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ABSTRACT

Research involving management of carbon dioxide has increased markedly over the last decade as it relates to concerns over climate change. Capturing and storing carbon dioxide (CO_2) in geological formations is one of many proposed methods to manage, and likely reduce, CO_2 emissions from burning fossil fuels in the electricity sector. Saline formations represent a vast storage resource, and the waters they contain could be managed for beneficial use. To address this issue, a methodology was developed to test the feasibility of linking coal-fired power plants, deep saline formations for CO_2 storage, and extracting and treating saline waters for use as power plant cooling water.

An illustrative hypothetical case study examines a representative power plant and saline formation in the south-western United States. A regional assessment methodology includes analysis of injection-induced changes in subsurface groundwater chemistry and fate and transport of supercritical CO_2. Initial water–CO_2-formation reactions include dissolution of carbonate minerals as expected, and suggest that very little CO_2 will be stored in mineral form within the first few centuries. Reservoir simulations provide direct input into a systems-level economic model, and demonstrate how water extraction can help manage injection-induced overpressure. Options for treatment of extracted water vary depending upon site specific chemistry. A high efficiency reverse osmosis system (HERO™) shows promise for economical desalination at the volumes of recovered water under consideration. Results indicate a coupled use CO_2 storage and water extraction and treatment system may be feasible for tens to hundreds of years.

1. Introduction

In some regions of the United States, saline water-bearing formations have the potential to provide alternative sources to supplement growing water needs for all types of uses. At the same time, saline formations have captured the attention of CO_2 storage researchers, including those who developed the National Carbon Sequestration Database and Geographic Information System (NatCarb, 2008). A better understanding is needed of saline water resources when considering saline formations for both purposes. Injecting CO_2 into a saline formation may pressurize the saline formation and potentially alter formation properties and/or induce leakage if not properly managed. Coupling the pumping of saline waters, and so relieving overpressure, could become a potential solution, while at the same time providing a valuable resource if this water could be treated and made available for use in a power generating station (plant) for cooling purposes.

In this study, three linked areas of analysis address this multidisciplinary issue; a geotechnical assessment (subsurface geochemical and spatio-temporal reservoir modeling), a suite of water treatment options, and a systems-level analysis bring together physical and economic considerations throughout the geo- and power plant-system. One geotechnical question is whether injected CO_2 modifies groundwater chemistry to the point of influencing the economic viability of water treatment options. A critical issue is to ensure CO_2 will not be released once stored underground. A second issue to be examined is how the CO_2 storage system may be managed to minimize potential deleterious effects on the saline

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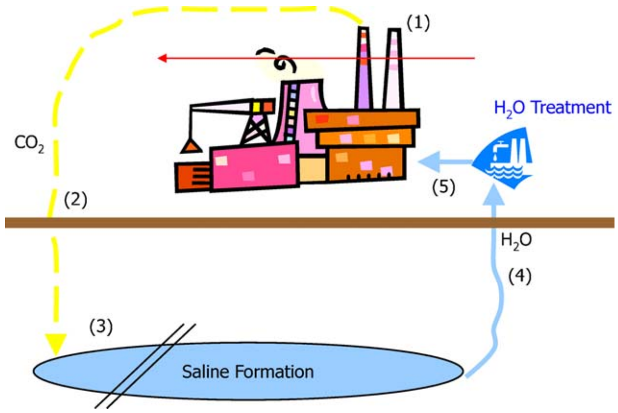

Fig. 1. The assessment methodology and model framework. (1) Power plant metrics, (2) CO_2 capture and storage system, (3) saline formation geotechnical modeling assessment, (4) water extraction analysis, (5) water treatment analysis for power plant cooling.

formation itself. The potential deleterious effects of injecting CO_2 into the saline formation may include a decrease in pH, a resultant increase in metal concentrations, and increased salinity due to the reaction of CO_2 with the saline formation minerals (Kharaka et al., 2006, 2009). Additionally, several water treatment and desalination issues need to be addressed as they relate to the quality of the treatment concentrate and disposal options. Each of these three areas of interest must be adequately addressed and integrated to determine the relative cost-effectiveness of using treated saline waters in power plant systems. Fig. 1 illustrates the overarching conceptual analytical framework for the analysis.

2. Methods

The analysis builds from the framework outlined in Fig. 1 by first selecting potential geological saline formations in the region that appear to meet a defined coupled-use criteria. The geochemical impact of CO_2 injection is determined from geochemical modeling using REACT (Bethke, 1998) coupled with knowledge of in situ pore water chemistry and formation mineralogy. Reservoir modeling using TOUGH2 (Pruess et al., 1999) investigates how a subsurface CO_2 plume may evolve over time, while additional analysis assesses the engineering and other resources required to develop a water extraction and treatment system. Finally, the analysis applies a working analytical economic-engineering systems approach to bring together and evaluate all of these components in a single integrated assessment model.

To address the multidisciplinary aspects of the analysis, a decision framework was developed to calculate both initial performance and economic uncertainty. Fig. 2 illustrates the underlying framework used to develop the integrated assessment model and the subsequent components outlined in Fig. 1.

The results of the saline formation evaluation include the illustrative levelized cost of electricity (LCOE), formation longevity for CO_2 capture and storage (CCS), extracted water (EW) budget, and additional system costs. The framework and subsequent integrated assessment are applied to a representative power plant based on the San Juan Generating Station (SJGS) and several saline formations within the San Juan Basin of northwestern New Mexico, United States.

This framework draws from the work of the larger CO_2 storage research community's guidelines and recommendations when addressing site screening, selection and characterization. Bachu and Adams (2003), for example, developed a detailed methodology to calculate the ultimate CO_2 storage capacity for saline formations. The United States Department of Energy (DOE) developed a national program to address regional considerations for CO_2 storage. Amongst seven designated regional carbon dioxide storage partnership programs, substantial siting and characterization methodological work was completed in the first phase of the efforts to develop the first Carbon Sequestration Atlas outlining a common methodology for capacity assessment for saline formations, depleted oil and gas fields, and coal seams. Following these efforts, the validation and development phases developed a plan to implement small-scale field tests and larger-scale projects to implement the down-select performed in the characterization phase (Klara et al., 2003; Litynski et al., 2008, 2009).

Additionally, many site-specific and general cases to store CO_2 in saline formations offer several lessons to build from regarding site selection, pressure management, and add to the growing body of literature as to the feasibility of storing CO_2 in saline formations (Lucier and Zoback, 2008; Nicot, 2008; Grataloup et al., 2009; Michael et al., 2009; Medina et al., 2011; Hovorka et al., 2000; Herzog, 2010). To potentially help guide the growing number of studies and projects, the International Energy Agency developed an overarching review of the risk assessment and terminology practices within the CO_2 storage community in an effort to help inform professionals working (or that may begin to work) in this applied field (IEAGHG, 2009).

3. Geologic background

For additional perspective regarding the San Juan Basin, Fig. 3 illustrates the region used throughout the decision framework and integrated assessment. The basin is a bowl-shaped structure formed in early Tertiary time (Paleocene to early Oligocene), during which it filled with several thousand feet of shallow marine and near shore deposits (the Fruitland coal-bearing formations and overlying Kirtland Formation, the latter being a potential barrier to the upward migration of CO_2 that might be stored in the Fruitland). Allis et al. (2003) offers a good characterization of the region.

The last deposits laid down prior to formation of the San Juan Basin were a thick sequence of Cretaceous shallow marine shales which are interbedded with occasional sandy layers reflecting the positions of former beaches. These sand units have relatively high permeability in some regions. At the base of this sequence lies the Dakota sandstone, below which lies the Jurassic Morrison Formation. Beneath this are still more alternating layers of sandstones, conglomerates, shales and limestones, including the Permian Hermosa limestone. The whole stack of sediments ultimately rests on a basement of very low permeability 'crystalline' Precambrian rocks (granite, gneiss, schist, etc.).

The SJGS is located on the western edge of the basin (Fig. 3). East of this site, wells several thousand feet deep would barely penetrate the Tertiary basin fills or late Cretaceous strata, while west of the site a similar well could penetrate much further down, perhaps all the way into Permian Hermosa Formation limestone.

