

**NATIONAL ENERGY TECHNOLOGY LABORATORY**



# **Study of the Use of Deep Saline Formations for Combined Thermoelectric Power Plant Water Needs and Carbon Sequestration at a Regional-Scale: Phase I Report.**

June, 2008

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**DOE/NETL-FWP 07-013812**

**June 2008**

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# **SANDIA REPORT**

SAND2008-4037  
Printed June 2008

## **Study of the Use of Deep Saline Formations for Combined Thermoelectric Power Plant Water Needs and Carbon Sequestration at a Regional-Scale: Phase I Report.**

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## **ACKNOWLEDGEMENTS**

Sandia National Laboratories and the authors would like to thank the National Energy Technology Laboratory, and Andrea McNemar in particular, for leading the research in the areas of Energy-Water Program Management and Research. Thanks also go to Mike Hightower and Tom Feeley for their guidance during the initial phases of this project. This report contains format updates as of March 2010.

## **ABSTRACT**

This study assesses a coal-based power plant with carbon sequestration into a deep saline formation combined with a water treatment arrangement of water from the formation to supplement the power plant's cooling requirements. A methodological framework was developed to down select a potential geological formation (the Morrison) near the San Juan Generating Station in New Mexico. Additionally, the framework assesses a suite of water treatment technologies to treat the deep saline formation water to use in the generating station's cooling systems. The framework was further developed into a dynamic simulation model to develop scenarios regarding varying levels of carbon dioxide (CO<sub>2</sub>) sequestration from the power plant, water recovery rates from the formation, and variable costs associated with the whole system's components. The initial findings suggest that many hundreds of years' worth of CO<sub>2</sub> storage resource as well as several hundred years worth of saline water supply may exist for the San Juan Generating Station to Morrison formation paired analysis. Phase II will look to address several key model parameters that may substantially alter these initial findings such as injection rates, plume migration rates, and system economics.

# INTRODUCTION

Concerns over expanding power demands across the country in regions with increasingly restrictive water regulations and environmental considerations may affect the wide-scale adoption of carbon dioxide (CO<sub>2</sub>) management technologies for the power sector. Injecting CO<sub>2</sub> into a deep saline formation, for example, may provide a large storage opportunity for CO<sub>2</sub>, yet could potentially pressurize the formation and require the formation pressure to be relieved by pumping out some of the water. This water might then be treated and made available for use in a power plant.

Several geotechnical questions must be considered when assessing the feasibility of this approach. One is whether the CO<sub>2</sub> will change the water chemistry of the water significantly and affect the economic viability of water treatment options. A second is how the operation of the sequestration system can be conducted to prevent formation damage and CO<sub>2</sub> leakage. A basic understanding of the general operational needs and infrastructure layout is needed to determine the technical and economic feasibility of this opportunity.

Several water treatment and desalination issues must also be addressed. One is the quality of the water from the formation. The second is how waste heat from a thermoelectric power plant might best be used in different desalination processes to reduce water treatment costs. Another is determining the optimum water quality needed for different plant water use options and the most efficient use of the saline water. The final issue is to understand the quality of the treatment concentrate and possible options and costs for management and disposal. Each of these issues must be addressed to assess their impact on the relative cost-effectiveness of saline water utilization in thermoelectric power plants.

Finally, an assessment of the regional applicability of this approach is needed. Many companies considering the use of deep saline formations for sequestration and supplemental water use will probably consider development of plants in regions with large saline resources, coal reserves, and access to electric transmission. While many areas of the country have some of these resources, there may be a trend to potentially locate new power plants in regions with a full suite of these resources to help integrate them into these existing systems. Therefore while it might be feasible to use saline formations in a region with demand for power plants, there is a need to be able to assess the ability of saline formations in a region or area to support multiple power plants, or to use multiple formations to use multiple power plants. This will require the ability to assess the interaction of the different sequestration and water withdrawal options on different deep saline formations, the impact on water and sequestration issues, and on how closely power plants can be sited. This will require a system level evaluation of the different options and an assessment of ways to arrange regional energy development options that are low cost, enhance CO<sub>2</sub> sequestration, and minimize fresh water use by substituting the use of treated saline water. The regional assessment model was largely developed by building from the full team's geochemical and water treatment analyses.

The overall report develops from these three central components; geochemistry, water treatment and the assessment modeling. As such, the references for each sub-analysis are located in their respective chapter. The central authors for the geochemistry, water treatment and assessment

modeling chapters include Jim Krumhansl, Malynda Aragon, and Peter Kobos, respectively. Summary insights and follow-on recommendations are given at the end of this Phase I report as a prelude to future project work.

## ***Roles of the Collaborative Project Between Sandia National Laboratories and the National Energy Technology Laboratory***

A collaborative Memorandum of Understanding (MOU) established between the National Energy Technology Laboratory and Sandia National Laboratories establishes a relationship that acknowledges the intimate link between energy and water and the challenges water availability poses for maintaining future energy supply security and reliability and the opportunities for collaboration between National Energy Technology Laboratory (NETL) and Sandia National Laboratories (Sandia) in addressing these challenges. The purpose of the strategic agreement between NETL and Sandia is to help advance the research, development, demonstration, and ultimately the commercial deployment of technologies, concepts and systems that can reduce fresh water demands and use in fossil energy production and generation. NETL and Sandia mutually share the goal of providing the science and technology and supporting management tools to assist the United States in meeting the growing demand for clean, affordable energy while balancing the increasing competition for the Nation's finite supplies of fresh water resources.

In order to proceed with this effort, Sandia provided and coordinated geochemistry and desalination technical expertise to assist in assessing the changes in water quality from CO<sub>2</sub> sequestration into brackish water formations, sequestration footprint, and saline water extraction options for a region like the Four Corners Area of the Southwest.

Sandia continues to assess the water quality impacts from CO<sub>2</sub> sequestration on the brackish water desalination and treatment costs. Sandia and NETL will work together to identify water applications, treated water quality needs for each application, potential water demands, and utilization or disposal needs of the developed concentrate and any potential environmental issues or requirements that could negatively impact utilization of these approaches. The trade offs between performance and cost and the relative cost-effectiveness of different approaches will be assessed.

The third effort will be by Sandia to assess the regional applicability of the different approaches to determine the system-level benefits and opportunities for regional applications of the identified approaches for wide-spread sequestration of CO<sub>2</sub> and reductions in fresh water use through the utilization of deep saline formations.

# 1. GEOCHEMICAL IMPACTS OF UNDERGROUND CO<sub>2</sub> SEQUESTRATION IN THE SAN JUAN BASIN FORMATION

## *Geochemical Introduction*

The problem at hand is how to co-locate coal-fired power plants in the Southwest (USA) in such a way as to assess the potential for underground CO<sub>2</sub> sequestration while simultaneously making the best use of the region's limited water resources. Specific issues include: (1) can we locate porous formations for CO<sub>2</sub> sequestration that are close to existing (or likely future) power plant sites, (2) do these formations contain waters with "feasible" salinity (10-15 parts per million (ppm) total dissolved solids (TDS)) – too saline to be of drinking water use, but not so saline that waters withdrawn to accommodate CO<sub>2</sub> injection cannot be treated economically for power plant cooling use, and (3) will the sequestration activity cause changes in formation water chemistry which would impair later (or immediate) uses of the water? The San Juan Generating Station (SJGS) located in northwest New Mexico near the town of Farmington was selected as a specific study example.

The existence of suitable formations near our study site is a matter of regional geology which, fortunately, for the Colorado Plateau and San Juan Basin has been dealt with extensively in the published literature (for an excellent review see Allis et al., 2003). Further constraints on selecting formations were that they must be within 35 miles of the study area and lie at depths greater than 2500 feet (roughly) - so that the CO<sub>2</sub> can be pumped into them as a high density fluid. The second issue is more problematic in that the water chemistry may vary from place to place even in a single formation, and there may not always be a well where one wants information. However, for our purposes the data available in the NatCarb database proved sufficient (NatCarb, 2007). It is important to point out, however, that water would ideally only be removed ahead of the CO<sub>2</sub> plume (injection and production wells would be sufficiently far apart) to avoid reproducing the CO<sub>2</sub>, and that it is paramount to understand the geochemistry of the formation under consideration.

With this information in hand it was possible to evaluate whether injecting CO<sub>2</sub> into representative formations would initiate deleterious chemical changes. This assessment was made using a commercially available computational package called REACT (available as part of the "Geochemist's Workbench"; Bethke, 1998). The program basically operates by finding what mix of minerals would be in equilibrium with a particular formation water. However, the amount of insight gained from such calculations can be enhanced considerably by "suppressing" the appearance of minerals which form "too slowly" to make an appearance in a "reasonable" amount of time, and by considering mineral reaction rates as well as the equilibrium configuration of the system. Time frames of interest range from around 100 years for activities related to current power production technologies, out to 350 years, after which the build up of atmospheric CO<sub>2</sub> should no longer be a such a problem (e.g., the air-sea-earth system will have equilibrated to the present CO<sub>2</sub> levels; fossil fuels will have been consumed, one can presume the development of alternate power generation technologies, etc.).

A vast pre-existing literature exists on the geochemical changes that might be initiated by injecting CO<sub>2</sub> into the subsurface. Elegant models have been developed which couple the flow of fluids through formations with the geochemical reactions (and changes in permeability) which occur as these fluids move. These models also employ reaction kinetics as well as chemical equilibrium so it is possible to see the formation mineralogy evolve in both space and time. For examples relevant to our needs see Pruss et al., 2003 and Xu et al., 2003, 2004, 2005, 2007.

Unfortunately, most of this literature focuses on understanding the very long term distribution and timing of mineralogical changes in the formation (with their potential for trapping CO<sub>2</sub> underground for thousands of years). Short-term changes in pore water chemistry are implicit in such calculations but they are not usually reported in sufficient detail to be of use in our program. What we can take from these studies is that in the short term mineralogical reactions should be localized and not cause dramatic changes in either the formation mineralogy or pore water chemistry. Consequently, the simplified box model calculations obtainable using REACT should be adequate to supply the water chemistry needs of the current study.

## **Identification of Potential Host Formations**

The San Juan Basin contains numerous wells for hydrocarbon production, providing prima face evidence for the existence for adequate underground permeability and considerable insight into the local geologic structures. The geology near the Four Corners – San Juan power-generating complex is relatively simple (Craigg, 2000). Both plants sit on the western margin of a structural basin which deepens rapidly to the east and is filled with several thousands of feet of alternating layers of dark gray Cretaceous shales and buff-colored sandstones. West of the site what remains of the Cretaceous formations (many of the upper – younger – layers have been eroded away) thins to less than 1000 feet and older rocks are then at depths where they might be attractive sequestration targets. Once formations of interest were identified based on regional geology the next step involved extracting data on formation water chemistry, well locations and production depths from the “NatCarb” database (NatCarb, 2007). The results of this activity were then sorted to eliminate those entries where: (1) the water was too salty (greater than 15,000 TDS), (2) the wells were too shallow or deep (not between ~ 2,000 and 10,000 feet), and (3) the distance from the study site was beyond 35 miles. Tables 1-1a and 1-1b records water quality data for the six formations that met all three criteria. It is worth noting that the initial formation selection included formations with less than 10,000 TDS, and that it is recognized that for saline formations, waters with TDS less than 10,000 ppm would be undesirable for sequestration of CO<sub>2</sub>. This is to protect potential future drinking water sources, but the initial formations were included in this case study to provide the opportunity to build the model based on a formation for which a large amount of data was already available, and that future saline formation selection iterations of the model are expected to focus on waters with TDS greater than 10,000 ppm.

**Table 1-1a: Formations close to the Four Corners plants which meet coupled-use criteria.**

Depth Bottom	Depth Top	Formation	Latitude	Longitude	Radial distance from San Juan (SJ) or 4 Corners (4C) plants	
					SJ plant	4C plant
2430	2402	FRUITLAND	37.0	107.9	32.5	37.4
2412	2406	FRUITLAND	37.0	107.9	32.5	37.4
2430	2402	FRUITLAND	37.0	107.9	32.5	37.4
2812	2795	FRUITLAND	36.9	107.9	31.2	36.0
2948	2900	MESAVERDE/PICTURED CLIFFS	36.8	107.8	32.3	34.9
2209	2131	MESAVERDE/PICTURED CLIFFS	36.6	107.9	31.8	31.7
3515	3425	MESAVERDE/CLIFF HOUSE	36.6	107.9	30.7	30.0
4676	4418	MESAVERDE/POINT LOOKOUT	36.9	108.2	11.8	17.5
5034	4805	MESAVERDE/POINT LOOKOUT	36.9	108.1	18.6	23.9
5564	5546	GALLUP - SS/ in Mancos	36.6	108.1	23.3	22.6
5566	5544	GALLUP - SS/ in Mancos	36.6	108.1	23.3	22.6
5627	5606	GALLUP - SS/ in Mancos	36.7	108.1	22.6	21.9
5662	5646	GALLUP - SS/ in Mancos	36.7	108.1	21.6	20.9
5556	5534	GALLUP - SS/ in Mancos	36.7	108.1	20.8	20.3
4940	4886	GALLUP - SS/ in Mancos	36.7	108.3	9.8	9.6
	4476	GALLUP - SS/ in Mancos	36.8	108.4	2.9	6.8
4345	4320	GALLUP - SS/ in Mancos	36.8	108.4	2.6	6.6
2039	1992	DAKOTA	36.9	108.6	7	13
?	1730	DAKOTA	36.7	108.6	11	5
6150	6039	DAKOTA	36.5	108.2	21	17
6257	6104	DAKOTA	36.6	107.9	33.8	33.0
6710	6547	DAKOTA	36.6	107.9	32.4	31.5
	6340	DAKOTA	36.6	107.9	30.3	29.4
6492	6333	DAKOTA	36.6	107.9	32.0	31.6
6195	5990	DAKOTA	36.6	108.0	28.1	27.4
1493	1492	DAKOTA	36.8	108.6	7.5	9.7
6436	6137	DAKOTA	36.8	108.1	20.0	22.9
6941	6774	DAKOTA	36.8	108.0	25.8	28.8
2039	1992	DAKOTA	36.9	108.6	8.0	13.6
3632	3558	DAKOTA	36.9	108.5	8.7	16.6
5254	4730	DAKOTA	37.0	107.9	31.9	36.9
5254	4730	DAKOTA	37.0	107.9	31.9	36.9
4725	4715	MORRISON	36.8	108.5	3	7
4725	4715	MORRISON	36.8	108.5	3.5	8.1
9001	8965	HERMOSA/PARADOX	36.9	108.3	11	19
9001	8965	HERMOSA/PARADOX	36.9	108.3	11	19
9001	8965	HERMOSA/PARADOX	36.9	108.3	11	19
9001	8965	HERMOSA/PARADOX	36.9	108.3	11.7	19.5

Depth Bottom	Depth Top	Formation	Latitude	Longitude	Radial distance from San Juan (SJ) or 4 Corners (4C) plants	
					SJ plant	4C plant
9001	8965	HERMOSA/PARADOX	36.9	108.3	11.7	19.5
9001	8965	HERMOSA/PARADOX	36.9	108.3	11.7	19.5
9445	9390	HERMOSA/PARADOX	36.9	108.3	10.7	18.3
9504	9466	HERMOSA/PARADOX	36.9	108.3	10.7	18.3
<b>Power Stations at:</b>			<b>36.8</b>	<b>108.5</b>	5	5

**Table 1-1b: Formations close to the Four Corners plants which meet coupled-use criteria.**

Formation	pH	ppm or mg/kg						
		TDS	Na	Ca	Mg	Cl	SO <sub>4</sub>	HCO <sub>3</sub>
FRUITLAND	8.2	13736	3926	70	13	1450	5.5	8272
FRUITLAND	8.5	12191	3968	5	54	2740	6.8	5417
FRUITLAND	8.4	13602	4050	44	27	1460	5.6	8015
FRUITLAND	8.6	18587	5798	48	12	922	6.8	11800
MESAVERDE/PICTURED CLIFFS	8.7	7810	2907	45	9	4000	7.0	842
MESAVERDE/PICTURED CLIFFS	8.2	8116	2955	70	15	4300	7.3	769
MESAVERDE/CLIFF HOUSE	8.2	4917	2096	78	44	1900	5.7	793
MESAVERDE/POINT LOOKOUT	7.9	4447	1572	87	28	2500	4.2	256
MESAVERDE/POINT LOOKOUT	7.8	5310	1955	18	5	2623	4.6	704
GALLUP - SS/ in Mancos	8.2	6250	2763	16	9	2540	7.0	915
GALLUP - SS/ in Mancos	8.5	3297	1240	5	1	1060	2.6	988
GALLUP - SS/ in Mancos	8.3	4312	1962	19	5	1260	4.8	1061
GALLUP - SS/ in Mancos	8.3	5712	2467	29	7	2020	6.1	1183
GALLUP - SS/ in Mancos	8.3	3609	1802	20	4	1180	4.7	598
GALLUP - SS/ in Mancos	7.7	5221	1929	130	19	2563	5.1	575
GALLUP - SS/ in Mancos	8.4	9145	3378	8	7	4060	7.7	1684
GALLUP - SS/ in Mancos	7.9	13240	4817	71	65	6250	11.6	2025
DAKOTA	8.9	5983	2120	10	5	1980	916	952
DAKOTA	8.4	3673	1159	21	14	281	1942	256
DAKOTA	7.9	14791	4964	167	30	4182	4178	1270
DAKOTA	7.7	11464	4123	155	43	6400	10.7	732
DAKOTA	7.9	3796	1299	103	23	1990	3.5	378
DAKOTA	8.1	15166	5647	126	20	7700	13.9	1659
DAKOTA	6.8	6921	2404	236	28	4100	6.8	146
DAKOTA	6.4	4802	1764	80	18	2740	4.7	195
DAKOTA	8.8	1804	1175	21	13	251	3.3	341
DAKOTA	8.5	8922	4980	40	18	2600	13.9	1270
DAKOTA	7.4	12040	4504	259	18	6600	12.1	647
DAKOTA	8.9	5072	2120	10	5	1980	5.0	952

		ppm or mg/kg	ppm or mg/kg	ppm or mg/kg	ppm or mg/kg	ppm or mg/kg	ppm or mg/kg	ppm or mg/kg
Formation	pH	TDS	Na	Ca	Mg	Cl	SO <sub>4</sub>	HCO <sub>3</sub>
DAKOTA	8.6	2083	741	16	10	356	1.4	959
DAKOTA	7.5	6950	2149	560	11	3900	7.0	323
DAKOTA	7.1	9014	2974	657	12	4850	9.4	512
MORRISON	7.9	5947	1491	313	49	58	3764	272
MORRISON	7.9	2189	1491	313	49	58	5.7	272
HERMOSA/PARADOX	8	10164	2802	368	49	425	5800	720
HERMOSA/PARADOX	8	9762	2686	368	39	425	5500	744
HERMOSA/PARADOX	8	9704	2654	368	49	425	5500	708
HERMOSA/PARADOX	8	4373	2802	368	49	425	9.4	720
HERMOSA/PARADOX	8	4271	2686	368	39	425	9.0	744
HERMOSA/PARADOX	8	4213	2654	368	49	425	9.0	708
HERMOSA/PARADOX	7.5	7846	3578	285	155	1110	10.3	2708
HERMOSA/PARADOX	8	12282	5205	310	93	3333	13.8	3327
		<b>Power Stations at:</b>	<b>Latitude 36.8</b>	<b>Long. 108.5</b>	5	5		

## Geochemical Modeling – Lithology and Mineralogy

The formations identified in Tables 1-1a and 1-1b can basically be divided into four groups: (1) the lower Tertiary/upper Cretaceous near-shore and continental shale-sandstone-coal mixture of sediments in the Fruitland formation (source of the coal that fuels local power plants), (2) Cretaceous beach sands (Dakota sandstone and the sandstone interbeds in the Mancos and Mesa Verde shale units) comprised of relatively fine-grained well sorted quartz beach sandstones with variable amounts of clay, (3) the Jurassic Morrison formation which originated as a river delta complex (e.g., sandstones that also contain a lot of gravel-sized pieces) units (ca 150-100 million years old), and (4) the Pennsylvanian (ca 320 to 290 million years old) interbedded limestones and shales of the Hermosa Group. The differing mineralogic makeup of these formations may play an important role in their response to CO<sub>2</sub>.

