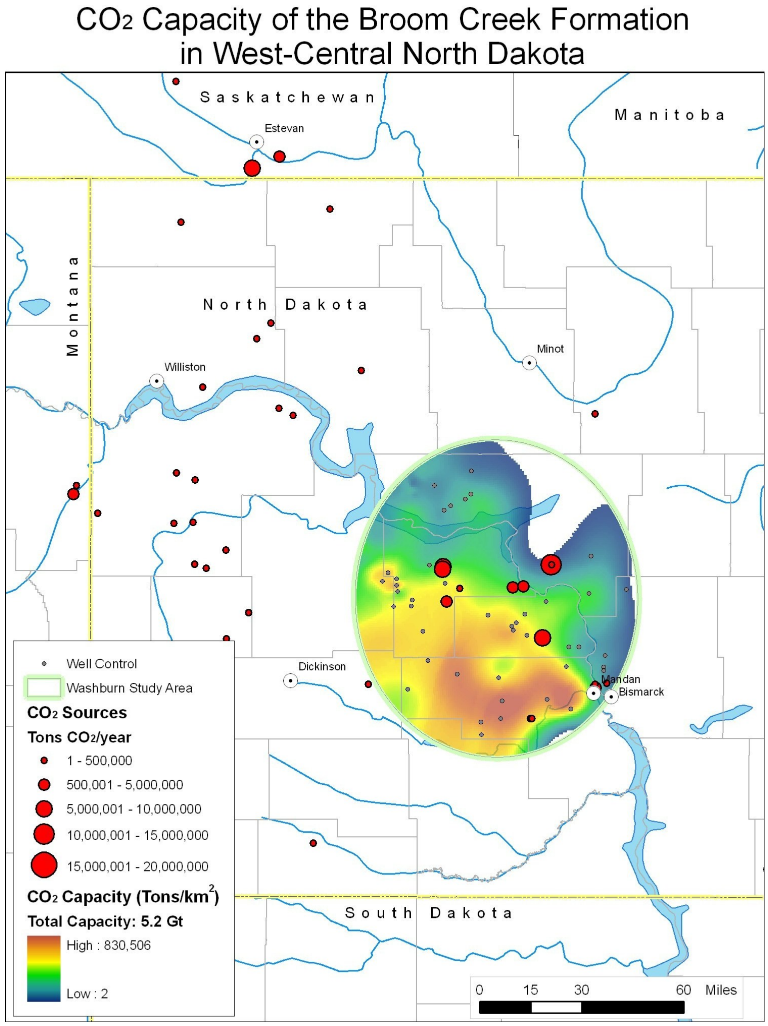


Figure 7. CO_2 storage potential in the Broom Creek aquifer in the bigger Washburn area