4. Results

4.1. Evaluation criteria for saline formations

Two evaluation criteria for the region and its potential for coupled-use CO_2 storage and saline water utilization applications are proposed herein. First, saline formation water must be both available and treatable economically. Regulatory considerations for waters with less than 10,000 parts per million (ppm) of total dissolved solids (TDS) (e.g., 10,000 g of salt per 1,000,000 g of solution) dictate that these waters would likely not be considered for CO_2 storage (EPA, 2008). Additionally, economic desalination of saline waters may prove challenging for waters with TDS beyond

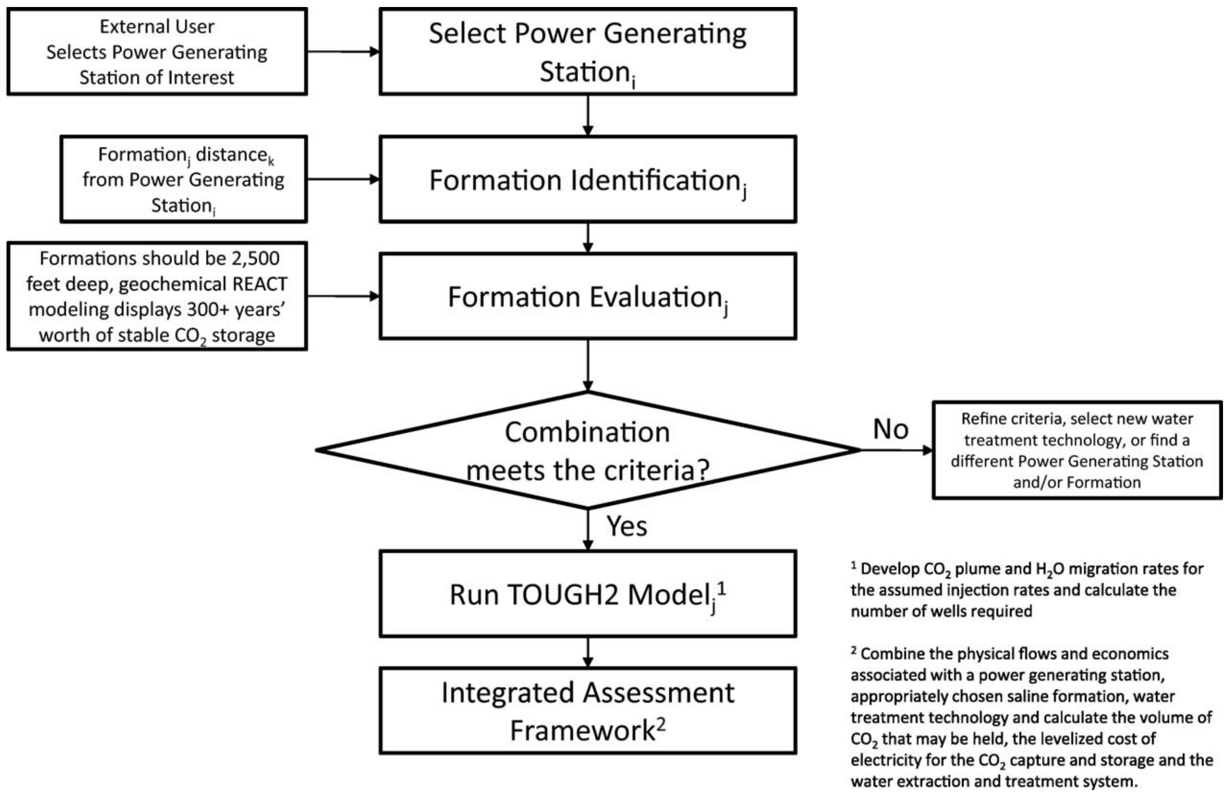

Fig. 2. The decision framework as applied to one representative power plant (i), and several geologic saline water-bearing formations (j).

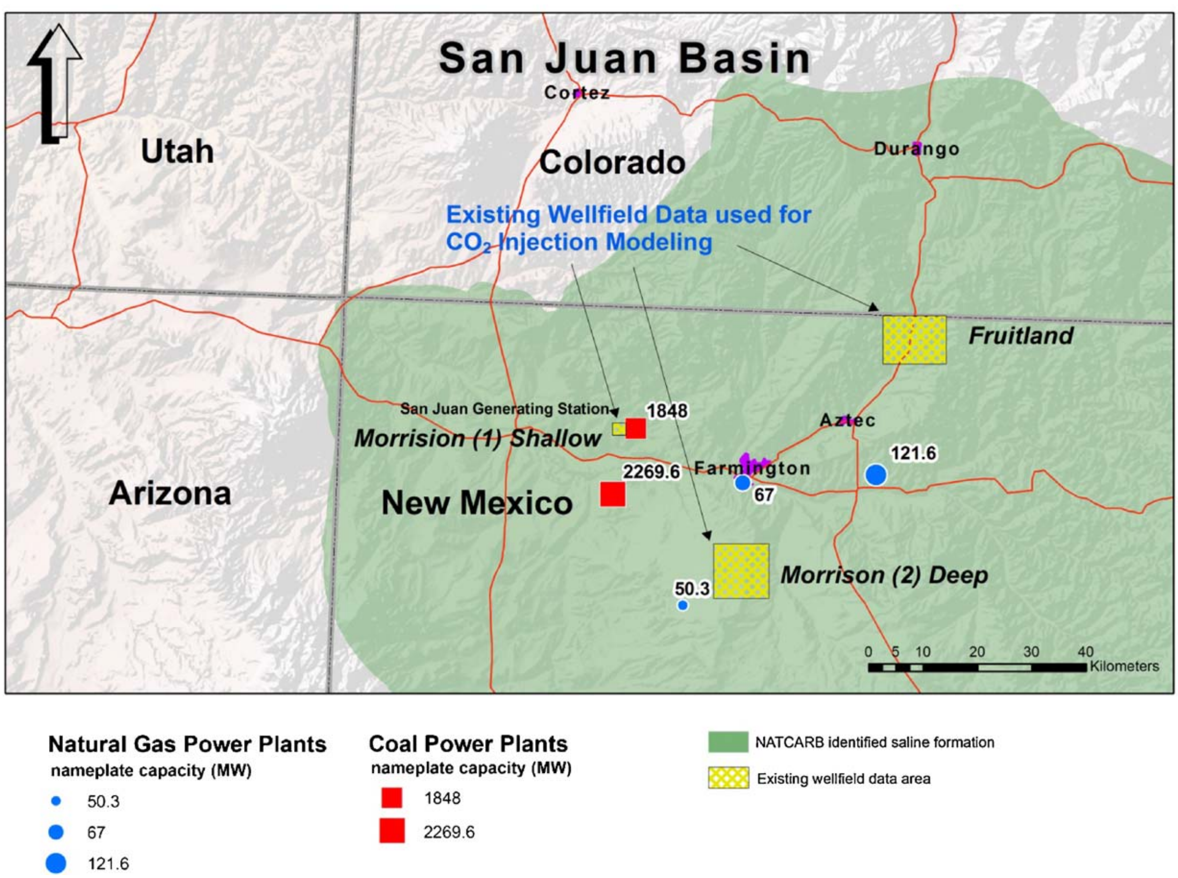

Fig. 3. Four Corners region, San Juan Generating Station (SJGS), and other coal-fired and natural gas power plants, and map view of injection/storage regions in the San Juan Basin, New Mexico, United States.

35,000 ppm due to higher capital costs, larger amounts of energy required, and practical limits to fresh water recovery efficiency for the reverse osmosis systems. Thermal desalination methods could be utilized, but with generally higher costs and lower efficiencies (NRC, 2008; USBR and SNL, 2003). Second, the depth of a host formation into which CO_2 is injected must be at least 2500 ft in order to confine the gas at the requisite pressure and ideally, maintain the majority of the CO_2 within the supercritical phase (i.e., a density of about 600 kg/m^3).

With these criteria in mind, the study builds from the NatCarb database (NatCarb, 2008) and analyzes wells within about 50–80 km (initially) of the target power plant that are both of sufficient depth, and have a record of producing waters with the desired salinity range with additional detail provided in Kobos et al. (2008, 2010). This radius of influence derives from economic and practical considerations of pumping CO_2 between plant and injection site locations.

Based on storage, an initial formation assessment (e.g., Allis et al., 2003; NatCarb, 2008) has determined several suitable formations in the San Juan Basin region nearby the SJGS. These include the Cretaceous Fruitland, Point Lookout, Dakota and Gallup Sandstone in Mancos Formations, members of the Morrison Formation, and the Hermosa Group of the Paradox Formation. Other formations were rejected either because the water is too saline for economical treatment, or being too shallow for injection and storage of supercritical CO_2.