Detailed site-specific mineralogical descriptions are difficult to find. However, over the years field geologists have arrived at some generalizations about the mineralogy of shales in this region which proved quite useful in developing the mineralogic profiles needed for our study. Speaking generally of the occurrence of Cretaceous clays in the Rocky Mountain region Weaver (1989) notes a proclivity for kaolinite in deltaic sediments, which is replaced by a higher proportion of illite or mixed-layer illite-smectite in sediments deposited under open marine conditions. The input of volcanic materials and absence of deep burial both favor an abundance of smectite (a.k.a., “montmorillonite”, “bentonite”).

The youngest (and shallowest) formation in play is the Fruitland which is comprised of a complex mix of sandstone, shale and coal formed in a deltaic environment. Of particular interest here are the sands, which Lucas et al., 2006, describes as being fine to medium grained and

subarkosic (e.g., contains a small proportion of feldspar). Siderite (iron carbonate) concretions are also reported from this formation. Kaolinite and illite are the most abundant clays but occasionally one finds reports of smectite (Fowler et al., 1996; Riese and Ring, 1996). The proportions of different minerals used to represent this formation in our modeling are given in Table 1-2, column 2.

Somewhat older are the Dakota Sandstone and the sandy interlayers units in the otherwise shaley Mancos (Gallup sandstone) and Mesa Verde (Point Lookout sandstone) formations. These units were deposited in open beach-like environments (rather than deltaic settings) as the region repeatedly rose and sank beneath sea level. As such, they consist mostly of well-sorted quartz sands admixed with various clays, some calcite cement, and essentially no feldspar. Brookins, 1982, suggests that kaolinite is the principal clay in sandy parts of the Dakota and fills ~ 25% of the volume (quartz presumably comprising the remainder). When the principal lithology is shale, however, smectite is more abundant than kaolinite. White et al., 1995 also suggest that the Dakota contains about equal proportions of quartz, kaolinite and Na-smectite, but does not differentiate between the sandy and shaley members of the unit. Because of their greater porosity (and potential for CO<sub>2</sub> sequestration) the kaolinite-rich mineralogy appropriate to sandstone was favored in assigning mineralogies to the Dakota, Gallup and Point Lookout sandstones (Table 1-2, column 3).

In contrast, the Morrison, returns to environments similar to the Fruitland in that it contains relics of numerous buried stream and delta deposits, has less quartz, and more of the other minerals represented in Table 1-2 (see column 4 for assigned proportions). The formation also received considerable amounts of volcanic ash from the mountains forming to the west. White, et al., 2005 suggest a lithology comprised of 13% Na- smectite, 2% calcite, 1% dolomite, 13% kaolinite, 65% quartz and 1% each of illite magnetite and hematite – with 2% porosity. Brookins, 1982, provides additional insights into the clay mineralogy of the Morrison, suggesting that illite-montmorillonite and kaolinite are the principal clays, and kaolinite tends to be more abundant in the sandy parts of the formation. A minor occurrence of chlorite-group minerals is also indicated. Total clay content in the more sandy (more porous) units from ranges from less than 5% to about 20%. Mineral proportions for the Morrison (Table 1-2, Column 4) were developed to accommodate these inputs. The Morrison is also somewhat unusual in that it contains abundant uranium deposits which potentially could be mobilized by injecting oxygenated waters charged with CO<sub>2</sub> (the typical mix used for extracting uranium during in-situ mining). This is not an immediate concern but may need to be addressed in the context of a larger, longer duration program.

For the Hermosa, White et al., 2005, suggest a mineralogy which is principally (by volume) quartz (~47 %), dolomite (~28%) and kaolinite (~16%) with the remaining 9% being accounted for as porosity. Neither illite nor calcite appears as significant constituents in this assessment; both omissions seem unlikely. Alternatively, at exposures on the south flank of the San Juan Mountains near Durango, Barns 1992, describes the formation as consisting of “thin inter-layered gray sandstones, shales and limestones,” *with no mention of dolomite*. In the same area Brown, 2002, describes limestone (presumably calcite rather than dolomite) and sandstones comprised largely of quartz and feldspar (presumably K-feldspar from the context of the descriptions) with an abundance of calcite cement in addition to whatever dolomite may be

present. Girdley, 1968, and Wingerd and Szabo, 1968, confirm the prominent occurrence of limestone outcrops on the south flank of the San Juan Mountains, but not dolomite. The resolution of the calcite-dolomite issue may lie in the fact that White, et al., 2005, refers to exposures in southeast Utah, close to the Paradox Basin evaporates (rock salt) and a source for the magnesium needed to convert the limestone to dolomite. This transformation would not have occurred further south where the San Juan basin later developed.

Relative to the identity of the Hermosa clays, Weaver, 1989, describes the marine rocks overlying the Molas unconformity (a prominent stratigraphic marker immediately underlying both the Belden and Hermosa formations) as being comprised of “predominantly illite and I/S {illite-smectite mixtures} and lesser amounts of chlorite and kaolinite.” The proportions of different minerals selected for modeling in the Hermosa (Table 1-2, column 5) favor a mineralogy that is characteristic of the southern exposures and contains calcite rather than dolomite.

**Table 1-2: Proportions of different minerals in modeled formations.**

Mineral	% in Fruitland	% in Dakota Mesa Verde Mancos	% in Morrison	% in Hermosa (sandy units)
Quartz SiO <sub>2</sub>	55%	70 % (Balance)	60% (Balance)	35% (Balance)
K-Feldspar KAlSi <sub>3</sub> O <sub>8</sub>	5%	0	5%	5%
Albite (Na-Feldspar) NaAlSi <sub>3</sub> O <sub>8</sub>	5%	0	5%	0
Calcite CaCO <sub>3</sub>	5% as cement	5% (as cement)	5% (as cement)	30%
Dolomite CaMg(CO <sub>3</sub> ) <sub>2</sub>	0	0	0	5%
Illite K <sub>0.6</sub> Mg <sub>0.25</sub> Al <sub>2.3</sub> Si <sub>3.5</sub> O <sub>10</sub> (OH) <sub>2</sub>	10%	5%	5%	10%
Chlorite (“Ripidolit-14A”) Fe <sub>2</sub> Mg <sub>3</sub> Al <sub>2</sub> Si <sub>3</sub> O <sub>10</sub> (OH) <sub>8</sub>	0	0	5%	5%
Low-Fe-Mg Smectite Na <sub>0.15</sub> Ca <sub>0.02</sub> K <sub>0.2</sub> Mg <sub>0.9</sub> Fe <sub>0.45</sub> Al <sub>1.25</sub> Si <sub>3.75</sub> O <sub>10</sub> (OH) <sub>2</sub>	5%	5%	5%	0
Kaolinite Al <sub>2</sub> Si <sub>2</sub> O <sub>5</sub> (OH) <sub>4</sub>	10%	15%	10%	10%
Siderite FeCO <sub>3</sub>	5%	0	0	0

### Geochemical “Box Models”

There are several levels at which one may approach the problem of modeling what will happen when a mix of CO<sub>2</sub>, brine, and rock are “put in a box” and allowed to react. The easiest approach is to simply let the computer program find the equilibrium configuration of the “system” (e.g., the most chemically stable arrangement for the mix of elements implicit in the proportions of gas, brine and rock provided to the model). To accomplish even this calculation,

though, it was necessary to complete the water analysis selected from Table 1-1 (see Table 1-3) by adding concentrations for several minor and trace constituents:  $K^+$  (10 ppm),  $SiO_2(aq)$  (6 ppm),  $Al^{+++}$  (0.005 ppm), and  $Fe^{+++}$  (0.0005 ppm) in amounts one might generally expect for such formation waters. The actual values selected, however, were of no consequence to the outcome because ultimately it is the chemistry of the rocks in the formation which fix these variables, and not what was added in the initial pore fluid. It was also assumed that 125 grams of  $CO_2$  would be reacted with one liter of brine plus the various amounts of minerals presumed to be in the system. This amount of gas was chosen because at the beginning of the calculation (and, as it turned out, at the end as well) the pressure would be in the range compatible with the need to pump the gas as a high-density fluid.

**Table 1-3: Water chemistries selected for modeling.**

Formation/Water Source	TDS (ppm)	pH	Na (ppm)	Ca (ppm)	Mg (ppm)	Cl (ppm)	$SO_4$ (ppm)	$HCO_3$ (ppm)
FRUITLAND	13602	8.4	4050	44	27	1460	5.6	8015
MESAVERDE/POINT LOOKOUT	4447	7.9	1572	87	28	2500	4.2	256
GALLUP - SS/ in Mancos	9145	8.4	3378	8	7	4060	7.7	1684
DAKOTA	2083	8.6	741	16	10	356	1.4	959
MORRISON	5947	7.9	1491	313	49	58	3764	272
HERMOSA/PARADOX	4213	8.0	2654	368	49	425	9.0	708

One way to make such models much more informative is to “suppress” the appearance of minerals that are unlikely to appear in the time frame of interest (~ 100 - 350 years). Of particular relevance to this study are the treatments accorded quartz, magnesium-rich silicates (“saponites” and various forms of chlorite, other than ripidolit), and the carbonate mineral dolomite. Quartz was assumed to be the stable form of silica since it is abundant in these formations. However, one might also argue that during short term precipitation processes the level of dissolved silica would be higher and reflect saturation with amorphous silica rather than quartz. In the future we might want to investigate the implications of this choice since dissolved silica has a strong impact on desalinization processes.

Dolomite presents a problem similar to that of quartz in that in the ordered form it is quite insoluble, but does not form quickly in nature. However, its hypothetical formation in a calculation will quickly scavenge both magnesium and calcium from pore waters and some preliminary calculations indicated that it was predicted even in some settings where field studies indicate its absence. Consequently ordered forms of dolomite were suppressed in preference to the (less stable) disordered form, which is more soluble but has been observed precipitating even in short term experiments. As noted above, the dolomite issue is of special importance for the Hermosa formation, but it was handled by assuming that for our purposes the formation is comprised of calcite (“limestone”) rather than dolomite (Table 1-3).

The treatment accorded the large number of magnesium silicates in the REACT database also needs to be documented. In preliminary runs it was found that unless various forms of saponite

(a magnesium-rich smectite clay) and most forms of chlorite were suppressed the computer would immediately “transform” all of the low Fe-Mg-smectite and ripidolite put initially into the model to various forms of chlorite and saponite (along with producing a fair amount of kaolinite). The ensuing computations then gave no indication of how the minerals that were actually indigenous to the formation would react over time. For this reason the computations suppressed the formation of such silicates, allowing only a low Fe-Mg-smectite and a single chlorite mineral (ripidolite) to form or dissolve.

A final step in making the models more realistic is to also ask how quickly things will change, rather than just tabulating the final equilibrium condition of the system. With this approach some minerals will react faster than others and, consequently, they may have impacts which exceed what one might expect from the bulk amounts put initially into the model. Minerals such as quartz and various feldspars react more slowly than clays (and chlorite). Carbonates, sulfates and simple hydroxides may react so rapidly that they will equilibrate immediately with whatever brines form as the model progresses.

To apply such an approach, however, requires that the reaction rates (moles per cm<sup>2</sup> per second) and specific surface areas (cm<sup>2</sup> per gram) be specified for each “kinetic” mineral. Most of the rate constants (Table 1-4) used in these models came from recent publications originating at Lawrence Berkeley National Laboratory (LBL) (Pruss et al., 2003 and Xu et al., 2003, 2004, 2005, 2007). Some specific surface areas used were also taken from these works, or alternately they were derived from the geometric surface areas of presumably perfectly spherical (silt sized) sand grains. It is noteworthy that neither the reaction rates (of essentially idealized phases) nor the specific surface areas can be specified with any great level of certainty. The outcomes of the resulting calculations, therefore, have sizeable uncertainties associated with them.

**Table 1-4: Kinetic parameters used in modeling rock – carbonated brine interactions.**

<b>Mineral</b>	<b>Rate - moles per cm<sup>2</sup> per second</b>	<b>Surface Area - cm<sup>2</sup> per gram</b>
Quartz	1.26x10 <sup>-18</sup>	37
K-feldspar	1.00x10 <sup>-16</sup>	100
Calcite	1.60x10 <sup>-13</sup>	2000
Kaolinite	1.00x10 <sup>-17</sup>	5000
Illite	1.00x10 <sup>-18</sup>	5000
Ripidolit- 14A	1.00x10 <sup>-17</sup>	1000
Dolomite	1.60x10 <sup>-13</sup>	2000
Smectite- low-Fe-Mg	1.00x10 <sup>-18</sup>	10000

## Box Model Results

The basic box equilibration calculations were performed in two steps. First, just the water (and a pinch of quartz) were equilibrated with 125 grams of CO<sub>2</sub>. This produced a rather acidic fluid which was then brought in contact with the minerals presumed to be in the rock (totaling about 1 kg) under various circumstances. Tables are provided showing both the resulting water chemistry and mineralogic makeup over time for each formation – ground water pair identified above. In each formation, the following water chemistry characteristics are provided (from left to right in the tables):

1. The water chemistry that would result when the natural, uncarbonated, hypothetical water is allowed to equilibrate with the hypothetical minerals presumed to be in that formation. This serves as a check that there is not gross disequilibrium in the system before the calculation even starts adding any CO<sub>2</sub>.
2. The water chemistry which results when just CO<sub>2</sub> is added to the starting fluid; essentially the fluid chemistry which would form immediately upon mixing of the formation water with the CO<sub>2</sub>.
3. The water chemistry resulting after 100 years of contact time.
4. The water chemistry resulting after 350 years of contact time.
5. The formation water chemistry after a very long time has passed when the minerals and carbonated solutions have finally equilibrated completely.

In each case, tables 1-5 to 1-10 ‘a’ gives information on how the formation chemistry changes and the water mineralogy is given in tables 1-5 to 1-10 ‘b’. The initial makeup that went into the model is given first (left column), followed by the formation mineralogy after 100 years, 350 years, and at final equilibrium. The top grouping of entries at each time reflects what happens (inventoried in grams) to the minerals which were initially part of the rock. These minerals may increase in abundance, decrease, or disappear all together depending on how the reactions progress. The lower grouping is the new minerals that appear (and then occasionally disappear later on) during the calculation. The mineralogical information is mostly of academic interest for the present study. However, if a later study progressed to the point where changes in formation porosity (and hence permeability) became important it would be of vital importance.

## **Geochemical Analysis Conclusions**

Not unexpectedly, the first reactions predicted are the dissolution of carbonate minerals (calcite >> dolomite and siderite). These are rapid and account for much of the change in ground water chemistry that would be observed in the first centuries after putting CO<sub>2</sub> into a deep saline formation. If the brine already also contains sufficient sulfate then the calcium derived from the calcite dissolution may build up to the point where gypsum precipitates (Morrison and Hermosa). Generally, only small amounts of secondary minerals form in the first few centuries and no significant sequestration of CO<sub>2</sub> in a mineral form would be expected. Consequently, if these waters were returned to the surface essentially all of the CO<sub>2</sub> placed underground could return with them. In addition to having to deal with elevated calcium levels, any attempt to desalinate these waters would also have to contend with high silica and iron concentrations. Distinctly acidic pH values would also be expected to persist for many centuries even in the presence of excess calcite. Due to these issues, the plan would be for water production to be ahead of the CO<sub>2</sub> plume to prevent these issues from becoming substantial concerns.

Over the very long term the carbonated waters and the formation mineralogy would fully equilibrate. This produces a situation which is distinctly different from what would appear after just a few centuries. In this final analysis, the solutions would still be slightly acidic, but potassium and magnesium would now be greatly enriched, while calcium and sodium would be depleted. A significant amount of CO<sub>2</sub> would now also be sequestered in a mineral form due to the precipitation of dawsonite [NaAl CO<sub>3</sub> (OH)<sub>2</sub>]. Detailed results for the individual formations are discussed below.