The Hermosa/Paradox Formation was eliminated from the selection of formations due to the fact that it lies below the other formations so that, at least to the east of the SJGS, drilling a well to access this formation would hit all the other formations first. Also, because the formation actually consists of a limestone-shale mix it might be difficult to argue that it may contain a sufficient amount of saline water and/or CO_2 storage capacity. The Gallup, Point Lookout and Dakota sandstone formation waters all have TDS levels less than 10,000 ppm, and so were also eliminated from consideration. The Fruitland sites have TDS levels between the acceptable range of 10,000 and 35,000 ppm TDS, but only one site is beyond 2500 ft deep. Finally, the Morrison Formation has sufficient capacity, a wide regional extent, acceptable depth, and favorable geochemical properties. To assess feasibility of our coupled-use approach, we examine the Fruitland and Morrison Formations as examples.

4.2. Geochemical modeling

Our analysis evaluates whether injecting CO_2 into these representative formations would initiate deleterious chemical changes such that undesirable constituents such as heavy metals may become sufficiently mobilized due to changes in pH and other notable interactive effects. To determine this, in situ water chemistry was obtained for the Fruitland and Morrison Formations. This background geochemical information was then used in investigating several scenarios of geochemical changes following injection of CO_2. Relevant time frames for these scenarios range from approximately 100 years for activities related to current power plant operations out to 350 years.

The reaction path code REACT (Bethke, 1998) was used to assess what chemical changes might occur if CO_2 was injected into various formations. Kobos et al. (2008) contains details on the modeling approach and its application to other sites. Briefly, the REACT models considered mixes of the appropriate formation minerals and brackish (saline) water together with an excess of CO_2. Reaction rates for the minerals were typical values found in the literature (Xu et al., 2003, 2004, 2005, 2007; Pruess et al., 2003; White et al., 2005), and the proportions of different minerals put into the models were based on formation descriptions in the geologic literature. Consideration was given to (1) how the fluid and rock would interact in the absence of CO_2 (the result of which should compare favorably with the actual assemblage of minerals found in a formation that had equilibrated with that brackish water); (2) the interaction of the brackish water and CO_2 in the absence of any rock (essentially a baseline for assessing how the brine chemistry changes when the brackish water–CO_2 mix comes in contact with the rock); (3) the state of the system after 100 years; (4) the state of the system after 350 years; and (5) after the CO_2–rock–brackish water mix had fully equilibrated (presumably many thousands of years into the future). Details of these calculations can be found in Kobos et al., 2008; here we focus only on the salient features of the geochemical modeling results.

The main geochemical considerations relative to using the waters extracted from the Morrison and Fruitland Formations are:

- Water users will (still) need to accommodate levels (parts per million) of both silica and iron, and possibly bisulfide (HS^-).
- In time frames relevant to CO_2 storage, the overall salinity levels of CO_2–charged brackish water will not change much from that characteristic of the indigenous brines. However, levels of minor constituents such as magnesium, calcium, potassium, and sulfate may have changed.
- Clays and other Al–Si containing minerals only react very slowly with the mildly acidic CO_2–charged brackish water. Hence, mineralization of the injected CO_2 is not going to be a quantitatively significant process until many thousands of years have elapsed.
- Precipitation of calcium sulfate (as the mineral phases gypsum or anhydrite) could occur in the short term and possibly impact CO_2 injection activities.

4.3. Reservoir modeling of CO_2 injection into San Juan Basin saline formations

Carbon dioxide injection and storage in two saline formations in the San Juan Basin were assessed by combining information on formation and caprock geometry and properties with reservoir modeling using TOUGH2 (Pruess et al., 1999). Three sites were examined in detail based on the above criteria. These included the initial 'Morrison (1) Shallow' site, located within the Jurassic Morrison Formation (Dam et al., 1990a) about 1.4 km deep and 24 km north and west of Farmington, NM, USA; the 'Morrison (2) Deep' site, located approximately 1.9 km deep and 16 km south of Farmington, NM, USA; and a third site within the Fruitland Formation, a little less than 1 km deep and 24 km east of Farmington, NM, USA (Fig. 3). Simulations of injection of supercritical carbon dioxide were done using the TOUGH2 software (Pruess et al., 1999) with the ECO2N equation of state for CO_2–brine–salt multiphase system (Pruess, 2005). In order to constrain saline formation geometries and flow properties, earth models of both sites were developed using information from the State of New Mexico Oil Conservation Division (OCD) online database (EMNRD, 2008) on petroleum wells in the region, combined with data on hydraulic conductivities from calibrated United States Geological Survey flow models and other recent results obtained from the National Energy Technology Laboratory's Southwest Regional Partnership on Carbon Sequestration.

4.3.1. Geologic framework (earth) models

A first step in the development of a numerical CO_2 storage simulator for the SJGS is to create a geologic framework, or earth model, to represent the relevant rock strata in the subsurface. Using data from the OCD and data from the literature (e.g., Stone and Mizell, 1978), the analysis compiled petroleum well log data for the San Juan Basin sites. Formation boundary locations from well log data are combined in a three-dimensional earth model using C-Tech's MVS^{TM} software. Point data are 'kriged' to create boundary sur-

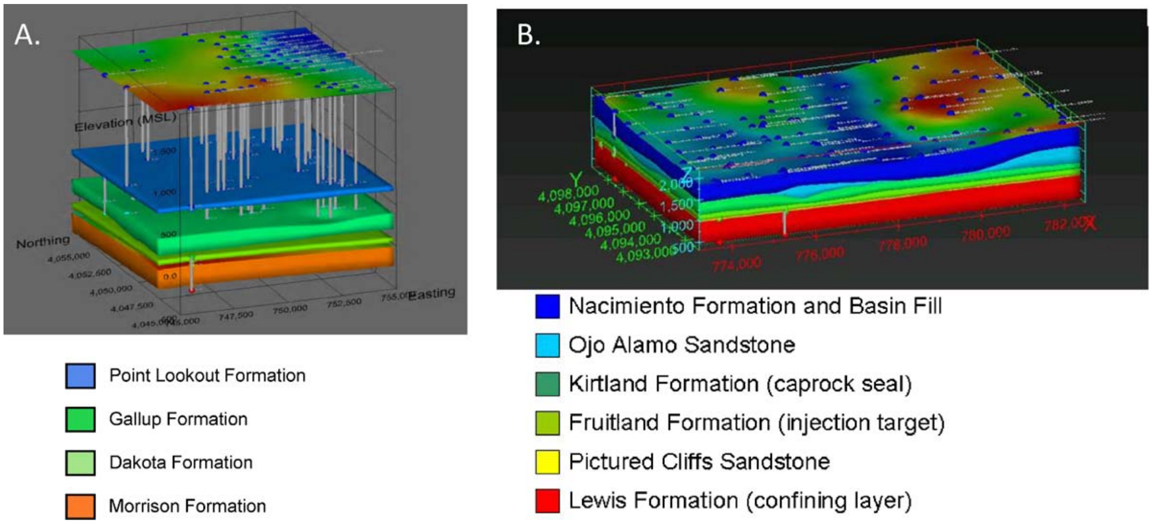

Fig. 4. Earth model for Morrison (2) site (A) and Fruitland site (B), developed using the MVS software (C-Tech) and formation tops found from the NM OCD database (wells shown as vertical pipes in A and surface dots in B). The dominantly clastic sections consist of sandstone formations, which potentially could serve as reservoirs for CO_2 injection, separated by finer grained shales and mudstones, which are proposed as seals or caprocks. (A) Volumes of sandstone bodies determined from well data. (B) The Cretaceous marine formations (Lewis Formation, Pictured Cliffs Sandstone, and Fruitland Formation) are roughly flat lying tabular bodies. The top of the Kirtland Formation (dark green) is part of a regional unconformity, and shows large paleo-topography comparable to a modern river channel in the present day surface topography.

faces which constrain formation geometries. Fig. 4 portrays earth models for the Morrison (2) and Fruitland sites (the shallower Morrison (1) case is similar to the deeper Morrison (2) shown in Fig. 4, in terms of stratigraphy and layer thickness). In all three cases, the layered sequences are discretized into grids for use with the TOUGH2 reservoir simulator. For purposes of the feasibility study presented here, all three cases examine a two-dimensional north–south oriented simulation domain consistent with the regional structural trend of extension fractures in this portion of the San Juan Basin (Lorenz and Cooper, 2003) and thus the trend of highest hydraulic conductivity.

4.3.2. Hydrogeological models

In assessing hydrogeologic properties of the three sites (two Morrison, one Fruitland) for the purposes of modeling injection and storage, hydrostratigraphic units are defined and permeabilities for each were taken from published calibrated groundwater models. We make no additional inferences as to grid-scale heterogeneity (which is largely unknown for the injection lithologies of interest here) as per its influence on plume migration, but follow the example made by groundwater models for the regions in assuming constant properties per lithologic unit. For the Morrison cases the units of Thomas (1989) are used; while for the Fruitland

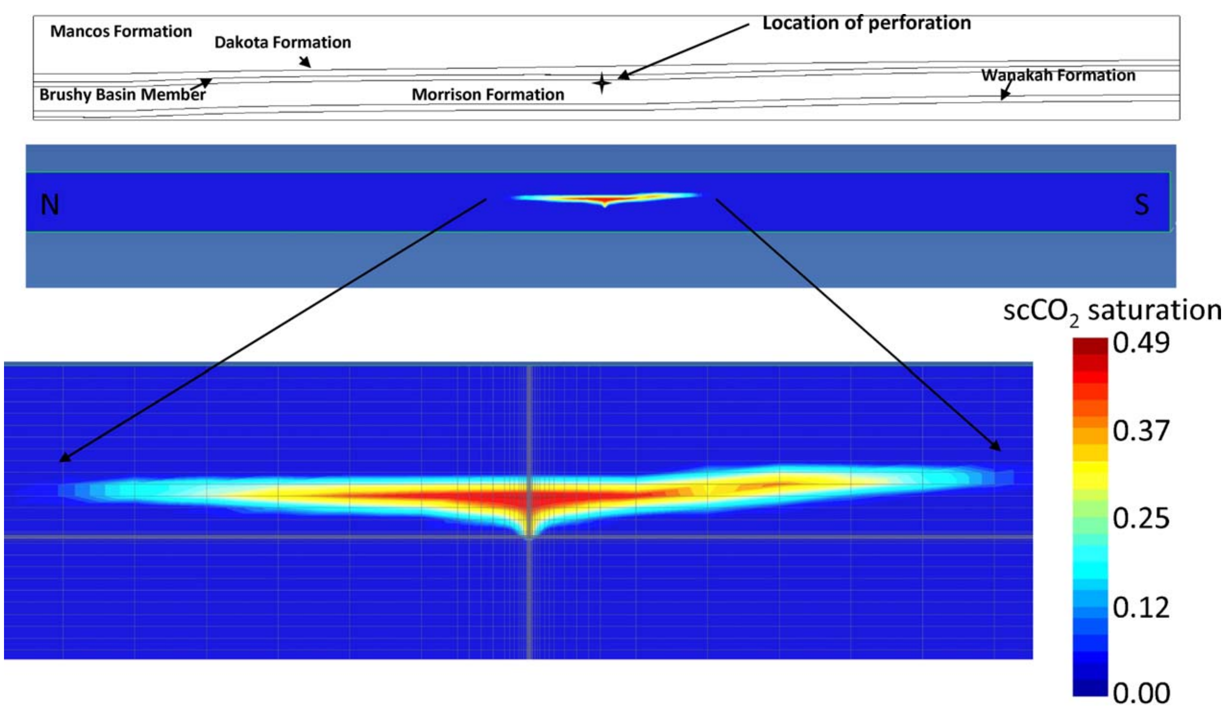

Fig. 5. TOUGH2 simulation showing injection into the Morrison (2) Formation, assuming isotropic hydraulic conductivities. The supercritical CO_2 ($scCO_2$) plume migrates upward and against the Brushy Basin caprock after 30 years of injection. Horizontal axis is 12 km, vertical axis is 1 km.

Table 1
Absolute permeabilities used for TOUGH2 modeling.

Hydro-stratigraphic unit	Permeability (m^2)[a]	
	Horizontal	Vertical
Confining unit[b]	7.5E−16	7.5E−20
Dakota Formation[c]	3.3E−13	2.9E−17
Brushy Basin confining unit[c]	7.5E−15	7.1E−18
Lower Morrison Formation[c]	4.1E−13	2.9E−17
Wanaka confining unit[c,d]	7.5E−15	3.1E−17
Ojo Alamo Formation[e,f]	2.5E−13	5.1E−15
Kirtland confining unit[d,f]	2.9E−18	8.2E−20
Fruitland Formation[g]	5.8E−15	5.8E−17
Pictured Cliffs Formation[h]	2.0E−15	2.0E−17
Lewis Formation confining unit[i]	7.5E−16	7.5E−20

[a] Assumes temperature of 30 °C and brine density of 1100 kg/m^3.
[b] Frenzel (1983).
[c] Thomas (1989).
[d] Kernodle (1996).
[e] Thorn et al. (1990).
[f] Values of K_z from Heath (2010).
[g] Stone et al. (1983).
[h] Dam et al. (1990b).
[i] Values taken to be equivalent to those for Mancos shale.

case the analysis used hydrostratigraphy proposed by Kernodle (1996), Kernodle et al. (1989) and Frenzel and Lyford (1982). These are shown in the right-hand columns of Table 1 for both cases. Permeability values listed in Table 1 and used in the reservoir simulations were determined by the cited authors by calibrating groundwater models against available well and recharge data. Hydrostratigraphic units for the Morrison cases include the lower Jurassic Wanakah confining layer, members of the Jurassic Morrison Formation and injection horizon (Recapture and Westwater Canyon members), the Jurassic Brushy Basin confining unit (upper member of the Morrison Formation), the overlying Cretaceous Dakota Formation, and the Cretaceous lower Mancos confining unit (also known regionally as the Niobrara Group). Units for the Fruitland site (all Cretaceous) include the Lewis Formation confining unit, the Pictured Cliffs Formation, the Fruitland Formation (and injection horizon), the overlying Kirtland Formation confining unit, and the Ojo Alamo Formation. Lithologically, the injection and storage horizons are interbedded sands, muds, and shales, while the confining units are mostly mudstones.

4.3.3. Injection and storage of CO_2

To model CO_2 injection, migration, and phase partitioning with the TOUGH2 reservoir simulator, we require parameters for the multiphase flow properties, porosities, and densities for the hydrogeologic layers, most of which are largely unknown. We used a porosity of 13% and 15% for the Morrison Formation and Fruitland Formation injection horizons based on best estimates from the literature (Dam et al., 1990a; Kernodle et al., 1990); other parameters to describe multiphase flow in clastic sands, mudstones and shales were taken from Pruess (2005). Grids constructed in all cases consist of a coarse horizontal 500 m-spaced grid with a finer grid (progressively down to 1 m spacing) surrounding an injection well centered within the simulation domains. Vertical grid resolution was taken to be a coarse grid of 50–100 m depending on formation thickness and fining at caprock reservoir boundaries and near injection zones to 1 m. Boundary conditions applied to the simulation domain include open lateral boundaries (this was done by including artificially large volumes for model cells adjoining side boundaries), a closed (no-flux) lower boundary, and a constant pressure applied to the upper boundary at a magnitude consistent with a 0.01 MPa/m hydrostatic gradient.

Examples of CO_2 injection and storage are shown in the next three figures. Fig. 5 shows a 2-D example of injection at modest rates of 0.1 kg/s into a 1-m thick (dimension into the page) horizon for the Morrison (2) case as is applicable to injection from a horizontal well. In this case, vertical permeabilities were assumed equal to horizontal permeabilites. This shows the classic 'gravity override' buoyancy driven plume migration up against the Brushy Basin caprock. Fig. 6 shows a case using anisotropic permeabilities; in this case, the large anisotropy yields a more 'pancake' shaped plume. This is likely a more realistic scenario, with large lateral plume migration given the layered nature (i.e., with finer and coarser layers) of these sandstone reservoirs. A small 'mound' of overpressure produced by the injection is evident in Fig. 6. Fig. 7 shows the effect of simultaneous water withdrawal from a well positioned 6 km away from the injection well on the induced overpressure. Even at this great distance, overpressure can be mitigated by water withdrawal and treatment for beneficial use prior to the arrival of the CO_2 plume at the withdrawal well.