### **The Morrison Formation**

This is perhaps the most attractive deep saline formation in the region (Stone, 2002) because it is the most widely evaluated, has more storage resource than the other formations, and is generally well understood so it is discussed in some detail here. This discussion also sets the stage for the much briefer discussions that accompany the results for the other formations. After a great many millennia the formation would finally equilibrate and the resulting solution would be relatively depleted in sodium and sulfate but enriched in magnesium, potassium and iron; the pH increase from about 3.5 to 5.3. The mineralogy of the formation would also undergo significant alterations. Quartz and kaolinite actually increase while much, *but not all*, of the calcite and K-feldspar initially in the system are consumed – along with all of the other clays and the albite. In their place several new minerals have appeared. When added to the amounts of quartz and kaolinite that formed it is likely that the formation porosity would have actually decreased. Also, the appearance of siderite, dawsonite and disordered dolomite shows that eventually a significant amount of carbon would be sequestered in a mineral form.

These results contrast with what was predicted for the first few centuries after sequestration as shown in Tables 1-5a and 1-5b. For these shorter times sulfate still decreases, but not as much, and the principal cations responsible for the overall TDS load in the solution are now sodium and calcium. Silica and iron concentrations are also now elevated to levels that could be really

problematic for water treatment processes. In the short term most of the minerals initially present in the formation are still there, and there is no net trapping of CO<sub>2</sub> in a mineral form. The pH of this water would also still be distinctly acid despite the fact that it had equilibrated with calcite. The changes described above are also illustrated Figures 1-1 and 1-2. From these figures it becomes evident how slowly the systems actually evolve after the first 50 years, and why one should be hesitant when considering underground CO<sub>2</sub> sequestration in a mineralized form in saline formations if the relevant time frame is just a few hundred years.

**Table 1-5a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Morrison formation.**

<b>Morrison - Water Chemistry</b>					
All values	Test Water	Test Water	Test Water	Test Water	Test Water
in parts per	Equilibrates	plus CO <sub>2</sub>	plus CO <sub>2</sub>	plus CO <sub>2</sub>	equyilibrates
million	with rock	- no rock	and rock for	and rock for	fully with CO <sub>2</sub>
	no CO <sub>2</sub>		100 years	350 years	and rock
Aluminum	0.061	0.004	0.008	0.007	0.004
Calcium	10.5	278	1767	1609	404
Carbon	32	30210	30700	30510	22220
Chlorine	70.8	63.0	62.8	62.8	65.1
Iron	0.003	0.000	29.7	27.1	7.3
Magnesium	5.8	43.6	178	505	786
Potassium	2.6	8.9	77	173	5845
Silicon	3.2	2.4	21.8	21.7	2.4
Sodium	1516	1326	1343	1393	194.2
Sulfate	2995	3351	2096	2660	963
pH	8.70	3.49	4.84	4.88	5.31

**Table 1-5b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Morrison formation.**

<b>Mineral Composition of Morrison</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>	<b>remaining</b>			
Albite	45	45	44	0.0
Calcite	45	39	40	13.2
Illite	45	45	44	0.0
K-feldspar	45	45	44	20.5
Kaolinite	90	91	93	158
Quartz	540	540	540	619
Ripidolit-14A	45	44	42	0.0
Smectite-low-Fe-	45	44	43	0.0
<b>New Minerals</b>	N/A			
Siderite	N/A	0.34	1.36	20.7
Goethite	N/A	0.022	0.077	1.63
Dolomite-deis	N/A	0	0	58.5
Dawsonite	N/A	0	0	35.3
Alunite	N/A	0	0	5.97
Clinoptil-Ca	N/A	1.00	3.20	0.00
Gypsum	N/A	2.53	0	0.00

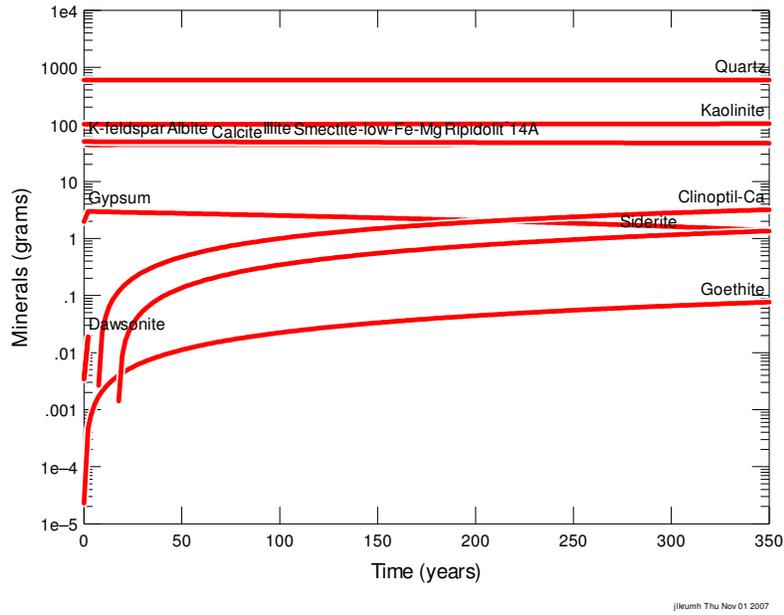


Figure 1-1: Minerals present in the system for the first 350 years.

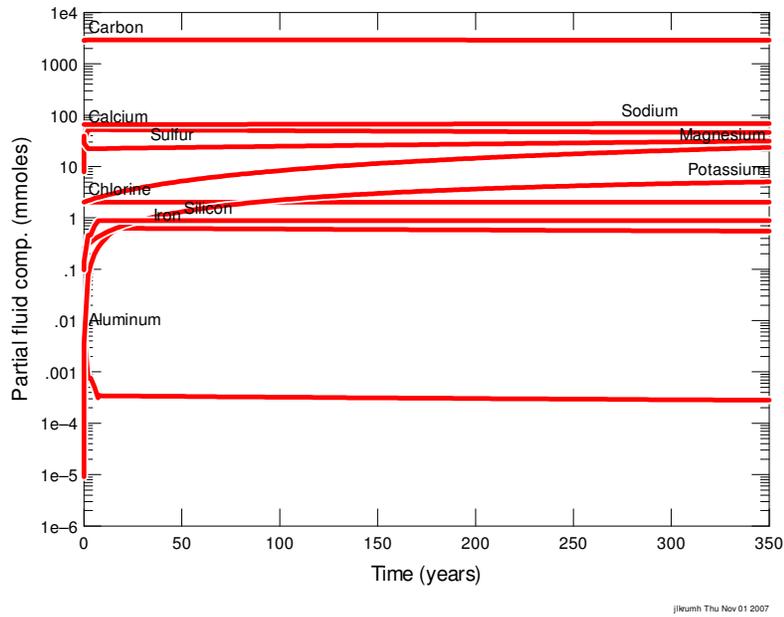


Figure 1-2: Evolution of fluid chemistry in the first 350 years.

## Hermosa Formation

One may expect the Hermosa Formation with its large percentage of calcite to react more extensively than the Morrison. This expectation, however, is not born out because calcite dissolution is arrested after only about 8% of the calcite present has dissolved. In fact, changes seen in the Morrison carry over to this case in spite of its vastly different mineralogy as shown in Tables 1-6a and 1-6b. Early on, the principal cations are calcium and sodium, while at equilibrium they are replaced by Mg and K. Sulfate, decreases from several thousand ppm early on, to a little less than 1000 ppm at equilibrium, and gypsum saturation is a persistent feature for the first few centuries. The behaviors of silica and iron are also the same as with the Morrison, and, CO<sub>2</sub> will not be trapped in a mineral form during the first few centuries.

**Table 1-6a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into a Hermosa limestone.**

<b>Hermosa Water Chemistry - no indigenous dolomite but disordered dolomite may precipitate</b>					
<b>All values in parts per million</b>	Test Water Equilibrates with rock - no CO <sub>2</sub>	Test Water plus CO <sub>2</sub> - no rock	Test Water plus CO <sub>2</sub> and rock for 100 years	Test Water plus CO <sub>2</sub> and rock for 350 years	Test Water equilibrates fully with CO <sub>2</sub> and rock
Aluminum	0.013	0.004	0.007	0.006	0.004
Calcium	147	328	1587	1493	429
Carbon	14	30190	30780	30610	25040
Chlorine	427	378	378	378	387
Iron	0.031	0.000	26.6	25.0	7.7
Magnesium	324	44	152	414	827.5
Potassium	14	9	80	178	6349
Silicon	2.8	2.4	21.6	21.5	2.3
Sodium	1929	2362	2358	2357	184
Sulfate	5055	4899	2587	3078	831
pH	8	3.83	4.8	4.81	5.28

**Table 1-6b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into a Hermosa limestone.**

<b>Mineral Composition of Hermosa Limestone</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>				
Calcite	350	343.6	344.4	322.5
Illite	100	99.4	97.9	0.0
K-feldspar	50	49.7	49.5	36.7
Kaolinite	100	100.9	102.8	181.1
Quartz	350	350.0	350.1	390.2
Ripidolit-14A	50	49.0	46.7	0.0
<b>New Minerals</b>				
Alunite	N/A	0.0	0.0	10.0
Dawsonite	N/A	0.0	0.0	15.5
Dolomite-dis	N/A	0.0	0.0	50.1
Goethite	N/A	7.90E-07	7.91E-07	7.98E-07
Siderite	N/A	0.30	1.178	18.7
Clinoptil-Ca	N/A	0.51	1.456	0.0
Gypsum	N/A	4.69	3.688	0.0

## Fruitland Formation

The Fruitland formation is the most distant, deepest and saline of the formations evaluated. However, it is also a formation which has received considerable attention from the standpoint of producing sub-grade water (Stone, 2002) that may have future uses. In terms of fluid chemistry, the pattern is familiar, early high Ca and Na ultimately being replaced with K and Mg; early high iron and silica also were again predicted as shown in the results presented in Tables 1-7a and 1-7b. What is interesting here is the early appearance of dawsonite – a signature mineral for sequestering CO<sub>2</sub> in a non-gaseous form. The early appearance of dawsonite arises from the high proportion of reactive clays (which can, in turn, be traced to the young age of the formation). Unfortunately, the amounts of dawsonite formed fail to offset the lost calcite so there has not actually been a net mineralization sequestration of CO<sub>2</sub> as a mineral.

**Table 1-7a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Fruitland formation.**

<b>Fruitland Sandstones - Water Chemistry</b>					
<b>All values in parts per million</b>	Test Water	Test Water	Test Water	Test Water	Test Water
	Equilibrates	plus CO <sub>2</sub>	plus CO <sub>2</sub>	plus CO <sub>2</sub>	equilibrates
	with rock	- no rock	and rock for	and rock for	fully with CO <sub>2</sub>
	no CO <sub>2</sub>		100 years	350 years	and rock
Aluminum	0.031	0.003	0.001	0.002	0.006
Calcium	3.1	39.2	1134	1306	566
Carbon	168	31250	31360	31120	25620
Chlorine	4041	3542	3537	3546	3645
Iron	0.05	0.00	19.4	22.2	9.9
Magnesium	5.5	24.1	62.3	157	1047
Potassium	4.9	8.9	90.2	210.8	7511
Silicon	3.0	2.3	24.5	23.4	2.3
Sodium	2931	4968	4563	3803	205
Sulfate	0.003	4.1	4.1	4.1	4.2
pH	8.40	4.85	4.96	4.99	5.2

**Table 1-7b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Fruitland formation.**

<b>Mineral Composition of Fruitland Sandstones</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>				
Albite	50	49.8	49.3	0.0
Calcite	50	46.5	45.3	35.5
Illite	100	99.4	97.9	0.0
K-feldspar	50	49.7	49.6	41.3
Kaolinite	100	97.3	92.3	169
Quartz	550	550	550	642
Siderite	50	50.0	50.1	54.3
Smectite	50	49.4	47.9	0.0
<b>New Minerals</b>				
Dawsonite	N/A	3.00	8.87	64.4
Dolomite-dis	N/A	0.00	0.00	24.6
Goethite	N/A	0.02	0.08	1.81
Clinoptil-Ca	N/A	3.24	9.76	0.00

### **Dakota, Mesa Verde, and Mancos Formations**

These formations are grouped together because they all have similar mineralogy (indeed identical in the model) being comprised mostly of clean quartz sand with small amounts of clay and calcite cement. In terms of the modeling effort the only differences are the input solutions used and the highlights of the Dakota formation are shown in Tables 1-8a and 1-8b. Additionally, the Mesa Verde results are shown in Tables 1-9a and 1-9b whereas the Mancos results are shown in

Tables 1-10a and 1-10b. All of the waters start out as dilute NaCl brines with the concentrations increasing in the order Dakota, Mesa Verde, Mancos. In the short term, calcite dissolution is the principal reaction, and in the long term the destruction of illitic and smectite clay again drive the changes in fluid chemistry. This gives rise to the familiar pattern of early calcium enrichment that is later replaced fluids enriched in potassium and magnesium. Sodium levels remain relatively constant for the first few centuries but are diminished significantly as final equilibrium is approached.

### Dakota Sandstone

**Table 1-8a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Dakota formation.**

<b>Dakota Sandstone - Water Chemistry</b>					
<b>All values in parts per million</b>	Test Water	Test Water	Test Water	Test Water	Test Water
	Equilibrates	plus CO <sub>2</sub>	plus CO <sub>2</sub>	plus CO <sub>2</sub>	equilibrates
	with rock - no CO <sub>2</sub>	- no rock	and rock for 100 years	and rock for 350 years	fully with CO <sub>2</sub> and rock
Aluminum	0.132	0.004	0.005	0.005	0.004
Calcium	0.90	14.2	1743	1743	429.1
Carbon	71.4	30430	30810	30810	25040
Chlorine	635	564	562	562	387
Iron	0.000	0.000	22.4	22.4	7.7
Magnesium	2.0	8.9	43	43	828
Potassium	0.91	8.9	36	36	6349
Silicon	3.5	2.5	22.5	22.5	2.3
Sodium	555	659	661	661	184
Sulfate	1.40	1.25	1.24	1.24	831
pH	9.07	4.04	4.79	4.81	5.28

**Table 1-8b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Dakota formation.**

<b>Mineral Composition of Dakota Sandstone</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>				
Calcite	50	45	45	39
Illite	50	50	49	0
Kaolinite	150	150	151	204
Quartz	700	700	700	731
Smectite-low-Fe-	50	49	48	0
<b>New Minerals</b>				
Dawsonite		0	0	5.99
Dolomite-dis		0	0	17.5
Goethite		0.022	0.077	1.81
Siderite		0	0.114	4.26
Clinoptil-Ca		0.37	1.47	0

**Mesa Verde Formation (Gallup Sandstone)**

**Table 1-9a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into a Mesa Verde sandstone interlayer saline formation.**

<b>Mesa Verde Sands - Water Chemistry</b>					
All values in parts per million	Test Water	Test Water	Test Water	Test Water	Test Water
	Equilibrates	plus CO2	plus CO2	plus CO2	equilibrates
	with rock - no CO2	- no rock	and rock for 100 years	and rock for 350 years	fully with CO2 and rock
Aluminum	0.034	0.004	0.006	0.006	0.010
Calcium	18.3	77.4	2056	1942	748
Carbon	18.18	30250	30690	30670	28460
Chlorine	2520	2241	2229	2230	2250
Iron	0.00	0.00	22.4	32.9	13.1
Magnesium	40	25	59	144	1421
Potassium	4.2	8.9	35.9	102	3613
Silicon	3.0	2.4	22.1	22.1	2.3
Sodium	1572	1398	1396	1408	227.1
Sulfate	4.2	3.7	3.7	3.7	3.8
pH	8.44	3.45	4.78	4.8	5.093

**Table 1-9b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into a Mesa Verde sandstone interlayer saline formation.**

<b>Mineral Composition of Mesa Verde Sands</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>				
Calcite	50	44.4	44.5	40.09
Illite	50	49.7	49.1	0
Kaolinite	150	150.4	151.1	199.3
Quartz	700	700.0	700.2	733.2
Smectite	50	49.4	48.1	0
<b>New Minerals</b>				
Dawsonite	N/A	0.0	0	11.1
Dolomite-dis	N/A	0.0	0	15.3
Goethite	N/A	0.022	0.069	1.81
Siderite	N/A	0	0.086	4.25
Clinoptil-Ca	N/A	0.37	1.32	0

**Mancos Formation (Point Lookout Sandstone)**

**Table 1-10a: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Mancos sandstone saline formation.**

<b>Mancos Sands - Water Chemistry</b>					
<b>All values in parts per million</b>	Test Water	Test Water	Test Water	Test Water	Test Water
	Equilibrates	plus CO2	plus CO2	plus CO2	equilibrates
	with rock - no CO2	- no rock	and rock for 100 years	and rock for 350 years	fully with CO2 and rock
Aluminum	0.034	0.004	0.005	0.005	0.014
Calcium	23.4	7.1	1859	1759	916
Carbon	19.0	30370	30780	30760	28080
Chlorine	4260	3780	3762	3763	3810
Iron	0.000	0.000	22.3	29.4	15.7
Magnesium	47.8	6.2	40.5	124	1709
Potassium	4.5	8.9	35.8	102	3610
Silicon	3.0	2.4	21.8	21.8	2.3
Sodium	2683	3006	2996	3008	250.8
Sulfate	7.7	6.9	6.8	6.8	6.9
pH	8.43	4.21	4.83	4.85	5.05

**Table 1-10b: Changes in formation water chemistry and mineralogy when CO<sub>2</sub> is injected into the Mancos sandstone saline formation.**

<b>Mineral Composition of Mancos Sands</b>				
	grams at	grams after	grams after	grams after
	start of	100 years	350 years	full
	calculation			equilibration
<b>Reactants</b>				
Calcite	50	44.7	44.9	40.9
Illite	50	49.7	49.0	0.0
Kaolinite	150	150.4	151.3	189.2
Quartz	700	700.1	700.2	737.9
Smectite-low-Fe-	50	49.4	47.9	0.0
<b>New Minerals</b>				
Dawsonite	N/A	0.0	0.0	22.3
Dolomite-dis	N/A	0.0	0.0	12.6
Goethite	N/A	0.0	0.1	1.8
Siderite	N/A	0.0	0.1	4.2
Clinoptil-Ca	N/A	0.4	1.5	0.0

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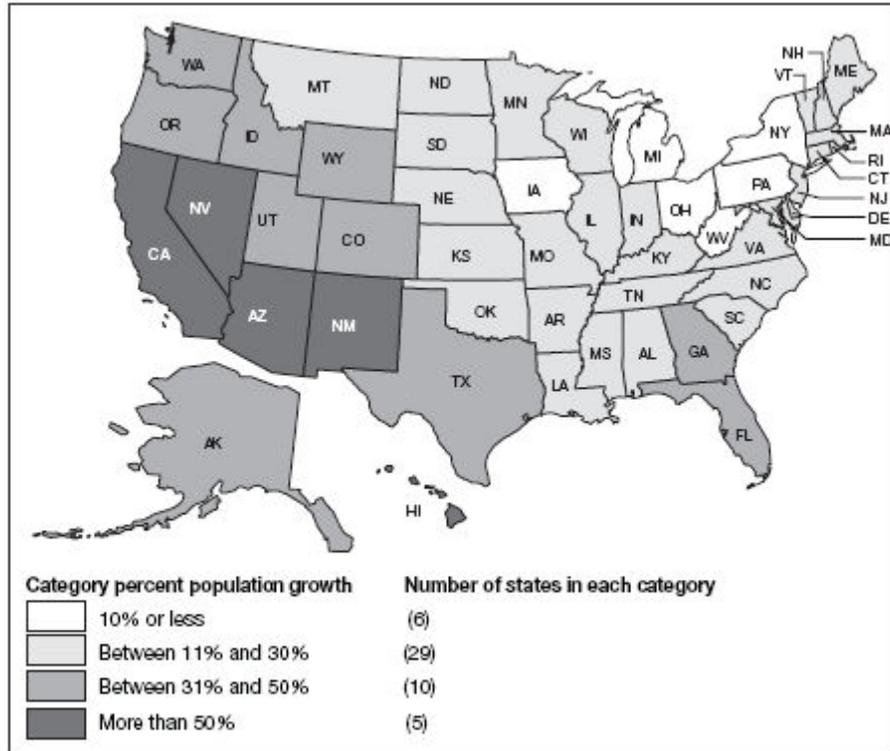
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## 2. WATER TREATMENT IMPACTS FROM UTILIZATION OF UNDERGROUND CO<sub>2</sub> SEQUESTRATION IN THE SAN JUAN BASIN FORMATION

Water supply availability throughout the United States may become a central issue when considering expanded power demands requiring already stressed supplies. A key to alleviating potential competing needs for water would be to further match the water sources with the type of demand. Power plants, for example, may have the resources required to treat saline water from deep saline formations thereby supplementing their demands on other water resources. Population growth, drought, power generating technologies, CO<sub>2</sub> capture systems and water desalination technologies may all be very region-specific, however, the confluence of these factors will determine the relative water stress due to water supply and demand imbalances.