4.3.4. Plume migration and mass conservation

The spatio-temporal modeling of CO_2 injection in the previous examples can be used to bound the extent of plume migration and to calculate the fate of CO_2 on time scales relevant to power plant operation. Plume migration distances, correlating to breakthrough times in water production wells as in Fig. 7, can be determined from sets of numerical experiments discussed above by varying injection rates and measuring plume extent with time. To do so, the analysis uses pseudo-3-D model grids with 2-D radial extent, to model the effect of 3-D migration. As an example, Fig. 8 shows results of plume migration distances as a function of time (up to 100 years of migration) for the Morrison (2) case. At small injection rates, distances increase roughly linearly with time, but as injection rates increase, plumes increase approximately with square root of time in accord with analytical models (i.e., Bickle et al., 2007). A departure from the analytical models is evident from our simulation results due to anisotropy, dissolution of supercritical CO_2 in surrounding brine (and downward migration of the brine solution due to increased density), and gas/brine migration into surrounding formations with contrasting geohydrologic properties. We find that the radius (L) of an effective pancake-shaped CO_2 plume increases as a power law

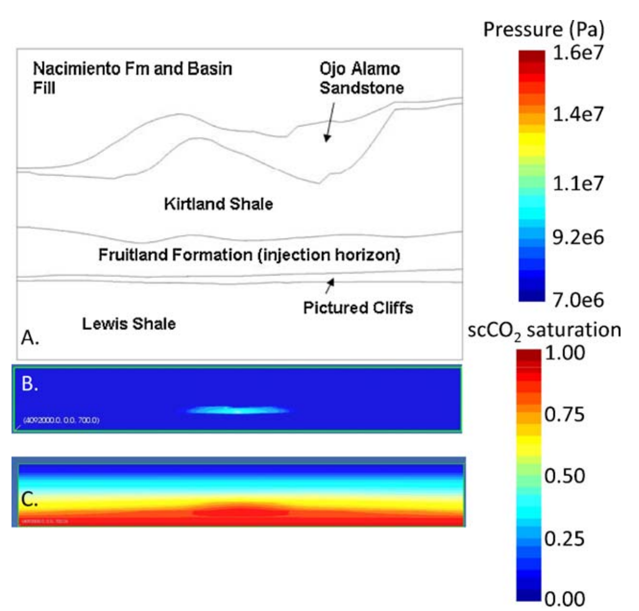

Fig. 6. TOUGH2 model of injection within the Fruitland Formation assuming anisotropic permeabilities. (A) Cross section (10× vertical exaggeration) showing the Fruitland Formation injection horizon and overlying Kirtland Formation caprock. (B) Plume spreads laterally and up against Kirtland Formation caprock. (C) Small amount of overpressure attending injection after 30 years.

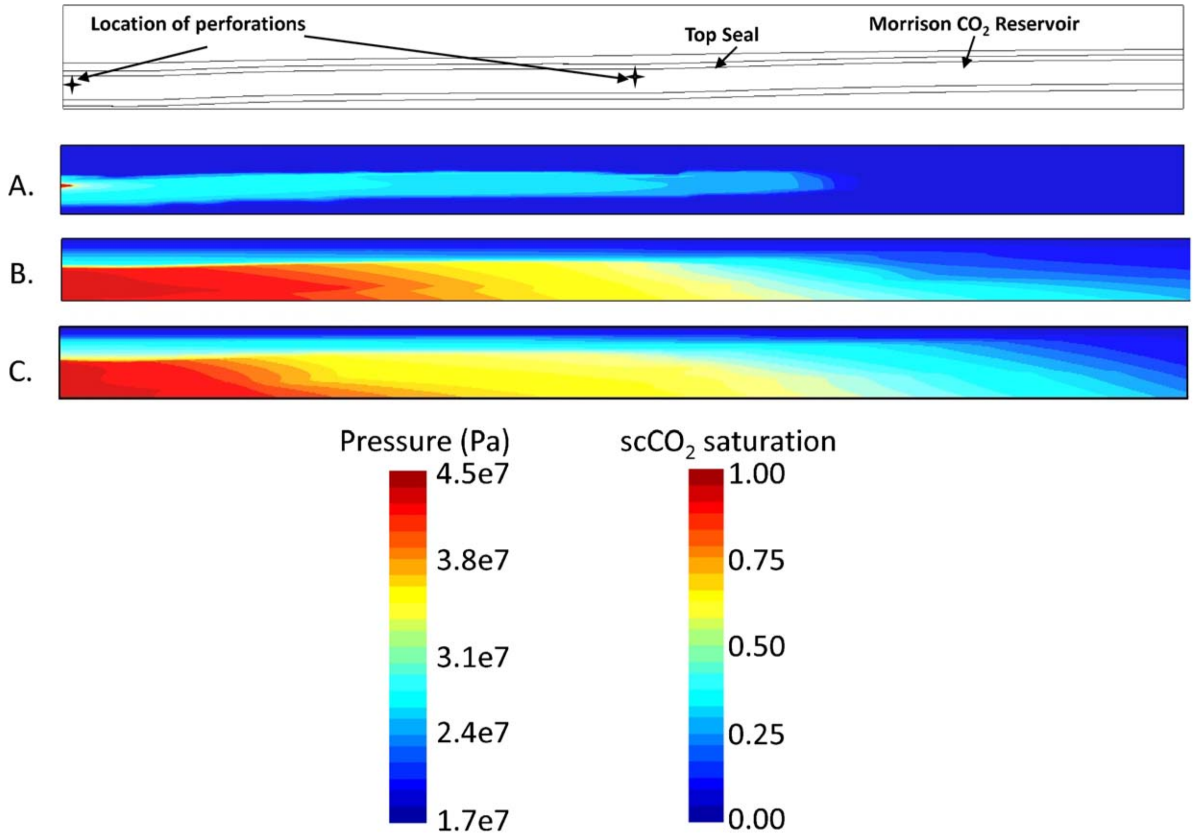

Fig. 7. Example of TOUGH2 simulations in Morrison (2) example. (A) CO_2 plume after 30 years of injection. (B) Pressure profile after 30 years (corresponds to A) with no water withdrawal. (C) Pressure after equi-volume withdrawal of water from the formation, at the 'well' perforation zone in the middle of the simulation domain.

function of both injection rate (I) and time (t), such that

$$L = 16.35 I^{0.49} t^{0.40} \quad (1)$$

for the Morrison cases and

$$L = 0.019 I^{0.34} t^{0.44} \quad (2)$$

for the Fruitland site. Here L is in km, I in tonnes/day, and time in years (R^2 from linear regression analysis is 0.98 for both equations). The differences between the two models are attributable to differences in formation geometries, hydrogeologic properties, and those of surrounding lithologies including caprock. These expressions are used in the integrated assessment model developed for this study.

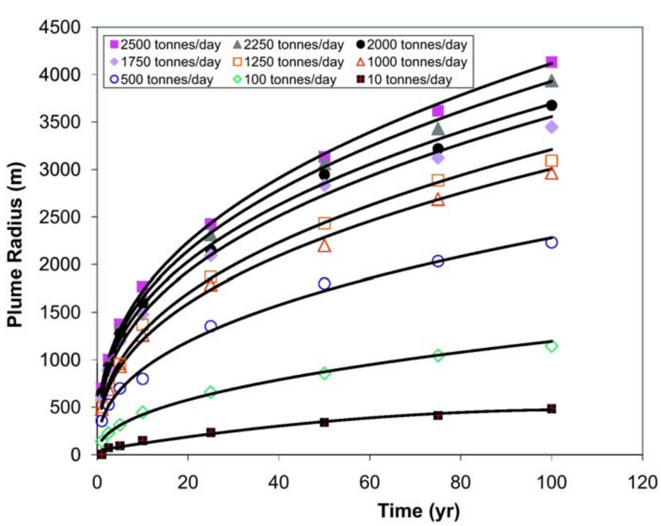

Fig. 8. Plume migration distance for the Morrison (2) example, plotted as a function of time and injection rate. Solid lines are fits to power-law expressions given in the text.

4.4. Extracted water treatment

Power plants may have both the demand for additional cooling water resources, and access to the potential financial means required to treat brackish water from geological saline formations. Population growth, drought, power generating technologies, carbon dioxide capture systems and water desalination technologies may all have very region-specific attributes. The confluence of these factors will determine the relative water stress due to water supply and demand imbalances (Tidwell et al., 2009).

Carbon dioxide capture technologies and their associated energy and water stream requirements pose substantial challenges for wide-spread adoption of these technologies (DOE/NETL, 2007). This analysis assumes that pulverized coal subcritical power plants use an amine absorber for the CO_2 capture system which, under the current technology's readiness level, has a substantial water demand. Additionally, it is important to account for water chemistry in the design of the plant systems using this technology. There are site-specific limits on water treatment design based on the actual water quality, metallurgy of the piping system, materials of construction of the cooling tower itself, and regulations on the waste streams (liquid and solid). Cooling towers that utilize surface waters and/or low TDS well waters can easily meet many of these requirements and operate efficiently. However, many alternative sources of water (brackish from saline water-bearing formations, produced water from hydrocarbon extraction operations, waste water from municipalities and other sources) will most likely have elevated levels of chloride and other problematic constituents such

Table 2
Summary of predicted HERO™ product water chemistry.

	Fruitland		Morrison (1)		Morrison (2)	
(ppm)	Initial	Product	Initial	Product	Initial	Product
Na	4100	74	1500	28	5400	99
Ca	44	n/a	310	n/a	290	n/a
Mg	27	n/a	49	n/a	34	n/a
HCO_3	8000	6.0	270	0.20	880	0.70
Cl	1500	45	58	1.8	2500	78
SO_4	5.6	0.09	3800	64	7900	130
TDS	14,000	260	6000	110	17,000	330

as organic constituents, calcium, and silica. Elevated levels of chloride can lead to corrosion; elevated calcium, magnesium, and/or silica can lead to scale formation and increased energy consumption by the condensers. Higher TDS waters would require different and likely more expensive operational and maintenance costs, but they offer a potential supplemental source of cooling waters.

The water treatment for cooling water assumptions and calculations used herein are based on Zammit and DiFilippo (2004), the USBR (2003) desalination cost estimations, and insight from several additional studies (Klausner et al., 2004, 2005; McCabe et al., 1993; Miller, 2003). Zammit and DiFilippo (2004) present reverse osmosis treatment effectiveness for conventional reverse osmosis (CRO), High Efficiency Reverse Osmosis (HERO™), and other techniques to desalinate a brackish water with a TDS of approximately 12,000 ppm. The pre-treatment and HERO™ removal efficiencies for each element were calculated and used to predict the final product water for each of the waters evaluated in this study. While the HERO™ system was the technology selected for this analysis, others such as thermal desalination may be viable for higher ranges of salinity. This paper provides the methodology by which the technologies could be evaluated. Table 2 summarizes the initial feed water and the predicted product water chemistry.

Several desalination options were studied using a spreadsheet analysis to then become a central component of the integrated assessment. These options all utilized HERO™ (high efficiency reverse osmosis) for desalination and varied in the mode of waste water disposal. Although a HERO™ system may not be required (the waters may not have the high fouling constituents present), the cost estimations should be conservative. For additional clarity, Fig. 9 presents a schematic for the water treatment options used within the integrated assessment for the representative SJGS example.

Future work may compare other increased efficiency reverse osmosis systems, as well as other means of desalination. The water treatment cost estimate for a single formation (Morrison (2)) is summarized in Table 3. These options and assumptions are used in the integrated assessment model's calculations. The assumptions included in this model for HERO™ and brine concentrator capital and operational costs are based on the analysis developed in Zammit and DiFilippo (2004), which was based on specific water chemistry information. Therefore, analyzing formations with different water chemistries, and specifically salinity levels, will likely affect the capital and operational costs.

An analysis was also developed for the additional saline formation cases discussed in Section 4, and it is worth comparing the costs for each waste disposal option. These are summarized in Table 4, and largely vary due to differences in the base cost of electricity, cost to capture CO_2, water chemistry, formation depth and distance from the power plant. Thus the Morrison (2) example bears the largest treatment costs. The least costly option is to store CO_2 and extract water from the Morrison (1) example.

For additional comparison purposes, a recent study by MIT (2009) cites the base and retrofit costs of an old pulverized coal power generating station (such as the one presented here) as approximately 3.68 cents/kWh for the base cost and, 9.79–10.24 cents/kWh (2008 $US) for the base cost plus 90% CO_2 capture for various technologies. The National Energy Technology Laboratory also cites similar costs for a puliverized coal plant with a base cost of approximately 3.38 and with 90% capture of CO_2 of 7.79 cents/kWh (2007 $US) (NETL, 2009). The base and CO_2 capture costs presented in these two studies are in line with those underlying the results in Table 4 given the site-specific variables and uncertainties of power generating stations that will affect the cost to capture CO_2 (e.g., coal type, Flue Gas Desulfurization system, physical layout of the power station).

4.5. Integrated assessment model

4.5.1. Model design

The goal of the integrated assessment model is to illustrate engineering and economic constraints associated with a suite of technologies applied to an existing power plant for both CO_2 storage and beneficial use of treated water from a saline formation. The integrated assessment model builds on the geotechnical modeling and water treatment analyses developed in Sections 4.1 through 4.4.

The integrated assessment model incorporates the stocks and flows associated with the power plant's metrics including electricity production, flow of CO_2, water resource needs, and it also identifies costs associated with the system's components. This model allows interested parties to perform 'what if' scenario analyses in real time for the interested scenario development user. For example, the model can address questions such as, 'What if the level of CO_2 capture increases from 50% to 90%? What will the electricity costs look like due to this change?' Similar scenario questions can be developed for different power plant configurations, geological formations used for CO_2 storage, and brackish water treatment technologies.

The analysis applies the integrated assessment model to the SJGS/Morrison Formation example. The analysis evaluates CO_2 storage into a saline formation along with a water extraction and treatment system to exploit the potential extracted brackish water to help meet a portion of the power plant's cooling needs.

4.5.2. Base case parameters and costs

The key metrics of interest provided by the integrated assessment model are the input variables for the SJGS, the representative formation characteristics (e.g., size, depth), as well as potential longevity of the formation to store CO_2 and the amount of water extracted from the formation for beneficial use. Engineering variables in the integrated assessment model include the amount of CO_2 generated by the plant per year, the percent of CO_2 captured, pipe flow limitations, and the distance from the plant to injection wells. Economic variables include the capital and variable costs per well, discount rate, pipeline lifetime, and operations and maintenance costs. The costs associated with the CO_2 capture system's components are based on work developed by NETL (2006/2007). The SJGS generates ~13 M tonne/yr of CO_2 with an estimated water demand of 6.90 ft^3 per boiler (EPA, 2007). The analysis scenarios assume there can be a distance of 6–100 km from the injection well to the extraction well.

Morrison Formation storage volume and lifetime is linked to the CO_2 plume extent, and its proximity to water extraction wells. The plume radius is dependent on time and injection rate as per Eq. (1), and the injection volume is assumed to be the volume of the cylinder given by the formation height and plume radius. The lifetime of storage is determined by the distance from the injection well to the first extraction well. When the plume radius equals this distance, storage is assumed to stop. A radius of 10 km yields a storage volume of 1069 M tonnes, and a sink longevity of 162 years.