### *Population Growth – New Mexico*

In a 2003 report by the General Accounting Office (GAO) report concerning water supplies and availability, New Mexico anticipates an increase in population by at least 50% by the year 2025. Increases in population will lead to increased pressure on water resources both directly and indirectly (e.g., increased power plant water withdrawal and consumption). Figure 2-1 illustrates population growth estimates by state.

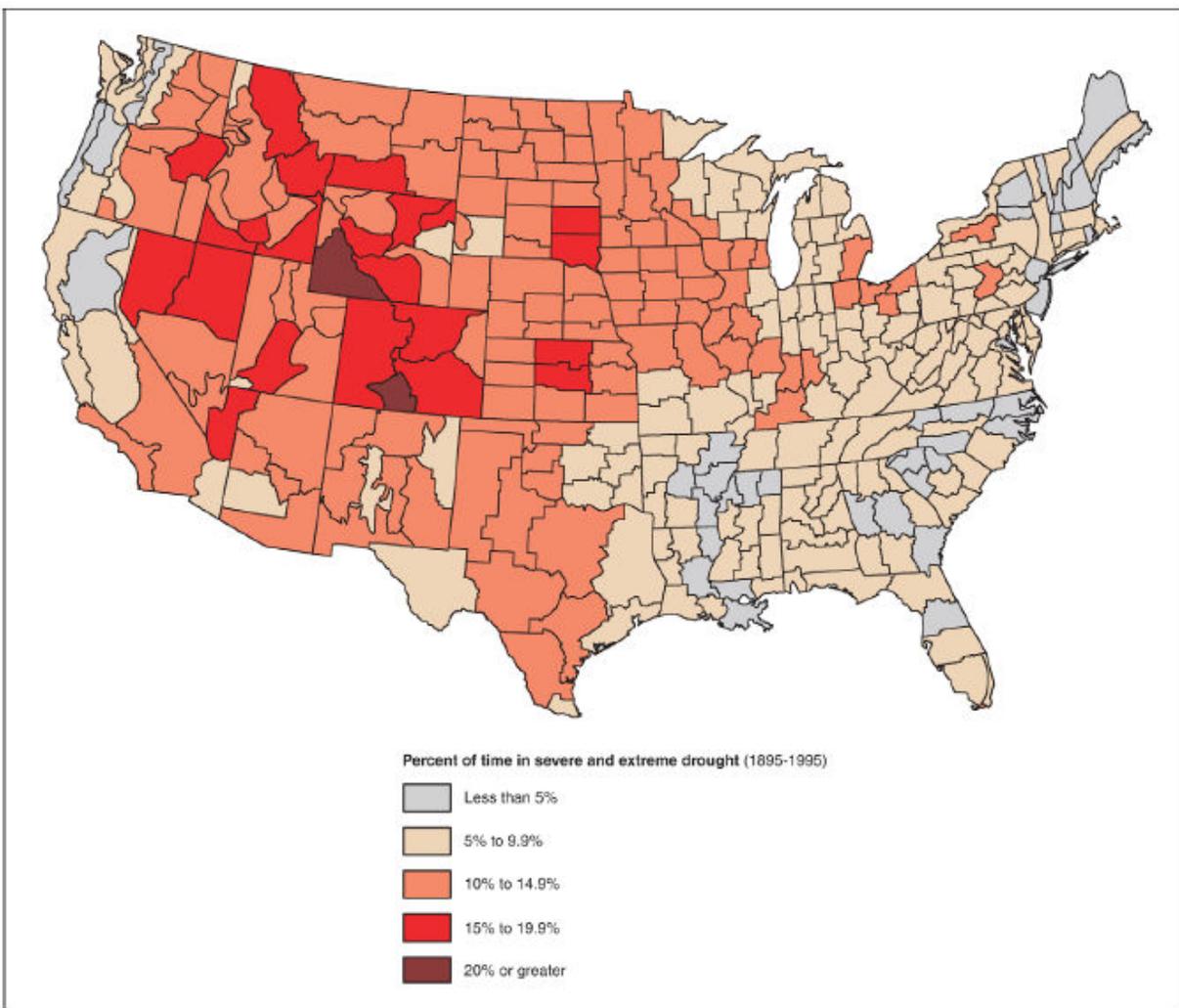


Source: U.S. Census Bureau.

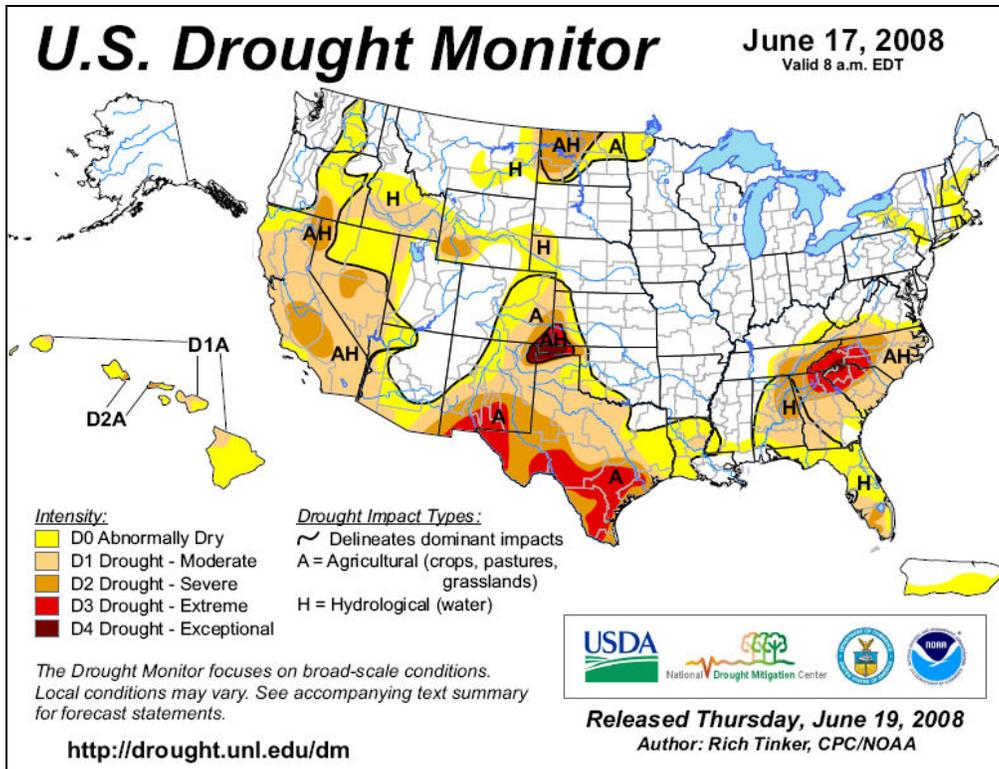
**Figure 2-1: 2003 GAO Population Growth Estimate (1995 - 2025).**  
(Adapted from the GAO, 2003).

## Drought

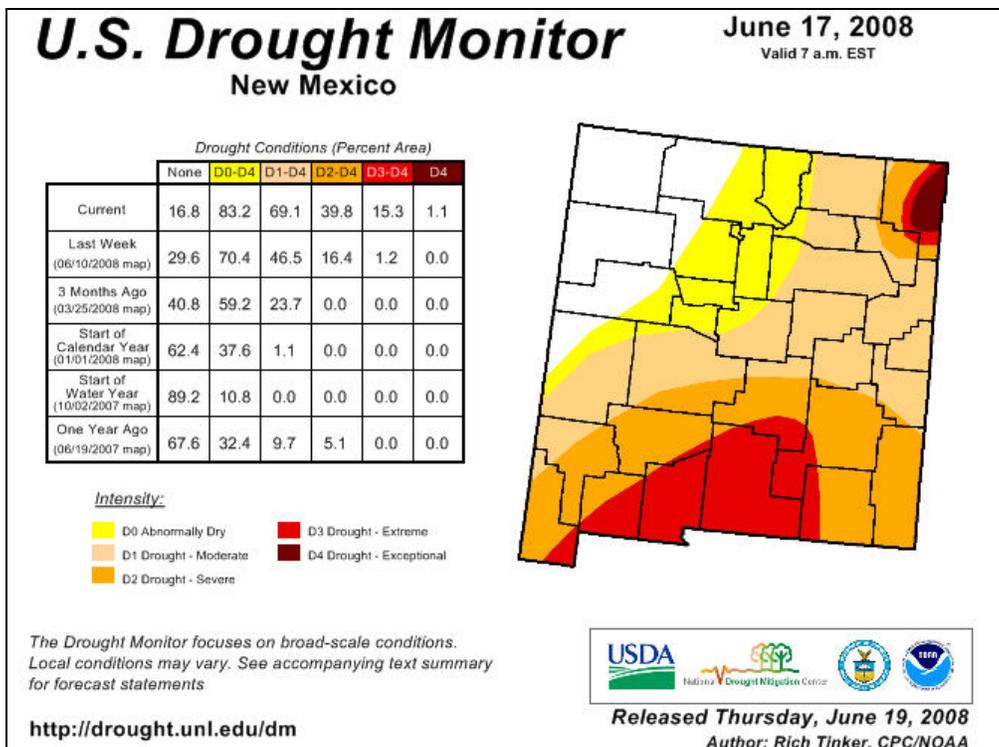
Much of the desert southwest has experienced drought in recent years. In a recent GAO report (GAO, 2003), 36 states (out of 47 states) reported that they anticipate water shortages under normal conditions in the next 10 years. In a drought, the number increases to 46. California, New Mexico, and Michigan did not participate in the 2003 study. As annual precipitation decreases, there is less water available in streams, rivers, lakes, and other surface facilities. Figure 2-2 shows the percentage of time in severe drought, and the current national and New Mexico drought status are shown in Figures 2-3 and 2-4. Drought mitigation may force power plants (and other surface water consumers) to consider non-fresh water, as this may be the only way to grow.



**Figure 2-2: Percent Time in Severe and Extreme Drought Nationwide (1895 - 1995).**  
(Adapted from the GAO, 2003).



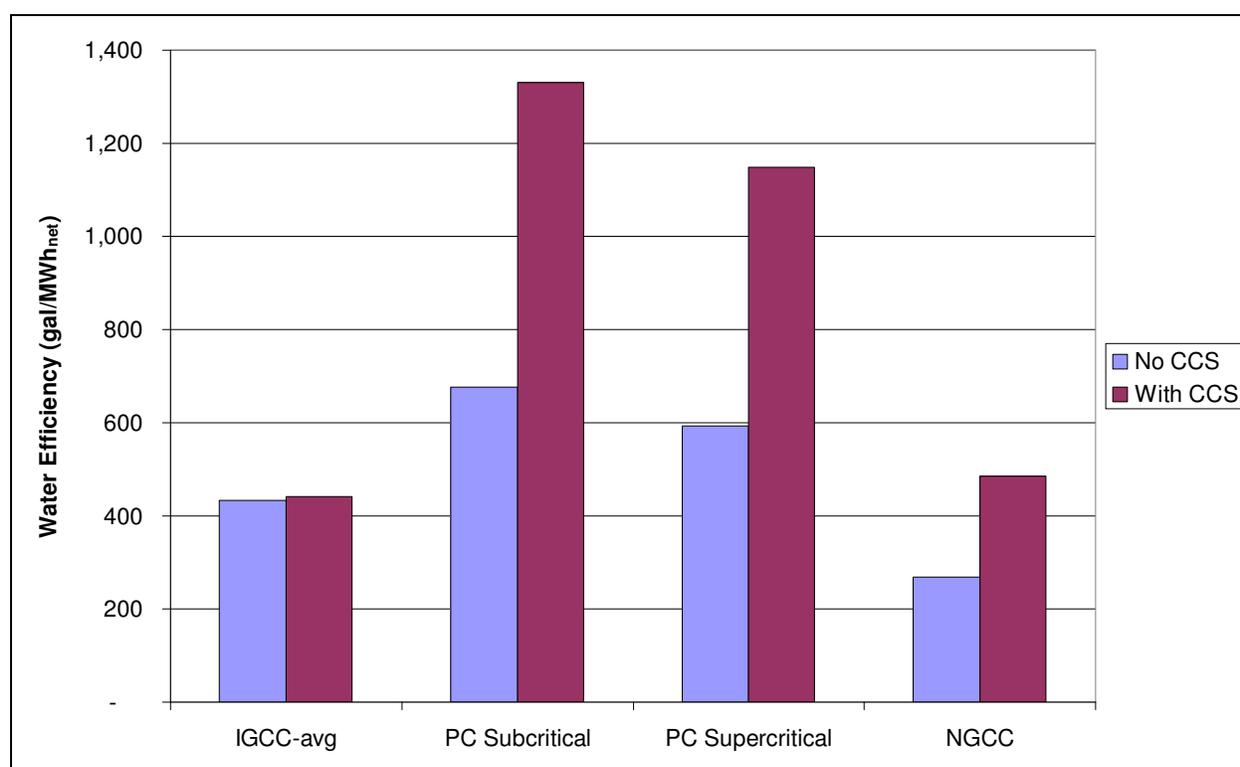
**Figure 2-3: U.S. Drought Outlook, June 17, 2008.**  
(Adapted from the NWS, 2008)



**Figure 2-4: New Mexico Drought Status, June 17, 2008.**  
(Adapted from the NWS, 2008)

## **Freshwater Needs for Thermoelectric Power Plants and Carbon Capture Technology**

As the demand for electricity increases, water consumption by thermoelectric power plants will likely increase. Thermoelectric power plants utilize water for cooling steam and account for 39% of the freshwater withdrawals and 2.5% of the freshwater consumption in the US (USGS 2004; 1998). Water withdrawal and consumption for new and existing power plants depends on the type of process used to generate electricity. Figure 2-5 is adapted from the 2007 DOE/NETL report and compares the relative water intensity of new pulverized coal (PC) and integrated gasification combined cycle (IGCC) plants with and without carbon sequestration technology installed.



**Figure 2-5: Relative Water Usage of new PC and IGCC Plants.**

(Carbon Capture and Sequestration (CCS); Integrated Gasification Combined Cycle (IGCC); Pulverized Coal (PC); Natural Gas Combined Cycle (NGCC); Adapted from DOE/NETL, 2007a).

Carbon capture technologies and their associated energy and water streams were analyzed in a recent DOE/NETL report (2007a). For pulverized coal subcritical power plants, the CO<sub>2</sub> capture system is assumed to be an amine absorber, which has a substantial, mostly indirect, water demand. In this report, water recycle is considered as part of the analysis. A summary of the findings from the 2007 NETL report on carbon capture is shown in Table 2-1.

**Table 2-1: Summary of NETL Report on Carbon Capture Technology Effects on Subcritical PC Power Plant**

		PC subcritical	PC subcritical + CCS	% Difference
Raw water consumption	gpm	6,212	12,187	96%
CO <sub>2</sub> emissions	lb/yr	1,038,110	152,975	-85%
Plant Cost	\$/kw	1,549	2,895	87%
Plant Efficiency	%	36.8	24.9	-32%

The SJGS is located in the study area called Western Electricity Coordinating Council/Rocky Mountains (WECC/RM) and encompasses Arizona, New Mexico, and southern Nevada. The WECC/RM thermoelectric capacity is anticipated to increase by nearly 50% and coal-fired generation capacity by nearly 100% (DOE/NETL, 2007a). This increase in coal-fired generation will require an increase in water withdrawal and consumption; non-fresh water sources will likely play a role in facilitating this growth.

### ***Summary of SJGS Water Consumption & Non-Fresh Water Applicability***

The total net summer electrical capacity in the state of New Mexico is 7,102 MW (EIA, 2008). The SJGS's total generating capacity of 1,848 MW is approximately 25% of this total. The SJGS consumes 22,400 acre-ft/year, primarily for its cooling towers (EPRI, 2006). The SJGS reuses its water many times prior to sending water to its evaporation ponds. The New Mexico-based utility company PNM anticipates its electrical demand increasing by 50-75 MW per year for the next ten years. If current design practices are followed, this would require an additional 600-9300 acre-ft/year of fresh water. PNM states that it plans to decrease its water intensity (water consumed per MW of power produced) by increasing its electrical generation capacity without increasing its water consumption above current rates where possible (PNM, 2008).