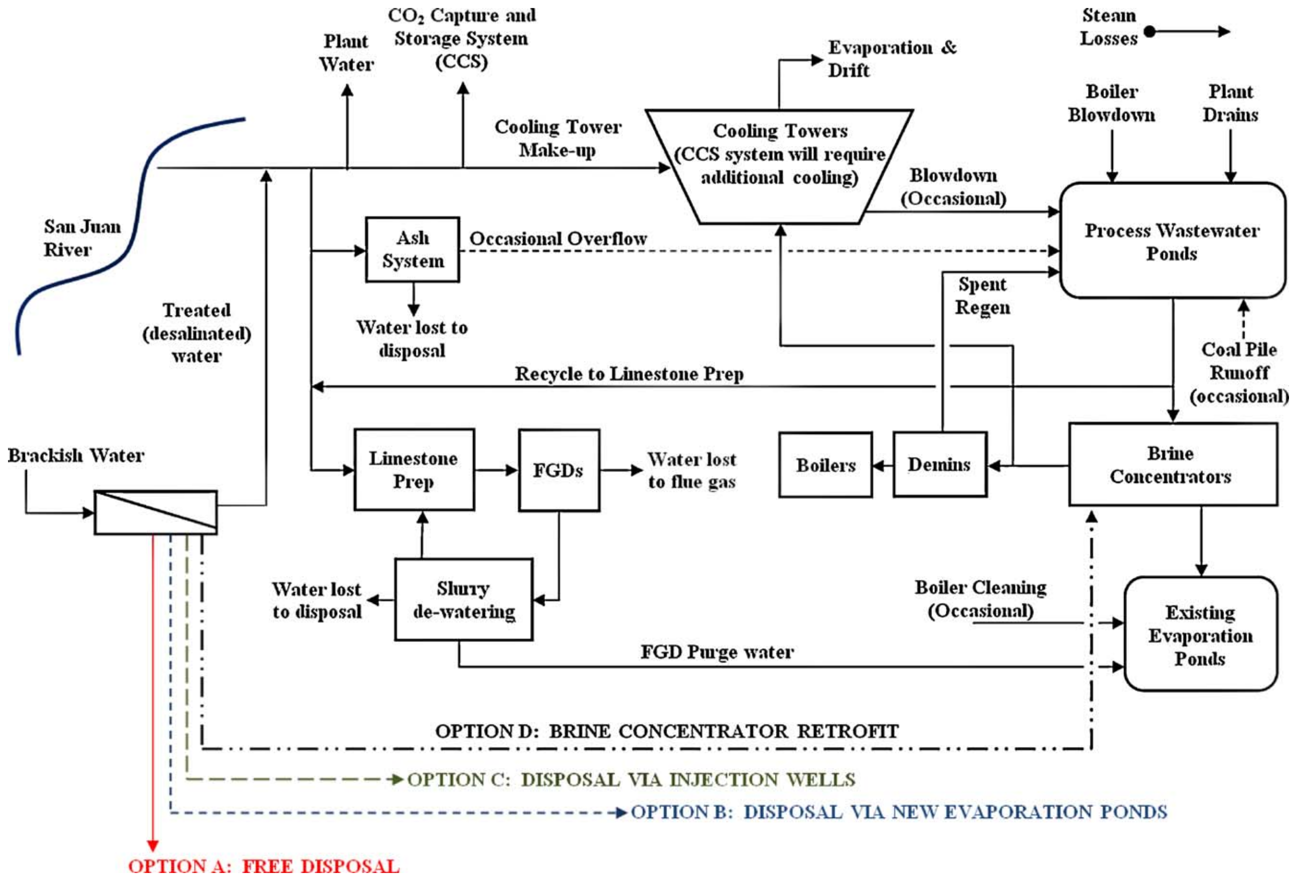

Fig. 9. Schematic of the water treatment options within the representative pulverized coal power generating station. Adapted from Zammit and DiFilippo (2004).

Capturing and storing CO_2 within a saline bearing formation presents an opportunity to use the potentially displaced saline waters. Using the CO_2 density displacement information outlined in Clark (1966) and Benthan and Kirby (2005), this modeling framework assumes under the base case scenario that (assuming hydrostatic pressure), every gram of CO_2 injected underground displaces approximately 1.52 cm^3 of saline water. While pressures involved with this base case lie within the supercritical range of the CO_2 density–vapor curve analysis, the integrated assessment model allows for alternative potential densities of CO_2 based on attributes of the formation under consideration. The initial depth for the Morrison (1) Formation is 4725 ft. This translates into an approximation where 400 gallons (~1500 L) of saline water may be displaced for every tonne of CO_2 stored under these representative conditions, and a total of 1.4 million gallons per day (MGD) of potential treated water. This represents 6% of the SJGS annual plant demand for water, and means that approximately 162 years of water for the SJGS resides in the Morrison.

Together with the base costs for water treatment given in Table 3 of $9.14 per 1000 gallons of treated water, and the base cost for SJGS electricity of 5 cents/kWh, the total electricity costs for the Morrison (2) base case storage and HERO™ water treatment scenario increases the cost to approximately 9–12 cents/kWh. Additional parameters and costs for the projected base case are summarized in Tables 4 and 5.

5. Discussion

5.1. Base case energy, water and net CO_2 emissions

Table 6 compares initial energy, water requirements, net CO_2 emissions, and costs associated for the base SJGS power plant, base

Table 3
Summary of water treatment costs (2009 $US).

	Options A[a]	Option B[b]	Option C[c]	Option D[d]
Annual O&M	$2,458,798	$2,702,455	$2,524,172	$3,111,992
Electricity Cost	$2.72/1000 gallons	$2.72/1000 gallons	$2.72/1000 gallons	$3.87/1000 gallons
Total capital cost	$16,212,165	$32,455,934	$20,360,824	$19,594,244
$/1000 gallons[e]	$7.34/1000 gallons	$10.35/1000 gallons	$8.11 $/1000 gallons	$9.14/1000 gallons

[a] Desalination and gathering – equipment only (Brackish Water Reverse Osmosis (BWRO)); no concentrate disposal.
[b] Desalination and gathering – equipment only (BWRO); 59.5 acre evaporation ponds for concentrate disposal.
[c] Desalination and gathering – equipment only (BWRO); 3000 ft injection pipeline, surface piping and well for concentrate disposal.
[d] Desalination and gathering – equipment – HERO™ + Brine Concentrator (BC) retrofit. Zammit and DiFilippo (2004), based on higher TDS.
[e] Assumptions: pump efficiency, 0.80; motor efficiency, 0.85; reverse osmosis efficiency, 0.75; capacity factor for the water treatment system, 0.85; years of payments on the equipment, 20; interest rate, 5%; base cost of electricity, 5 ¢/kWh; 2009 $US (Zammit and DiFilippo, 2004; OMB, 2009). These water treatment systems were designed based on the size of the plant chosen for a retrofit case and the Morrison (2) 'Deep' scenario.

Table 4
Water treatment costs for three saline formation examples, by water treatment option.

Formation	Option A BWRO ($/1000 gallons, (¢/kWh)[a,b,c,d])	Option B BWRO-evaporation ponds	Option C BWRO-injection well	Option D HERO™ + BC retrofit
Morrison (1)	6.26 (8.91)[a]	9.28 (8.92)	7.04 (8.91)	8.06 (8.92)
	6.26 (10.08)[b]	9.28 (10.09)	7.04 (10.08)	8.06 (10.08)
	6.22(12.41)[c]	9.28 (12.43)	6.94(12.42)	7.97 (12.42)
	7.38 (11.92)[d]	10.40 (11.93)	8.16 (11.92)	9.88 (11.93)
Morrison (2)	7.34 (8.92)	10.35 (8.93)	8.11 (8.92)	9.14 (8.92)
	7.34 (10.08)	10.35 (10.09)	8.11 (10.08)	9.14 (10.09)
	7.30 (12.42)	10.35 (12.43)	8.02 (12.42)	9.05 (12.43)
	8.97 (11.92)	11.98 (11.93)	9.75 (11.93)	11.46 (11.93)
Fruitland	6.48 (8.91)	9.50 (8.92)	7.26 (8.91)	8.28 (8.92)
	6.48 (10.08)	9.50 (10.09)	7.26 (10.08)	8.28 (10.08)
	6.38 (12.41)	9.43 (12.43)	7.10 (12.42)	8.13 (12.42)
	7.40 (11.92)	10.42 (11.93)	8.18 (11.92)	9.90 (11.93)

Assumptions: 50% CO_2 capture at ~$72/tonne CO_2, 2009 $US.
[a] 5 ¢/kWh levelized cost of electricity (Zammit and DiFilippo, 2004; OMB, 2009).
[b] 5 ¢/kWh, 30% increase in CO_2 capture cost above base case.
[c] 5 ¢/kWh, 90% CO_2 capture.
[d] 8 ¢/kWh base plant levelized cost of electricity (NETL, 2009), where: total system ¢/kWh = base plant levelized cost of electricity ($LCOE_{base\ plant}$) + ¢/kWh for CO_2 capture and storage ($CCS_{¢/kwh}$) + ¢/kWh for water treatment (WT); ($CCS_{¢/kwh,\ 50\%\ capture} = LCOE_{base\ plant} * 1.73$); with 50% and 90% capture the assumed incremental increase in LCOE is 73% and 138%, respectively (NETL, 2006/2007; NETL, 2009); base case example for WT: ($9.14/1000 gallons) × (1,400,000 gallons/day)/((1,848,000 kW × 0.7736 capacity factor × 24 h/day)) = 0.04 ¢/kWh for water treatment; Kobos et al. (2010) contains additional detail on the modeling assumptions.)