Cooling towers account for the majority of the SJGS water consumption (90%). The water source is the San Juan River, which like other surface waters, is low in TDS. The cooling towers operate at approximately 4-10 cycles of concentration, meaning water is recirculated until the concentration increases 4-10 times the original value until it is "blown down." This "blow down" water is drained from the cooling tower system while fresh water is added to maintain a constant level of TDS in the system. The blow down water is treated (distilled by brine concentrators) and reused throughout the SJGS plant and is described further later.

Expansion at the SJGS (and other power plants) will require additional water if wet cooling towers are to be used. Non-fresh water (e.g. brackish water or produced water) will require desalination prior to use, which could increase the amount of flow to evaporation ponds. Dry cooling towers could be employed, but there is an energy penalty as well as some potential operational concerns.

Another potential solution would be to find a technology that could utilize the waste heat currently sent to the condenser system or in the flue gas for desalination or other process use.

This could allow for an alternative water source high in TDS to be utilized economically, as well as help in the energy penalty associated with carbon sequestration.

### **Cooling Tower Water Chemistry Recommendations**

Cooling tower water chemistry is an important factor in power plant design. There are site specific limits based on the metallurgy of the piping system, materials of construction of the cooling tower itself, and regulations on the waste water. General recommendations from EPRI and CTI are listed in Table 2-2. Cooling towers that utilize surface waters and/or low TDS well waters can easily meet the requirements and operate efficiently (i.e., conserve water). However, many alternative sources of water (brackish, produced water, waste water) will have elevated levels of chloride and other problematic constituents such 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 O&M costs, but they offer the possibility of expansion and increased public acceptance in an age where every drop of water counts.

**Table 2-2: Water Quality Recommendations, Various Sources.**

Parameter	Units	EPRI (1982)	EPRI (1998)	CTI (2004)
Ca	mg/L <sub>(CaCO<sub>3</sub>)</sub>	900	No Information <sup>(4)</sup>	< 800
Ca x SO <sub>4</sub>	(mg/L) <sup>2</sup>	No Information	500,000 <sup>(5)</sup>	No Information
Mg x SiO <sub>2</sub>	mg/L <sub>(CaCO<sub>3</sub>)</sub> x mg/L <sub>(SiO<sub>2</sub>)</sub>	35,000 <sup>(1)</sup> 75,000 <sup>(2)</sup>	35,000 <sup>(5)</sup>	No Information
M Alkalinity	mg/L <sub>(CaCO<sub>3</sub>)</sub>	30-50 <sup>(1)</sup> 200-250 <sup>(2)</sup>	No Information <sup>(4)</sup>	No Information
Cl	mg/L	No Information	No Information	<750 <sup>(9)</sup> <1,500 <sup>(10)</sup>
SO <sub>4</sub>	mg/L	No Information	No Information <sup>(4)</sup>	<70 <sup>(11)</sup> <5,000 <sup>(12)</sup>
SiO <sub>2</sub>	mg/L	150	150 <sup>(5)</sup>	150
PO <sub>4</sub>	mg/L	<5 <sup>(3)</sup>	No Information <sup>(4)</sup>	No Information
Fe (total)	mg/L	No Information	<0.5 <sup>(5)</sup>	<3
Mn	mg/L	No Information	<0.5	<0.1
Cu	mg/L	No Information	<0.1	No Information
Al	mg/L	No Information	<1	No Information
S	mg/L	No Information	5	No Information
NH <sub>3</sub>	mg/L	No Information	<2 <sup>(6)</sup>	<50 <sup>(6)</sup>
pH		6.8-7.2 <sup>(1)</sup> 7.8-8.4 <sup>(2)</sup>	No Information <sup>(4)</sup>	6.5-9.0
TDS	mg/L	70,000	No Information	5,000 <sup>(13)</sup>
TSS	mg/L	No Information	<100 <sup>(7)</sup> <300 <sup>(8)</sup>	<25 <sup>(7)</sup>
BOD	mg/L	No Information	No Information	No Information
COD	mg/L	No Information	No Information	No Information
LSI		No Information	<0	No Information
RSI		No Information	>6	No Information
PSI		No Information	>6	No Information

**Notes:**

- <sup>(1)</sup> Without scale inhibitor
- <sup>(2)</sup> With scale inhibitor
- <sup>(3)</sup> No recommendation given, due to insufficient data
- <sup>(4)</sup> EPRI recommends a computer calculation for this parameter
- <sup>(5)</sup> Conservative value - EPRI recommends a computer calculation for this parameter
- <sup>(6)</sup> Applies only if copper is present in metallurgy
- <sup>(7)</sup> Applies if film fill installed in cooling tower
- <sup>(8)</sup> Applies if open fill installed in cooling tower
- <sup>(9)</sup> Applies if metallurgy is galvanized steel
- <sup>(10)</sup> Applies if metallurgy is series 300 stainless steel
- <sup>(11)</sup> Applies if > 800 mg/L (as CaCO<sub>3</sub>) of calcium
- <sup>(12)</sup> Applies if < 800 mg/L (as CaCO<sub>3</sub>) of calcium
- <sup>(13)</sup> Limit is for thermal performance

## SJGS Produced Water Study

The water treatment for cooling water calculations used in the model in this study are based on a 2006 NETL/EPRI cost-benefit analysis by Zammit and DiFilippo (2004), USBR desalination cost estimations (USBR, 2003), and standard engineering calculations (McCabe et al., 1993). A 2006 NETL/EPRI research effort looked at the potential for utilizing produced water from the oil and gas industry as a raw water source for the SJGS. This study compiled a detailed water balance (see Table 2-3 and Figure 2-5). The major water user at the SJGS is the cooling towers (90% of overall consumption). Other major equipment that consumes fresh water includes the ash system, limestone preparation system, and plant service water.

**Table 2-3: SJGS Simplified Water Balance.**

(Adapted from Zammit and DiFilippo, 2004)

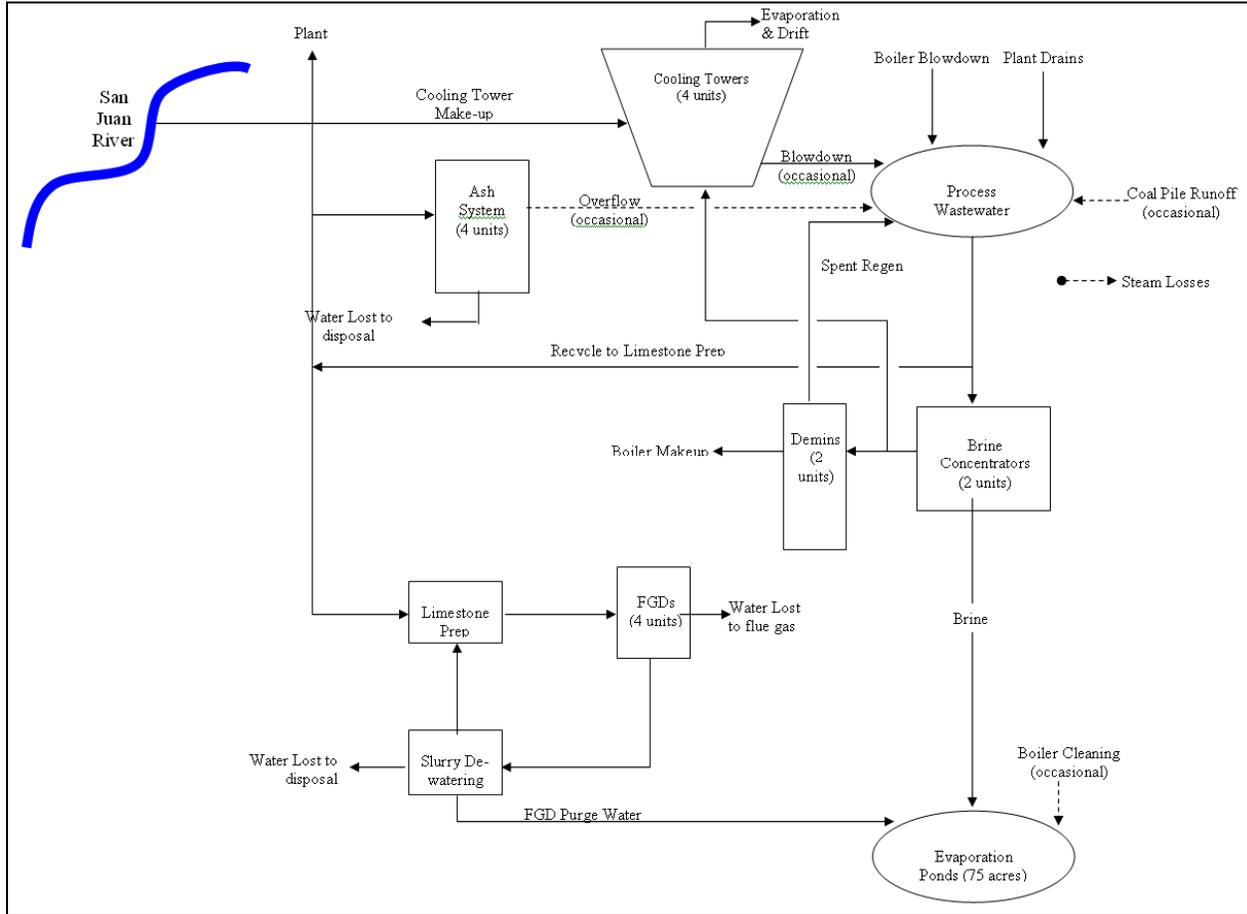
Description	Type	Flow Rate (gpm)
Total Plant Feed	FW	13,890
Cooling Tower Makeup	FW	12,480
Ash System Makeup	FW	100
Limestone Prep Fresh Makeup	FW	1,210
Plant Service water	FW	100
BC Distillate to CT	TRW	165
BC Distillate to Demineralizers	TRW	620
CT Evaporation & Drift	Lost	11,640
Boiler Feed water	TRW	620
Total Unusable Waste Water	WW	115
Total Recycle Streams	RW	6,530
Total Plant Losses (excl. CT evaporation & drift)	Lost	2,130

Much of the equipment currently uses recycled water that is either untreated recycled water (limestone preparation system) or treated waste water (boilers, cooling towers). The treated waste water is supplied by brine concentrators (BC) which distill water from various sources to a low TDS level. Each of these sources has water quality constraints as summarized in Table 2-4.

**Table 2-4: SJGS Water Quality Limits.**

(Adapted from Zammit and DiFilippo, 2004)

Process Area	Water Quality Constraint	Notes	
Cooling Towers	Ca	1,600 mg/L <sub>(CaCO<sub>3</sub>)</sub>	Circulating Water
	SiO <sub>2</sub>	150 mg/L	Circulating Water
	Cl	1,000 mg/L	Circulating Water
Absorbers	Cl	5,000 mg/L	Purge Water
Ash System	TDS	2,000 mg/L	Sluice Water TDS after pH adjustment
Brine Concentrators	B	<1 mg/L	BC feedwater
	Cl	9,000 mg/L 200,000-250,000 mg/L	BC feedwater BC brine



**Figure 2-6: SJGS Simplified Water Flow Diagram.**  
(Adapted from Zammit and DiFilippo, 2004).

The 2006 NETL/EPRI effort and Zammit and DiFilippo (2004) study focused on 1,316 gallons per minute (gpm) of produced water that was within 28.5 miles combined with available flue gas desulfurizer (FGD) purge water. This produced water is from the Fruitland formation and is associated with existing oil and gas operations. After desalination and re-capture by the brine concentrators, 1,255 gpm of treated water is available for use by the cooling towers. This would account for approximately 10% of the cooling tower feed (9% of total water consumption). Table 2-5 summarizes the San Juan river, raw produced water, and blend water chemistry from the 2004 EPRI report. Although there is an increased level of chlorides, this should not affect the cooling towers much, since this stream is such a small portion of the overall feed. Even if fed undiluted to a cooling tower, 7-8 cycles of concentration could be maintained (as compared to the current 10 cycles).

The 2006 NETL/EPRI and Zammit and DiFilippo (2004) cost-benefit analysis determined that the best treatment approach (most cost effective) for utilization of produced water was High Efficiency Reverse Osmosis and refurbishing two of the existing brine concentrators (not currently used) to eliminate the potential of additional water sent to the SJGS evaporation ponds.

The study found that produced water could not be used in a cost effective manner by the cooling towers without significant treatment. This is due primarily to the need for additional evaporation ponds as well as existing water quality restrictions for the cooling towers and other equipment.

The High Efficiency Reverse Osmosis (HERO) process is designed to pre-treat the produced water, which will remove most of the scale-forming minerals (e.g., calcium) and other constituents contributing to a higher TDS level (e.g., chloride). This process would operate at 83% efficiency (i.e., 0.83 gallons of treated water for each 1 gallon of produced water fed to the HERO process). The concentrate stream from the HERO process would be sent to the refurbished brine concentrator (BC3), which would yield a distillate stream and a brine stream. The refurbished brine concentrator would recover 73% of the HERO system’s reject stream, which would be mixed with the HERO system’s permeate and fed directly to the SJGS cooling towers. The concentrate stream is sent to the existing evaporation ponds. This study compared two different water sources, which are shown in Table 2-5:

- Produced water only, which was a mixture of several sources located within 28.5 miles of the SJGS. This is Option 5 in Zammit and DiFilippo (2004).
- Produced water + Purge water blend. Purge water is from the flue gas desulfurizers (FGDs). This is Option 10 in Zammit and DiFilippo (2004).

**Table 2-5: Summary of Zammit and DiFilippo (2004) Water Chemistry.**

	ppm or mg/kg		ppm or mg/kg					
Formation	TDS	pH	Na	Ca	Mg	Cl	SO4	HCO3
PW-EPRI Report	13,461	7.84	4,491	79	30.5	5,043	198	3,619
Blend (PW/PW)-EPRI Report	14,679	7.84	4,362	110	344	4,962	1,550	3,351
Desalinated PW/PW-EPRI Report	170	8.63	30	0	0	130	11.4	1.1
San Juan River	348	8	29	54	11	22	107	125

Option 10 in Zammit and DiFilippo (2004) was determined to be the most feasible, in terms of economics, and in terms of minimizing additional evaporation pond construction. Capital and annual operating costs were estimated to be \$14.1 million and \$2.98 million, respectively. This option would recover 1,255 gpm (approximately 2,000 AF/yr) and would require no additional evaporative ponds. This results in a moderate treatment cost of \$4.52 per 1,000 gallons of recovered water. In addition, there would need to be \$5.24 million in capital costs and \$470,000 in operational costs to capture, treat, and transport the produced water to the SJGS (Deliverable 6 in the NETL/EPRI (2006) and Zammit and DiFilippo (2004) efforts).

### **Utilization of Brackish Formation Water for CO<sub>2</sub> Sequestration Activities**

There is some debate over how CO<sub>2</sub> injection will be regulated by state and/or federal authorities. Current regulations in the Underground Injection Control (UIC) program are set up to protect drinking water sources, which are defined as anything with a TDS level below 10,000 mg/L. Oil and gas produced water disposal falls into UIC Class II wells (EPA, 2009). It is

recognized the model being developed initially has lower TDS, that it is recognized that for saline formations, waters with TDS less than 10,000 ppm would not likely be used for sequestration in saline formations. But that the formation was used in this initial case study to provide the opportunity to start building the model based on a formation for which a large amount of data was already available, and that future iterations of the model looking at saline formations are expected to focus on waters with TDS greater than 10,000 ppm.

### New Water Formation Chemistry for Cooling Tower Make-up

Similar to the work of Zammit and DiFilippo (2004), none of the available brackish waters could be used economically in their raw state for cooling tower make-up. This is primarily due to the type of use – the cooling tower system requires chlorides to be below 1,000 mg/L. Even if one were to replace the cooling system with one that can handle higher chloride waters, there would be a significant increase in the amount of evaporation ponds or other process equipment to maintain a zero liquid discharge facility.

Potential deep saline formations are summarized in Table 1-1 (formations studied using REACT) and Table 2-6 (formations with TDS above 10,000 mg/L). Utilizing the same treatment process as in the work of Zammit and DiFilippo (2004) (high efficiency reverse osmosis combined with brine concentrator retrofits) for each of these saline formation sources would yield similar results. One can assume that lower TDS waters will yield lower overall desalination costs. Other significant costs are in the gathering and transport of formation water to the desalination plant (assumed to be at the power plant). It is important to note that a more complete water analysis would be required to perform a proper design. Future studies will look at formations with a TDS level greater than 10,000 mg/L TDS.

**Table 2-6: Comparison of High TDS Formation Waters.**

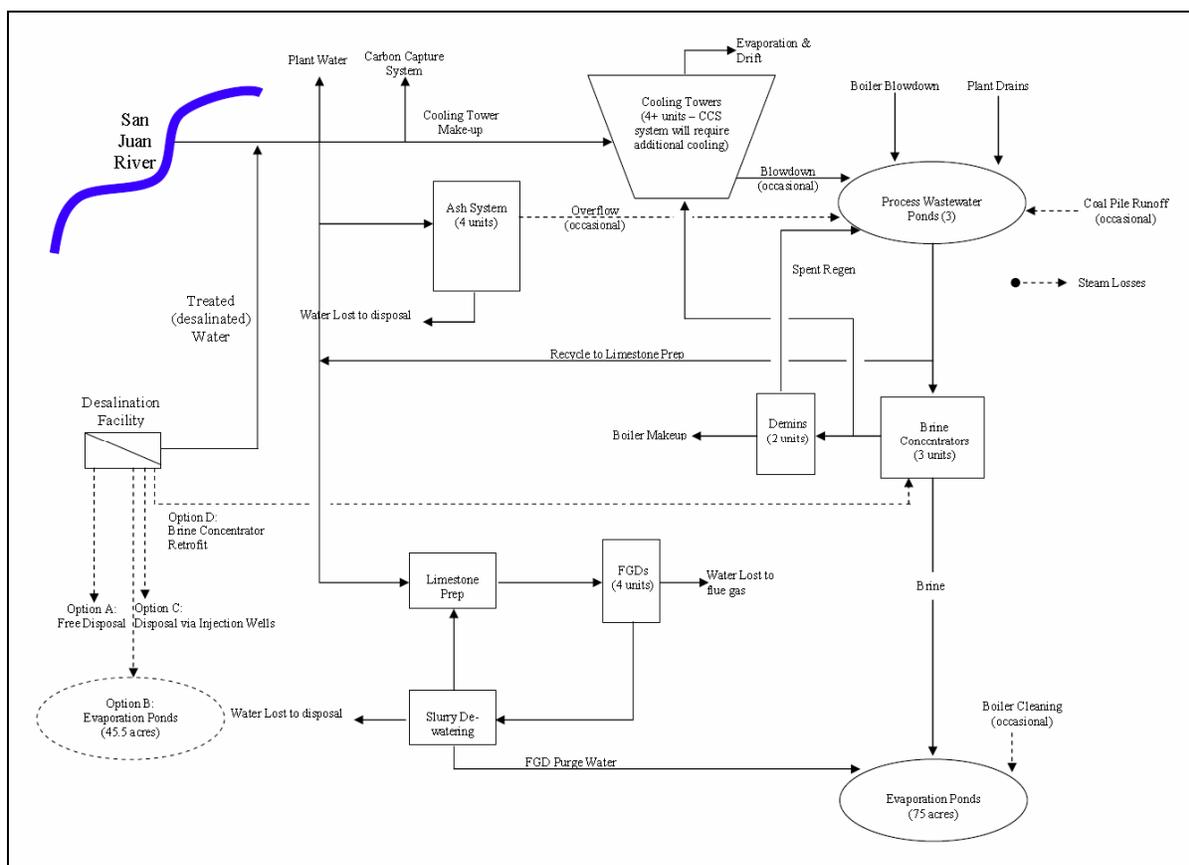
Formation	Radial distance from SJ plant miles	TDS ppm or mg/kg	pH	Na ppm or mg/kg	Ca ppm or mg/kg	Mg ppm or mg/kg	Cl ppm or mg/kg	SO4 ppm or mg/kg	HCO3 ppm or mg/kg
Dakota	33.8	11,464	7.7	4,123	155	43	6,400	10.7	732
Dakota	25.8	12,040	7.4	4,504	259	18	6,600	12.1	647
Dakota	21	14,791	7.9	4,964	167	30	4,182	4,178	1,270
Dakota	30.3	15,166	8.1	5,647	126	20	7,700	13.9	1,659
Fruitland	32.5	12,191	8.5	3,968	5	54	2,740	6.8	5,417
Fruitland	32.5	13,602	8.4	4,050	44	27	1,460	5.6	8,015
Fruitland	32.5	13,736	8.2	3,926	70	13	1,450	5.5	8,272
Fruitland	31.2	18,587	8.6	5,798	48	12	9,22	6.8	11,800
GALLUP - SS/ in Mancos	2.6	13,240	7.9	4,817	71	65	6,250	11.6	2,025
Hermosa/ Paradox	11.5	10,164	8	2,802	368	49	425	5,800	720
Hermosa/ Paradox	10.7	12,282	8	5,205	310	93	3,333	13.8	3,327

## Detailed Summary of Desalination Options Studies for the Model

Once the potential deep saline formations had been studied for their geochemical properties and water quality restrictions were known, several desalination options were studied using a simple spreadsheet analysis. These options all utilized reverse osmosis for desalination and varied in the mode of waste water disposal. The options studied were:

- Option A Desalination & gathering Equipment only; no concentrate disposal
- Option B Desalination & gathering Equipment only; 59.5 acre evaporation ponds for concentrate disposal
- Option C Desalination & gathering Equipment only; 3000 ft injection pipeline & well for concentrate disposal
- Option D Desalination & gathering Equipment - HERO+Brine concentrator retrofit (Zammit and DiFilippo (2004) report numbers are based on higher TDS)

These options are shown schematically in Figure 2-7. Each of the options studied required calculations for the capital and operational and maintenance (O&M) costs. Most of the calculations are based on the USBR Desalting Handbook (USBR, 2003). Each of the important estimations is shown in detail in Appendix 1 and is summarized in Table 2-7. Similar to the Zammit and DiFilippo (2004) report, Option D was determined the best option for the SJGS.



**Figure 2-7: SJGS Simplified Water Flow Diagram.**  
(Adapted from Zammit and DiFilippo, 2004).

**Table 2-7: Summary of Desalination Calculations and Assumptions.**

	<b>Base Case</b>	<b>Value</b>
<b>Water TDS (mg/L)</b>	Used Morrison formation	6,000
<b>Design Flow rate (gpm)</b>	based on 24/7 pumping of brackish formation, and the percentage of CO <sub>2</sub> captured	1,807
<b>Design Flow rate (MGD)</b>	Used 2.0 MGD desalination output (treated water)	
<b>Design Annual flow (Mgal/yr)</b>	based on 0.85 plant capacity factor (USBR recommendation)	400
<b>Electrical Cost (\$/kwh)</b>		0.1
<b>Pipeline distance from brackish well to desal plant (mi)</b>	based on radial distance, Morrison formation	3
<b>Well Depth (ft)</b>	based on Morrison formation	4,725
<b>Capital Costs:</b>		
Pump & Pipe - Produced Water Gathering Capital	Used USBR Desalting Handbook, Figure 9-18	\$2,000/ft
Piping from gathering station to desal plant	Used USBR Desalting Handbook, Figure 9-11	\$126,810/mi
Concentrate Disposal pipeline & well	Used USBR Desalting Handbook, Figure 9-11 & 9-13	
Evaporation ponds	Used USBR Desalting Handbook, Figure 9-12	
Desalination Total Construction Cost	Used USBR Desalting Handbook, Figure 9-7	\$2000/mg/L TDS for options A-C Zammit and DiFilippo (2004) value for option D
<b>O&amp;M</b>		
Labor (for 2 MGD)	Used USBR Desalting Handbook, Figure 9-37	
Electrical-BWRO (for 6,000 mg/L TDS, 2 MGD)	Used USBR Desalting Handbook, Figures 7-8 & 9-45	
Electrical-GW pumping (for 1807 gpm/2 MGD)	Used equations to estimate pump power; See Appendix X	
Membrane Replacement	Used USBR Desalting Handbook, BWRO	\$0.08/1000 gal plant capacity
Chemicals (used surface water)	Used USBR Desalting Handbook, Figure 9-41	
Other Maintenance	Used USBR Desalting Handbook	1.5% of capital

The final cost for the base case is shown in Table 2-8. This is for a 2.0 MGD desalination facility and compares each of the options considered. The total cost of treatment (including desalination facility and brackish water gathering) is \$5.32 per 1000 gallons of treated water; the cost of desalination alone is \$2.72 per 1000 gallons of treated water. This desalination cost is inline with both the Zammit and DiFilippo (2004) study, as well as others (Miller, 2003; USBR, 2003) who have studied the cost of desalination.

**Table 2-8: Summary of Desalination Costs – Base Case.**

	Option A	Option B	Option C	Option D
Total Cost of Treatment (incl. concentrate disposal, GW pumping)	BWRO-no conc disposal	BWRO-evap ponds	BWRO-injection well	HERO+BC retrofit
	\$/1000 gal	\$/1000 gal	\$/1000 gal	\$/1000 gal
Annualized Total Capital	\$ 2.90	\$ 5.05	\$ 3.25	\$ 2.59
Annual O&M	\$ 2.16	\$ 2.19	\$ 2.17	\$ 2.73
Electrical	\$ 0.27	\$ 0.27	\$ 0.27	
Membrane Replacement	\$ 0.0003	\$ 0.0003	\$ 0.0003	
Other	\$ 0.54	\$ 0.54	\$ 0.54	
<b>Total Cost (O&amp;M+cap)</b>	<b>\$ 5.06</b>	<b>\$ 7.24</b>	<b>\$ 5.39</b>	<b>\$ 5.32</b>
Cost of Desalination only - includes only equipment & O&M for desalination (i.e. no ponds, no GW pumping)	Option A	Option B	Option C	Option D
	BWRO-no conc disposal	BWRO-evap ponds	BWRO-injection well	HERO+BC retrofit
	\$/1000 gal	\$/1000 gal	\$/1000 gal	\$/1000 gal
Annualized Total Capital	\$ 1.59	\$ 1.59	\$ 1.59	\$ 1.28
Annual O&M	\$ 1.19	\$ 1.19	\$ 1.19	\$ 1.43
Electrical	\$ 0.27	\$ 0.27	\$ 0.27	\$ 0.86
Membrane Replacement	\$ 0.08	\$ 0.08	\$ 0.08	\$ -
Other	\$ 0.59	\$ 0.62	\$ 0.59	\$ 0.64
<b>Total Cost (O&amp;M+cap)</b>	<b>\$ 2.78</b>	<b>\$ 2.78</b>	<b>\$ 2.78</b>	<b>\$ 2.72</b>

### Mass/Heat Balance around SJGS

In thermoelectric plants, steam must be condensed, which uses energy. The energy is comprised of pumps, compressors, fans, etc. If this waste heat could be utilized in the plant for other operations such as in the brine concentrators or for new thermal desalination techniques, it would decrease the impact of installing CO<sub>2</sub> sequestration equipment.

NETL has studied the water loss and energy requirements for several types of power plants. The following characteristics were developed for steam that is sent to a condenser at a subcritical power plant. More detailed calculations and a determination of the potential use of waste heat will likely build on this information in future analyses.<sup>1</sup>

**Table 2-9: NETL Parameters – Waste Heat to Condenser (Sub Critical Power Plant).**

Pressure	130.9	psia
Temperature	692	F
Mass Flow	295,356	lb/hr
Enthalpy	1,373.75	btu/lb

<sup>1</sup> Erik Shuster of the National Energy Technology Laboratory provided guidance on thermoelectric power plant waste heat calculations. Follow on phases of this study will likely draw from this initial information.

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### **3. REGIONAL ASSESSMENT FRAMEWORK: SYSTEMS ANALYSIS CAPABILITY AND FRAMEWORK**

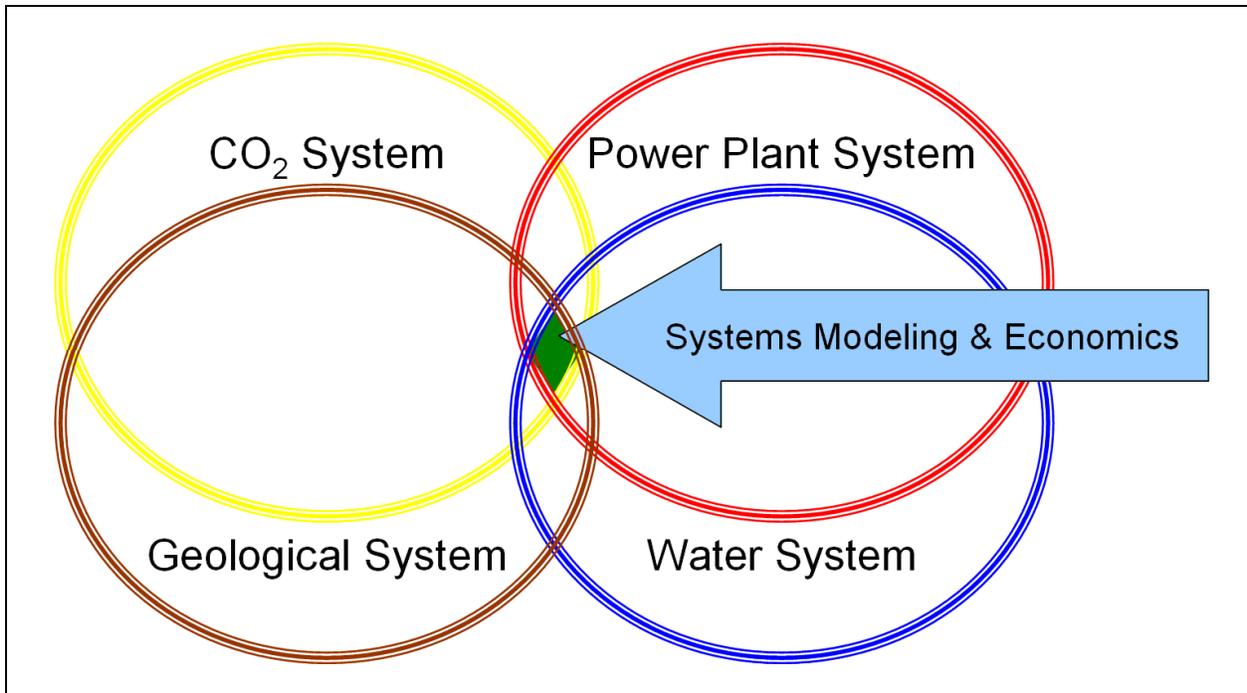
The goal of the regional assessment is to highlight the high-level issues with associating an existing power plant with both carbon sequestration and using brackish water from a deep saline formation to supplement its water demands. This assessment builds off of the first two chapters, and should be considered a synthesis of the geochemical/geological assessment and that from the water treatment analysis.

The overarching analysis began by first assessing geologic carbon sequestration into a deep saline formation from a power plant, combined with a water utilization system to exploit the potential brackish water source provided by the saline formation. Conceptually, this system is relatively straightforward. However, beginning with the concept and moving first to a rudimentary analysis, and then on to an increasingly detailed study hinges on several key engineering, geological and finally economic challenges to more accurately assess this system. A dynamic simulation model was developed to both illustrate the stocks and flows associated with this system (e.g., electricity production, CO<sub>2</sub> annual flows, water treatment costs and flows, etc.) and to begin calculating the costs for each of the components.<sup>2</sup> Using this software allows interested parties the ability to perform ‘what if’ scenario analysis in real time. For example, the model can address the question, ‘What if the level of CO<sub>2</sub> capture increases from 50% to 90%? What will the electricity costs look like?’ Similar scenario questions can be addressed for different power plant configurations, geological formations used for CO<sub>2</sub> sequestration, and brackish water pumping treatment technologies.

A schematic of the underlying analytical framework was developed to illustrate the study’s components. Figure 3-1 illustrates the overall assessment framework where the dynamic systems model also adopts the color coding for transparency in the variables throughout the development of the subsequent model (e.g., power systems are red, CO<sub>2</sub> systems are yellow, geological systems are brown, and water systems are blue).

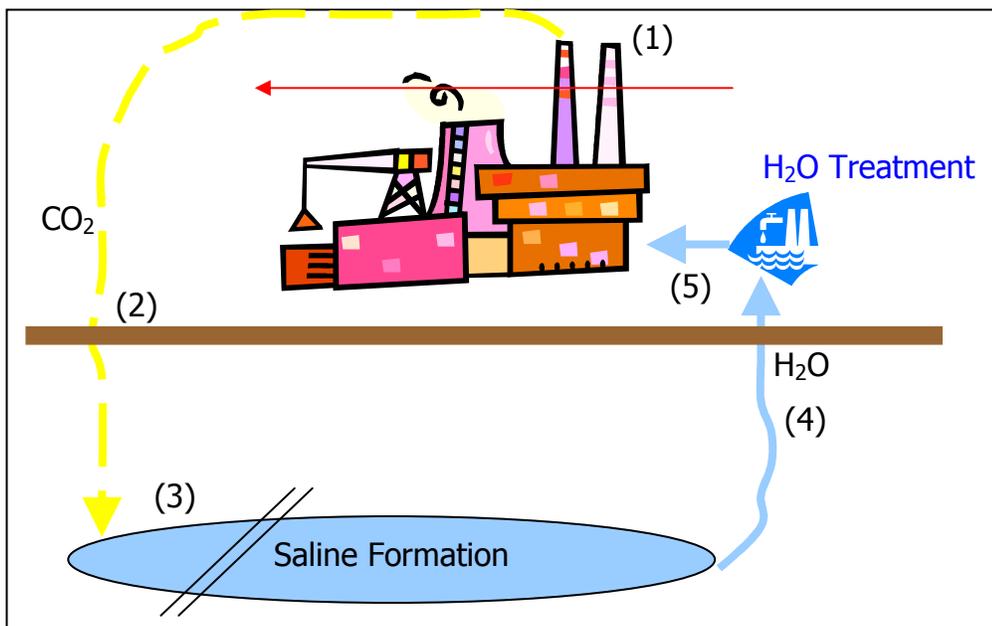
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<sup>2</sup> The dynamic systems software Powersim Studio 7 was used to integrate and analyze the data.



**Figure 3-1: Topical Overlap of the Energy-Economic Modeling Assessment Framework.**

Figure 3-2 illustrates a more focused schematic of a power plant with a carbon capture and sequestration system associated with a deep saline formation. This ‘conceptual cycle schematic’ lays the foundation for the analysis, and continues to refine the characteristics and assumptions used for the power plant, carbon sequestration, geological system, and brackish water extraction and treatment systems.



**Figure 3-2: Conceptual Design of a Combined Power Plant with CO<sub>2</sub> Sequestration while Using Water from a Deep Saline Formation.**

Figure 3-2 illustrates each facet of the combined power/water/CO<sub>2</sub> sequestration/water treatment and use system using a number designation for general subsystems of the analysis. The following descriptions explain how the dynamic simulation model incorporates these components, and describes potential next steps to further refine the techno-economic model.

### Power Plant and CO<sub>2</sub> Sequestration

Section ‘(1)’ shown in Figure 3-2 details the power plant and carbon capture and sequestration systems. The study begins with the SJGS in Farmington, NM. This power plant is a coal-fired electricity generating station with four boilers associated with the generators representing a combined 1,848 MW of installed capacity. According to the eGRID database, each of the four boilers (and their respective cooling towers) consumes 0.02 cubic feet of water per kilowatt hour (kWh) per boiler (EPA, 2006). Scaling up to the full plant size, this represents a water consumption rate of around 0.52 gallons/kWh. Additionally, the percent capture level for CO<sub>2</sub> was developed from existing literature for the 0, 30, 50, 70, and 90% levels of capture for CO<sub>2</sub> (NETL, 2007)<sup>3</sup>. Table 3-1 further illustrates the performance, economic and CO<sub>2</sub> sequestration metrics associated with different levels of CO<sub>2</sub> capture.