Table 5
Projected base case CO_2 capture, storage, and water treatment costs[a].

Input variable	Base case value	Result parameter	Result value
Power plant emissions (CO_2)	13,165,665 tonne/yr	CO_2 sink longevity	162 years
% CO_2 captured	50%	Potential treated water	1.4 MGD
Formation depth	6359 ft	% of annual plant demand met	6%
Formation size	1069 mmt	Years' worth of H_2O in formation for plant	162 years
Power plant water demand	6.90 ft^3/s/boiler	Plume migration distance	3164 m (40 years)
		Electricity cost	5 ¢/kWh
		Water treatment cost	$9.14/1000 gallons H_2O
		Total electricity cost	8.92 ¢/kWh

[a] San Juan Generating Station tonnes CO_2/yr, 50% capture, Morrison (2) deep formation, 8 CO_2 storage wells, one H_2O recovery well, HERO™ water treatment system, 2009 $US, plume migration according to $L = 16.35\ I^{0.49}\ t^{0.40}$ where L is the plume radius (km), I is injection rate (tonnes/day) and t is time in years.

Table 6
Base case energy, water and net CO_2 emissions[a].

Parameter	Energy (MW)	H_2O requirement (MGD)	New, treated H_2O (MGD)	Net CO_2 (tonne/yr)	Economics (¢/kWh)[a]
Base power plant	1848	17.84	n/a	13,165,665	5
Base + CO_2 capture and storage and wells (CCS)	2209	24.54	n/a	9,152,267	8.88
Base + CCS + water treatment	2210	24.66	1.4	9,164,202	8.92

[a] *Assumptions*: CO_2 emissions, 13,165,665 tonnes/yr (EPA, 2007); capture of CO_2 from the San Juan Generating Station, 50%; capacity factor, 77% (EPA, 2007); CO_2 well/pipe flows, 104 tonnes/h (Ogden, 2002); distance of power plant to CO_2 storage well, 30 km; capital cost per well, $1 million/well; variable cost per well, 1250 $/m; discount rate, 10%; pipeline life, 30 years; O&M, 0.04; 2009 $US; saline formation size, 1069 mmt (calculated, TOUGH2); representative depth, 6359 ft (calculated, TOUGH2).

SJGS plus CCS, and base SJGS plus CCS plus extracted water treatment and beneficial use as cooling water. Adding CCS will increase energy needs by about 20%, along with an increase in water needs by about 43%. This accomplishes a net CO_2 reduction from an initial 13 M tonnes/yr to about 9 M tonnes/yr with costs increasing from 5 cents/kWh to approximately 9 cents/kWh. Adding water treatment to this base scenario does not change energy demand substantially, marginally increases the net CO_2 emissions from the CCS case and increases costs by less than 1 cent/kWh. To summarize, retrofitting an existing plant like the SJGS may increase the energy penalty by approximately 360 megawatts (MW), or a 20% energy penalty under the initial assumptions. Additionally, this will decrease the plant's overall CO_2 emissions profile by 43% (this includes the 50% capture, plus the associated required parasitic power plant's emissions for the CCS system).

5.2. What about CO_2 capture?

Probably the largest uncertainty in the integrated assessment's analysis is the amount of CO_2 that is able to be captured, and the resulting influence on this coupled-use system's economics. The trends plotted in Fig. 10 show that as the percent of CO_2 captured increases, the potential to meet a portion of the power plant's water needs also increases. Similarly, the percent of annual water demands met for the representative power plant may also increase as volumes of CO_2 stored in saline formations increase. Interestingly, there is only a slight decrease in water treatment costs (in $/1000 gallons of water treated). Increasing the percent of CO_2 captured from 50% to 90% leads to an increase in total electricity costs from approximately 9–12 cents/kWh.

It is important to examine the influence of the percent CO_2 capture amount on the number of CO_2 injection wells as it relates to performance and costs. During preliminary runs of the TOUGH2 reservoir modeling of the Morrison Formation, accepting CO_2 assumes a representative one well scenario. The analysis assumes each well can inject up to 2500 tonnes of CO_2 per day. This represents approximately 7% of the annual CO_2 emissions profile for the SJGS. To capture and store 50% of the total annual CO_2 emissions, approximately eight wells may be required. Thus, implementing this type of system with one initial CO_2 injection well, the potential

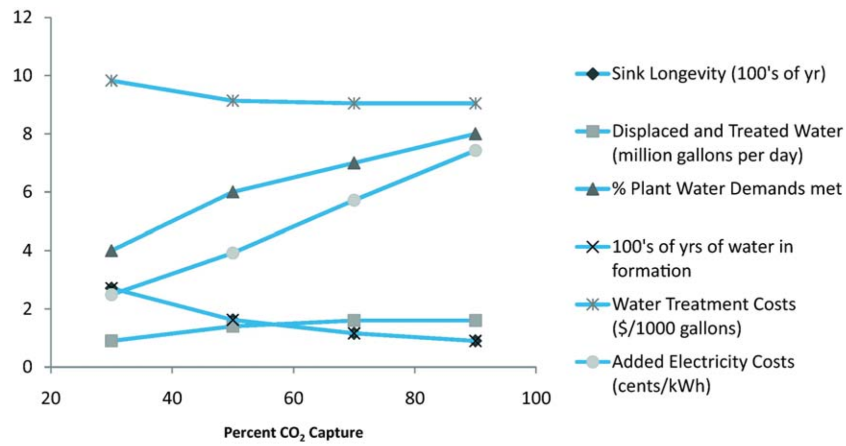

Fig. 10. Impact of changing the percentage of CO_2 captured on system performance and costs. The added electricity costs are the levelized electricity costs in cents/kWh assuming CO_2 capture, pipeline, CO_2 injection wells, water extraction wells, and water treatment costs.

displaced water would meet approximately 1% of the plant's annual water demands when accounting for storing 6% of the plant's total CO_2. As a result, the costs, flow rates and annual CO_2 capacity and water supply could change dramatically depending on the geosystem characteristics, the engineering of the CO_2 capture and storage system, and regulatory constraints associated with using a saline formation resource for these purposes.

5.3. Future work

The analytical team responsible for the work presented here continues to expand the modeling framework to include additional U.S. formations with the aim of offering a multi-formation assessment tool. The analysis is developing and expanding the scale and scope of the user model's input, and expanding the framework presented here into a national-scale assessment. With this information, users will be able to draw from existing saline formation databases such as NatCarb (coordinated by NETL), power plant databases such as eGRID (developed by the EPA), and build from geochemical and geomechanical studies of CO_2 storage and develop additional custom, site specific scenarios. This will lay the groundwork as a first order assessment for potential pilot plant-scale studies and assessing the scale-up potential for these combined technologies in the face of water stress throughout the U.S.

6. Conclusions

An integrated assessment model was developed to quantify the potential economic feasibility for combined water extraction, treatment, and beneficial use with CO_2 storage in the southwestern United States. This includes examining salinity levels of regional saline formations, evaluating water usage for select power plant profiles, and determining cost and systems management requirements. These efforts all contribute to a decision support analysis for potential future CO_2 storage and extracted water use at the power plant level. Geochemical modeling of CO_2 injection shows that little CO_2 is stored in mineral form for engineering time scales up to centuries. Selective carbon dioxide injection does not modify water chemistry to the point of deleteriously affecting extracted water treatment options. Reservoir modeling of CO_2 injection and migration in target saline formations suggests plume migration can be quantified by simple power-law expressions for use in the systems modeling, and shows how water extraction can be used to mitigate injection-induced overpressures. From amongst available water treatment options, the high efficiency reverse osmosis (HERO™) system shows promise for economical desalination of the volumes of recovered water, with pore water chemistries characteristic of deep saline formations in the southwestern United States. For the base case using results from geochemical, reservoir engineering, and water treatment analyses, approximately 6% of power plant water needs can be met while capturing approximately 50% of CO_2 emissions, and increasing levelized electricity costs by a factor of approximately 2. This would suggest that a coupled use system similar to the one suggested here could be technically feasible for power plants similar to the SJGS, if the increased costs are viewed as economically acceptable to the regions served by the power plant.

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