**Table 3-1: Performance and Techno-economic metrics associated with capturing CO<sub>2</sub> for the test case model.**

Percent of CO <sub>2</sub> Captured →	0	30	50	70	90
Power Plant Rating, % Decrease from Base 1,848 MW	0	10.34	19.52	30.17	43.01
Additional costs of electricity (cents/kWh)	0	2.31	3.64	5.32	6.92
CO <sub>2</sub> Captured and Sequestered (million metric tons, MtC)	0	3.95	6.58	9.22	11.85

### Geophysical Formation Assumptions

Section ‘(2)’ shown in Figure 3-2 addresses the high-level geophysical aspects of sequestering CO<sub>2</sub> in a geological formation and the subsequent (assumed) volume of displaced water. The base case of the analysis uses the Morrison formation to illustrate the scale of the sequestration and potential for displaced water volumes. The Morrison formation, as described in the geochemical chapter of this report, may be a candidate to sequester CO<sub>2</sub> while at the same time serve as a source of non-traditional brackish waters for power plant cooling.

The analysis began by using the hydrostatic pressure assumption employed by the NatCarb database when calculating the volumes available within each formation to store CO<sub>2</sub>. For example, NatCarb builds from example conditions of 8,000 feet deep, 140° F, and 3,500 pounds per square inch (psi). Assuming a column of water 33 feet high gives a pressure of around one atmosphere (1 bar), this example indicates NatCarb works off of hydrostatic pressure for the well

<sup>3</sup> NETL, 2007. Summary metrics adapted from Table ES-1, “Summary of Technical and Economic Performance for Retrofitting a Pulverized Coal-Fired Plant.”

depth [(8,000 feet / 33 feet) \* 14.7 (psi/bar)] = 3,563 pounds per square inch (psi). The NatCarb example approximates the pressure to 3,500 psi, which corresponds to (3,500 (psi/bar) / 14.7 (psi)) = 238 bars. Using this assumption, the density of CO<sub>2</sub> given is 48.55 lbs mass per cubic foot. Therefore, one calculates the volume displacement relationship of sequestered CO<sub>2</sub> to H<sub>2</sub>O as: (1,000g/kg\*48.55 lbs / 2.2046 lbs/kg) / ((2.54<sup>3</sup>)\*12<sup>3</sup>) cm<sup>3</sup> per ft<sup>3</sup>) = 0.777 g (CO<sub>2</sub>) / cm<sup>3</sup> (H<sub>2</sub>O). Thus, for every one gram of CO<sub>2</sub> injected underground it displaces approximately (1 / 0.777) = 1.29 cm<sup>3</sup> of water. Assuming the temperature scales linearly with depth from near ambient (approximately 20 degrees Celsius) at the surface to the reference value of 60 degrees Celsius at 8,000 feet we can begin to develop a scaling of proportionality between the given CO<sub>2</sub> storage resource of a formation and the water that may be displaced based on depth.<sup>4</sup>

## CO<sub>2</sub> Sequestration and Brackish Water Volume Analysis

Section '(3)' shown in Figure 3-2 builds off of the geophysical properties of the potential for CO<sub>2</sub> to displace (or substitute) H<sub>2</sub>O within the formation. Based on the methodology developed in the geochemical and geophysical analysis, a regression analysis on the density of CO<sub>2</sub> at different pressures was adopted from a CO<sub>2</sub> density table in Clark, 1966. While the pressures involved with this test case framework lie within the supercritical range of the CO<sub>2</sub> density vapor curve analysis, two regression analyses were developed to account for the stylized break in the pressure to CO<sub>2</sub> density curve analysis; 25 – 100 bars, and then 150 – 400 bars. The regression equations allow the users of the dynamic simulation model to adjust the potential density of CO<sub>2</sub> based on the depth of the formation being considered.<sup>5</sup>

The representative depth for the initial formation location is 4,725 feet, where assuming hydrostatic pressure, this would equate to 321.43 bars. Using this result combined with a linear regression equation for the density of CO<sub>2</sub> under pressure and the water it may displace, the working framework calculates that approximately 317 gallons of water may be displaced for every metric ton of CO<sub>2</sub> sequestered under these types of conditions. However, number of gallons calculated may be highly condition and site specific such that it should be considered a starting point for a more detailed geophysical analysis, and ideally, field test to validate the reliability of this assessment and subsequent relationship over time.

## Brackish Water Extraction

Section '(4)' of the system's framework calculates the volumes of water displaced due to sequestering the CO<sub>2</sub>. Under the working assumptions to illustrate the methodology, the Morrison formation may have a theoretical yield of displaced waters on the order of 1.45 trillion gallons. This may represent on the order of 200+ years' worth of water supply for the SJGS at current rates of consumption. There are, however, substantial technical and economic hurdles that need to be overcome to utilize this water resource in addition to further refining of the assessment framework.

<sup>4</sup> Special thanks to Jim Krumhansl for his assistance with the working CO<sub>2</sub> to potential H<sub>2</sub>O displacement calculations.

<sup>5</sup> The equation for the 150 – 400 bars is: CO<sub>2</sub> density (g/cm<sup>3</sup>) = 0.486176 + (0.001081\*pressure in bars), whereas the equation for 25 – 100 bars is: CO<sub>2</sub> density (g/cm<sup>3</sup>) = -0.0505 + 0.003214\*pressure in bars).

## Water Treatment

Section ‘(5)’ completes the analytical framework by developing the cost to extract and treat brackish water for the SJGS. The base case analysis employs option D described in Table 2-8. Table 3-2 summarizes these 5 components and their respective working assumptions and results underlying the dynamic simulation model.

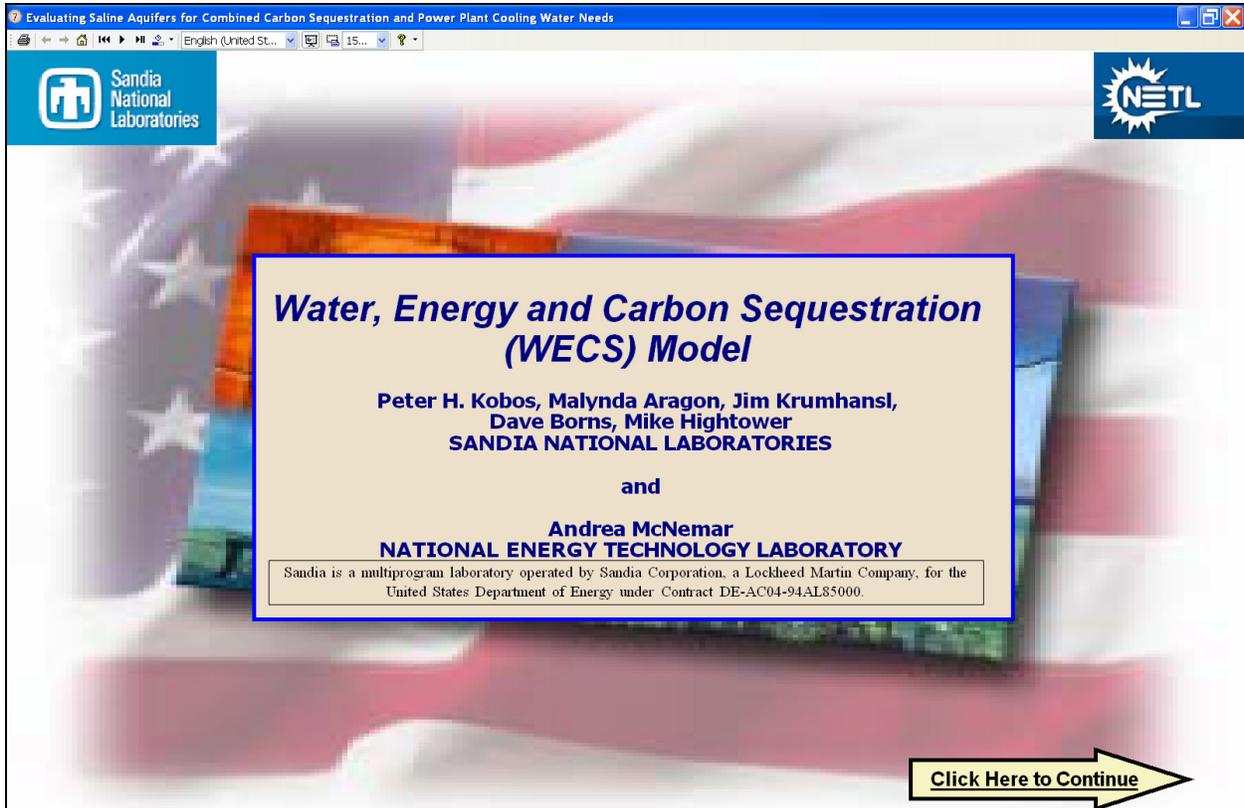
**Table 3-2: Test Case and Working Model Methodology.**

Section	Description	Assumption	Units	Notes
<b>1</b>	<b>Power Plant</b>	1848	MW	SJGS
	Capacity Factor	72	%	EPA, 2006 (eGRID)
	CO <sub>2</sub> Capture	50	%	Adjustable capture %
	CO <sub>2</sub> Emissions	14,512,417.5	tons/year	EPA, 2006 (eGRID)
	CO <sub>2</sub> Sequestered	6,582,722	metric tons/year	metric tons sequestered
<b>2</b>	<b>Saline Formation</b>	5000	mmt	Morrison Formation, CO <sub>2</sub> storage volume, NatCarb, 2007.
	Representative Depth	4725	feet	NatCarb, 2007
	Years' worth of CO <sub>2</sub> storage resource	760		volume / metric tons sequestered
<b>3</b>	<b>Saline Water displaced</b>	4,725 ft / 14.7 psi = 321.43	bar	hydrostatic pressure assumption/approximation, NatCarb, 2007.
	CO <sub>2</sub> displacing H <sub>2</sub> O	1/ (0.486175 + (0.001081*321.43)) = 1.20	Cubic centimeters of H <sub>2</sub> O per gram of CO <sub>2</sub>	Regression Equation based on Density of CO <sub>2</sub> vapor curve.
<b>4</b>	<b>H<sub>2</sub>O displaced and Demand</b>	625	Million gallons / year	625 Million gallons/year or 1.74 million gallons/day Potential water volume assuming 30% recovery
	H <sub>2</sub> O total potential extracted	475	Billion gallons total	Potential water volume assuming 30% recovery
	Power Plant cooling towers' H <sub>2</sub> O demand	6.4	Billion gallons / year	27.6 ft <sup>3</sup> /second, EPA, 2006 (eGRID); ~17.8 million gallons/day
	Years' worth of H <sub>2</sub> O supply	74 (760)	Years	475 billion gallons / 6.4 billion gallons/yr; (years meeting only 9.75% of the plant's 17.8 MGD water requirement rather than the full requirement).
<b>5</b>	<b>Desalination Costs – Base Case</b>	5.32	\$/ thousand gallons	Option D, HERO+BC option outlined in Table 2-8

Section ‘(5)’ in Figure 3-2 outlines the desalination technologies used in the base case for the model. These technologies, and their associated costs, are outlined in Table 2-8. The High Efficiency Reverse Osmosis system with a Brine Concentrator (HERO+BC) system was adopted

for the base case. The other technology and cost options for desalination can be introduced and analyzed in the model as well.

## ***The Water, Energy and Carbon Sequestration (WECS) Model Prototype***



**Figure 3-3: Prototype Front Screen of the Phase I Dynamic Simulation Model for the Water, Energy and Carbon Sequestration Integrated Modeling Assessment.**

Figure 3-4 illustrates the prototype model's interactive interface. This interface allows users to adjust select attributes of the power plant, CO<sub>2</sub> capture, geological storage, water demand and electricity cost systems. Changing these attributes allows for sensitivity analyses across the four respective systems outlined in Figure 3-1.

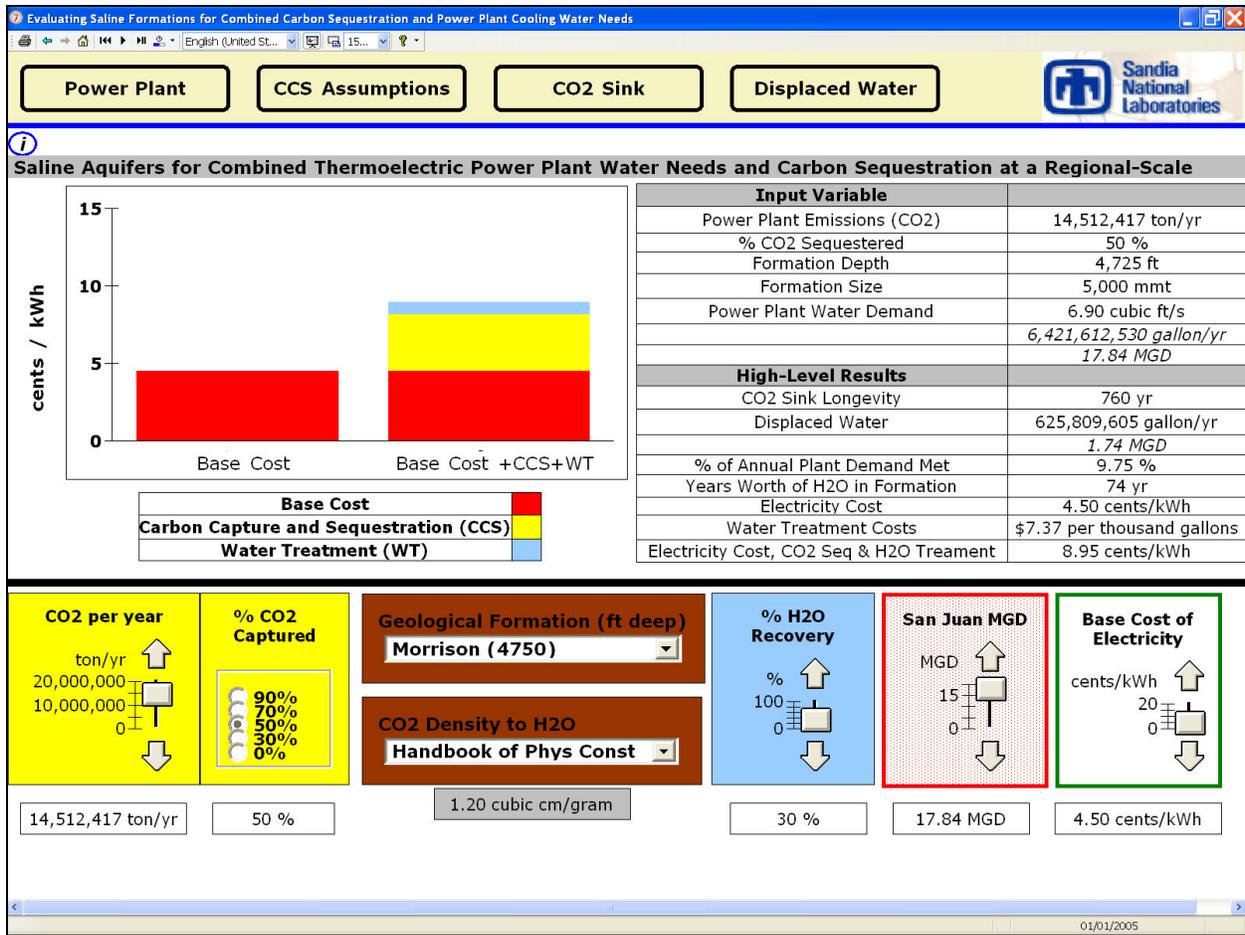


Figure 3-4: Prototype Front Screen of the Phase I Dynamic Simulation Model for the Water, Energy and Carbon Sequestration (WECS) Integrated Assessment Modeling.

### Sensitivity Analysis: Water Recovery Scenario Framework

Figure 3-4 illustrates a base case scenario analysis from which the model users can develop numerous sensitivity analyses. For example, the base case scenario assumes the power plant may capture 50% of the CO<sub>2</sub> it emits. Changing the level of CO<sub>2</sub> captured leads to changes in the lifetime of the geological formation to accept CO<sub>2</sub>, the number of years for which the extracted water may meet the power plant's demand, and the economics associated with the system as a whole. The sliders enable model users to change the volume of CO<sub>2</sub> captured per year, the geological formation under consideration, the density to displace water at depth, the percent of recoverable brackish water from the deep saline formation, the water demand by the cooling towers at the SJGS in million gallons per day (MGD), and the hypothetical cost of electricity used as the basis to calculate increases due to capturing and sequestering CO<sub>2</sub> and withdrawing and treating brackish water. Table 3-3 illustrates the variability in these scenarios across different percent levels of capturing CO<sub>2</sub> from the power plant.

**Table 3-3: Carbon Capture, Water Treatment and Electricity Cost Scenarios.**

<b>Percent of CO<sub>2</sub> Captured →</b>	<b>0</b>	<b>30</b>	<b>50</b>	<b>70</b>	<b>90</b>
CO <sub>2</sub> Sink Longevity (years)	n/a	1,266	760	543	422
Displaced Water (million gallons /year)	n/a	376	626	876	1,126
Annual Plant Cooling Towers' Demand Met (%)	n/a	5.85	9.75	13.64	17.54
Years Worth of H <sub>2</sub> O in Formation (years meeting all of the plant's needs)* [years meeting only 9.75% of the plant's 17.8 MGD water requirement]*	n/a	74 [760]	74 [760]	74 [760]	74 [760]
H <sub>2</sub> O displaced (Billion gallons) (Potential water volume assuming 30% recovery).	n/a	475	475	475	475
Water Treatment Costs (\$ per thousand gallons)	n/a	11.33	7.37	5.66	4.71
Electricity Cost, CO <sub>2</sub> Seq & H <sub>2</sub> O Treatment (cents/kWh)	n/a	8	9	10	12

n/a: not applicable; \*Assuming potential water volume recovery of 30%.

The high-level results given in Table 3-3 indicate that as the percent of CO<sub>2</sub> captured increases, the potential to displace brackish water also increases. Similarly, the percent of annual water demands of the power plant met by the formation water may also increase as the flow rates of sequestered CO<sub>2</sub> increase to displace the water. One of many key assumptions to further study and verify (or bound) are the actual displacement of water by the potential CO<sub>2</sub> plume. There may be a situation where in fact the communication between the CO<sub>2</sub> and the brackish water is such that water would not be displaced for many years. Therefore, we assume the brackish water is driven by pumping rather than any reliable CO<sub>2</sub> push. This would effectively make the full system two in one; a CO<sub>2</sub> sequestration system married with a brackish water extraction and treatment system that may not be connected within the formation for some time – if ever. Hence, the costs, flow rates and years worth of CO<sub>2</sub> storage resource and water supply could change drastically.

### ***Model Attributes to Develop Further in Phase II:***

The challenge with modeling the four separate systems (power plant, CO<sub>2</sub> capture, sequestration and water displacement in the geological formation, and water treatment) is the ability to capture sufficient detail to ‘tell the story’ of the system. Are the flow rates assumed by the CO<sub>2</sub> sequestration and water withdrawal and treatment sustainable for the number of years of interest to the power plant (e.g., decades to hundreds of years)? The following items list a few considerations the model may consider addressing in Phase II of the analysis.

#### Power Plant / CO<sub>2</sub> System:

- Will the cost to capture and sequester the CO<sub>2</sub> change over time? If so, what might that range be?
  - This will have implications for the lifetime of the plant, the formation, and the costs of the system.
- How long will the power plant last?
  - What are the costs for CO<sub>2</sub> capture retrofit versus a new power plant?
  - Will the geological CO<sub>2</sub> storage unit's lifetime (100s yrs) outlast the power plant's lifetime (10s years)?
  - Will the extracted water number of years (10s - <100) outlast the power plant's lifetime (10s)?

#### Geological System:

- What are the costs associated with CO<sub>2</sub> injection wells?
- Can the geological system (deep saline formation) absorb CO<sub>2</sub> at a rate commensurate with the desired injection rate?
  - If it cannot, how does this affect the lifetime of the formation to remain a CO<sub>2</sub> sink, a H<sub>2</sub>O source, and its effects on the cost of the system?
  - What types of measurement, monitoring and verification (MMV) technologies may the CO<sub>2</sub> system utilize?

#### Water Extraction & Treatment:

- Will the CO<sub>2</sub> displace the water at the rates we think it might?
  - What is the time scale involved?
- Is the absolute amount of water in the formation known?
- If the CO<sub>2</sub> displacing the H<sub>2</sub>O system does not perform as expected (e.g., 30% of the H<sub>2</sub>O expected to be recovered), could the power plant simply extract the water on its own through wells?
- Water Use limits to the Saline Formation Waters? Institutional Issues (Regulations).
  - Other unexpected items that could affect either the performance or economics of the system.

### ***Regional Assessment Model References:***

Clark, S.P., Jr., 1966, Handbook of Physical Constants, Geological Society of America Memoir 97, Published by the Society, GSA Publishers, NY, NY., 587 pp.

NatCarb, 2007, <http://www.natcarb.org/> and [http://drysdale.kgs.ku.edu/natcarb/eps/natcarb\\_alpha\\_content.cfm](http://drysdale.kgs.ku.edu/natcarb/eps/natcarb_alpha_content.cfm)) as of Spring 2008.

National Energy Technology Laboratory (NETL), 2007, Carbon Dioxide Capture from Existing Coal-Fired Power Plants. DOE/NETL-401-110907. (Final Report (Original Issue Date, December 2006)), Revision Date, November.

Environmental Protection Agency (EPA), 2006, eGRID2006 Version 2.1 Plant File (Year 2004 Data), As of March 3, 2008.

## **SUMMARY AND FOLLOW ON RECOMMENDATIONS:**

The Phase I work efforts identified a potentially suitable power plant, geological saline aquifer formation, and water treatment system to address the initial, high-level results of a combined CO<sub>2</sub> sequestration and brackish water treatment for cooling case study. Using the San Juan Power Plant, combined with the Morrison formation and finally employing a High Efficiency Reverse Osmosis system with a Brine Concentrator (HERO+BC) there may be several hundred years worth of CO<sub>2</sub> storage and unconventional water supply potential in the San Juan Basin. The central purpose of the analysis was to develop a working analytical framework to help describe the conceptual power to CO<sub>2</sub> sequestration to water treatment system that could potentially be applied to other regions of the country. Phase II of this project will further address several key scientific components of this conceptual system such as the potential injection rates of CO<sub>2</sub> into the Morrison (or analogous) formation, the potential rate of migration of the CO<sub>2</sub> within the formation, the time scales involved with each of the four key system's components (power plant, carbon capture, geological formation and water treatment), and finally the economics associated with a combined system of this type.

# APPENDIX 1. DETAILED DESALINATION COST ESTIMATE INFORMATION

Temp (°C)	$\rho$ (g/cm <sup>3</sup> )	$\rho$ (lb/ft <sup>3</sup> )	g/g <sub>c</sub> (lb <sub>f</sub> /lb <sub>m</sub> )
0	0.9998	62.39	1
20	0.9982	62.29	1
40	0.9922	61.91	1
50	0.9891	61.72	1
60	0.9832	61.35	1
80	0.9718	60.64	1
100	0.9584	59.80	1

$$hp_{theoretical} = \frac{Q \rho H}{550 \frac{ft \ lb_f}{hp}}$$

$$hp_{actual} = \frac{hp_{theoretical}}{h}$$

$$\rho = \frac{g}{g_c} r$$

$$H = TDH, ft = H_L + H_F + H_V$$

$$Q = flow, ft^3 / s$$

$$h = efficiency$$

Summary - Morrison GW Pumping Calculations (assumes 80 °C temp)					
Flow Rate (gpm)	Desalination Product Flow Rate (MGD)	Pipe D (in)	Avg Pump Energy Consumption (kwh/yr)	Energy cost (\$/kwh)	Annual Energy Cost
276	0.30	6	2,630,893	\$ 0.045	\$ 118,390
548	0.60	6	5,223,657	\$ 0.045	\$ 235,065
1,084	1.2	8	10,332,928	\$ 0.045	\$ 464,982
1,191	1.3	8	11,352,875	\$ 0.045	\$ 510,879
1,807	2	10	17,224,724	\$ 0.045	\$ 775,113
5,446	6	14	51,912,477	\$ 0.045	\$ 2,336,061
10,892	12	20	103,824,954	\$ 0.045	\$ 4,672,123
16,338	18	24	155,737,430	\$ 0.045	\$ 7,008,184

**Figure A-1: Formation Water Pumping Electrical Cost Estimation.**  
 Equations from Water Supply & Control (1998)  
 $\rho$  from Perry's Chemical Engineers' Handbook, 7th ed (1997)

Feed Water TDS	Energy Consumption (kwh/1000 gal perm)		
	LE RO	Std RO	EDR
1000	2.27	3.03	1.89
2000	2.80	3.60	2.76
<i>2500</i>	<i>3.10</i>	<i>3.91</i>	
3000	3.31	4.24	3.79
4000	3.97	4.73	4.92
<i>4500</i>	<i>4.30</i>	<i>5.11</i>	
5000	4.54	5.30	6.62
<b>6000</b>	<b>5.30</b>	<b>5.87</b>	
7000	<i>5.80</i>	6.43	
8000	<i>6.40</i>	7.10	
9000	<i>7.00</i>	7.76	
10000	<i>7.60</i>	8.33	
11000	<i>8.20</i>	<i>9.01</i>	
12000	<i>8.80</i>	<i>9.61</i>	
13000	<i>9.40</i>	<i>10.21</i>	
14000	<i>10.00</i>	<i>10.81</i>	
15000	<i>10.60</i>	<i>11.41</i>	
35000	<i>22.60</i>	<i>23.41</i>	

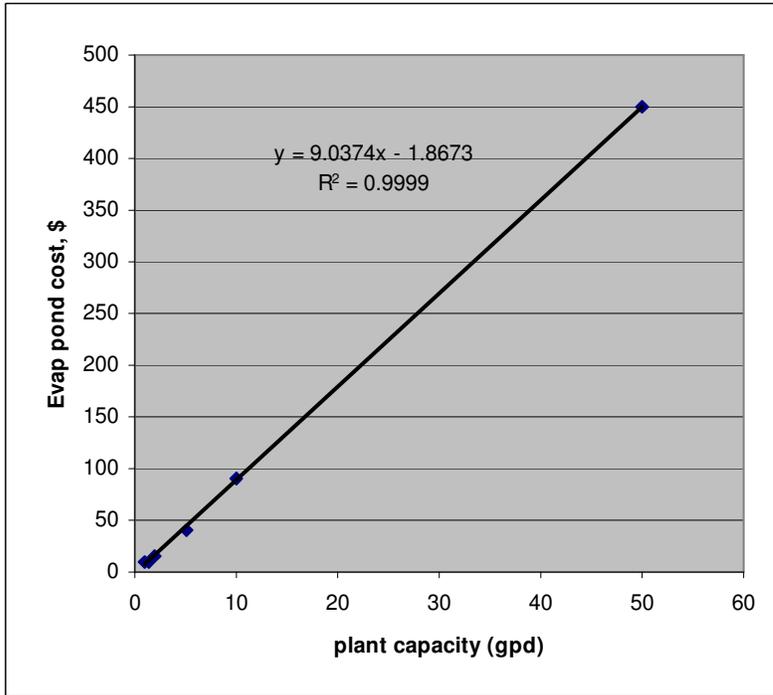
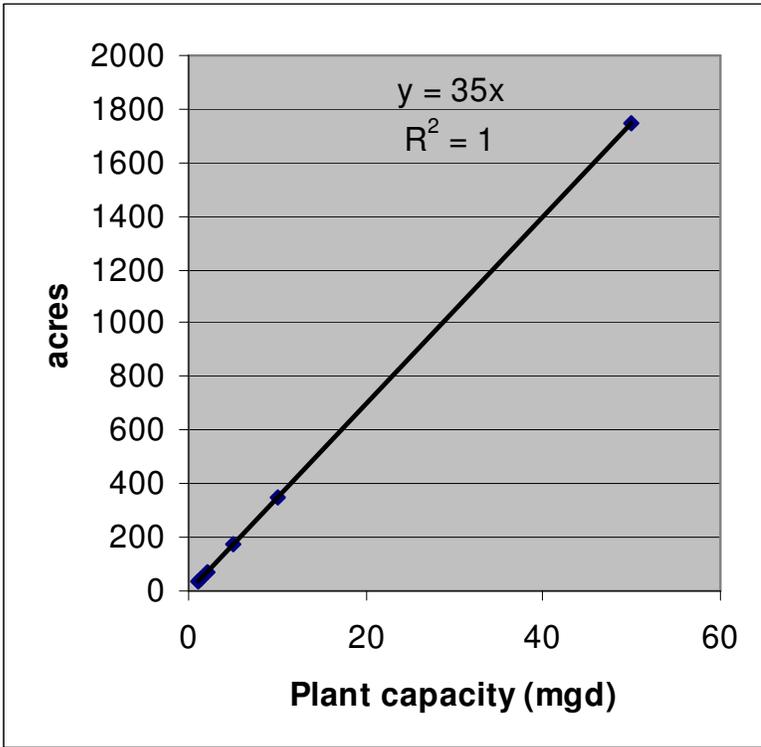
**Figure A-2: Desalination Power Estimation.**

Assumptions:

RO recovery = 75%

EDR recovery = 75%

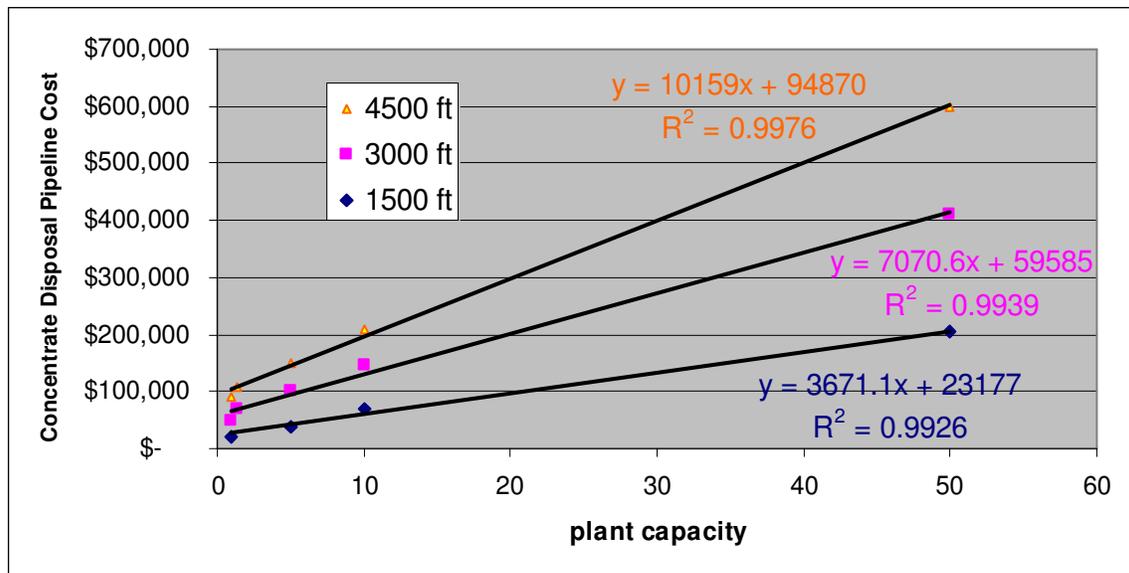
*(italics)* = estimated via regression analysis



**Figure A-3: USBR-based Calculations**  
 (all based on Desalting Handbook, 3<sup>rd</sup> edition).  
 (Evaporation Ponds (USBR Figure 9-12))

BWRO Concentrate disposal pipeline - use for concentrate disposal & brackish pipeline estimate  
(USBR Fig 9-11)

pipeline L(ft)	capacity	cost	Cost/mile
1500	1	\$ 20,000	\$ 70,400
1500	5	\$ 40,000	\$ 140,800
1500	10	\$ 70,000	\$ 246,400
1500	50	\$ 205,000	\$ 721,600
3000	1	\$ 50,000	\$ 88,000
3000	2	\$ 73,726	\$ 129,758
3000	5	\$ 100,000	\$ 176,000
3000	10	\$ 145,000	\$ 255,200
3000	50	\$ 410,000	\$ 721,600
4500	1	\$ 90,000	\$ 105,600
4500	2	\$ 115,188	\$ 135,154
4500	5	\$ 150,000	\$ 176,000
4500	10	\$ 210,000	\$ 246,400
4500	50	\$ 600,000	\$ 704,000



**Figure A-3: USBR-based Calculations (continued)**

(all based on Desalting Handbook, 3<sup>rd</sup> edition).

Plant Capacity (MGD)	Cost
1	\$ 2,000,000
2	\$ 2,389,786
5	\$ 3,500,000
10	\$ 4,800,000
50	\$ 12,000,000

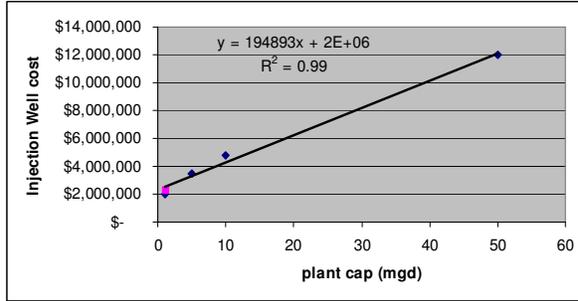


Figure A-4: Injection Well for Concentrate Disposal.

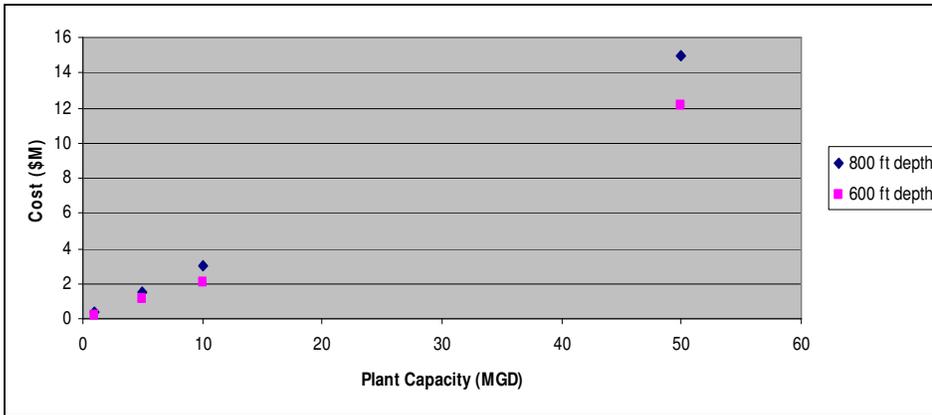


Figure A-5: Injection Well for Concentrate Disposal.  
(Used \$2,000/ft to allow for deeper well)

plant size (mgd)	Annual \$
1	170000
2	201775
5	250000
10	300000
50	420000

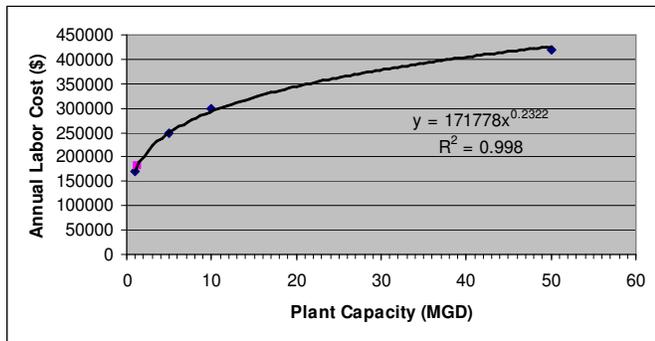


Figure A-6: Annual cost – labor.

plant size (mgd)	Annual \$
1	\$ 61,000
2	\$ 130,209
5	\$ 310,000
10	\$ 620,000
50	\$ 3,000,000

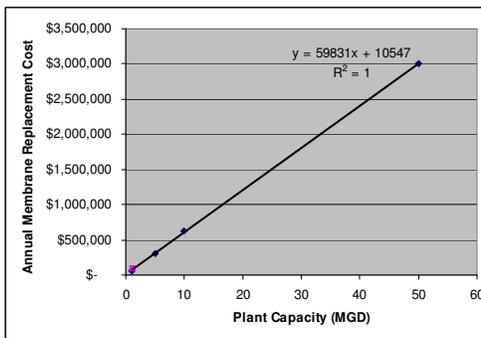


Figure A-7: Annual cost - chemicals for membranes (surface water).

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