Storing Carbon Dioxide in Saline Formations: Analyzing Extracted Water Treatment and Use for Power Plant Cooling

Peter H. Kobos, Sandia National Laboratories, (505) 845-7086, phkobos@sandia.gov
Jesse D. Roach, Sandia National Laboratories
Geoffrey T. Klise, Sandia National Laboratories
Jim L. Krumhansl, Sandia National Laboratories
Thomas A. Dewers, Sandia National Laboratories
Jason E. Heath, Sandia National Laboratories
Brian Dwyer, Sandia National Laboratories
David J. Borns, Sandia National Laboratories
Andrea McNemar, National Energy Technology Laboratory

Abstract

In an effort to address the potential to scale up of carbon dioxide (CO_2) capture and sequestration in the United States' saline formations, an assessment model is being developed using a national database and modeling tool. This tool builds upon the existing NatCarb database as well as supplemental geological information to address scale up potential for carbon dioxide storage within these formations. The focus of the assessment model is to specifically address the question, "Where are opportunities to couple CO_2 storage and extracted water use for existing and expanding power plants, and what are the economic impacts of these systems relative to traditional power systems?" Initial findings indicate that approximately less than 20% of all the existing complete saline formation well data points meet the working criteria for combined CO_2 storage and extracted water treatment systems.

1. Introduction

The Water Energy and Carbon Sequestration (WECS) model was developed to integrate the full data set of U.S. power plants, geological saline formations, carbon capture and sequestration scenarios, and saline formation water extraction and treatment technologies. The model, developed in Powersim Studio, also included a statistical binning of the saline formations based on their geochemical, depth, salinity and other important parameter profiles. These efforts build from several years' worth of research in an ongoing project in its first three phases. Phase I of the project developed a framework and model to assess a specific source of CO_2 (San Juan generating station in northwest New Mexico) to a specific sink for the CO_2 (the Morrison formation also in northwest New Mexico). In Phase II, the project expanded to include other regions of the U.S. For example, there is substantial variability associated with different saline formations, power plant configurations, and regional constraints such as the level of existing infrastructure that will affect the overall systems' costs.

In the beginning stages of Phase III presented here, a large down-selecting set of criteria, methodology and data assessment was developed. A well selector tool allows the analysis to assess saline formations according to criteria for storing specific volumes of CO_2. The national-level WECS model, (WECS II) currently evaluates implications of carbon capture and compression at any coal or natural gas-based power plant in the U.S. (sources of CO_2) and sequestration of that CO_2 in any of 325 deep saline formations in the U.S (sinks for CO_2). The estimated parameters include the distance from source to sink, costs associated with carbon capture, compression, transportation, and sequestration, the length of time the formation may last for a given CO_2 sequestration rate, how much water may be extracted to make room for the CO_2, and what the high-level costs of water treatment may be to reuse the extracted water to offset additional water demands at the power plant associated with carbon capture and compression. With this full analysis, multiple scenarios can be developed with custom site and sink combinations. In the coming years, the model will be used to evaluate carbon capture and sequestration with extracted water treatment at all currently operational coal and natural gas fired power plants in the U.S. Additionally, other sources of CO_2 can be included as desired based on custom options (e.g., hypothetical power plants using new technologies). This paper describes the current state of the WECS model's development for this multi-year effort.

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2. Model Architecture and Scope

The model's development has been based on a bottom-up approach both from the traditional definition of energy-economic-engineering modeling, the 'integrated assessment' model methodology, and from a pragmatic approach (e.g., begin with a single test case) then refining the analysis framework and extending it to multiple power generating stations and potential CO_2 sink locations.[i] The initial stages of the model's development analyzed a single power plant relative to a single saline formation (CO_2 sink). The current model (WECS II) is able to compare any combination of a single power plant (amongst the U.S. coal and natural gas power plants) with any single saline formation in the U.S. Future work may address the capability to simultaneously compare all CO_2 sources to all saline formation CO_2 sinks through time under hypothetical carbon emission abatement scenarios.

The WECS II model is divided into 5 interrelated modules: (1) a power plant module, (2) a carbon (CO_2) capture module, (3) a carbon (CO_2) sequestration (geologic formations) module, (4) a water extraction module, and (5) an integrating power cost module. The relationships between the modules, and the key information passed between them is shown in Figure 1.

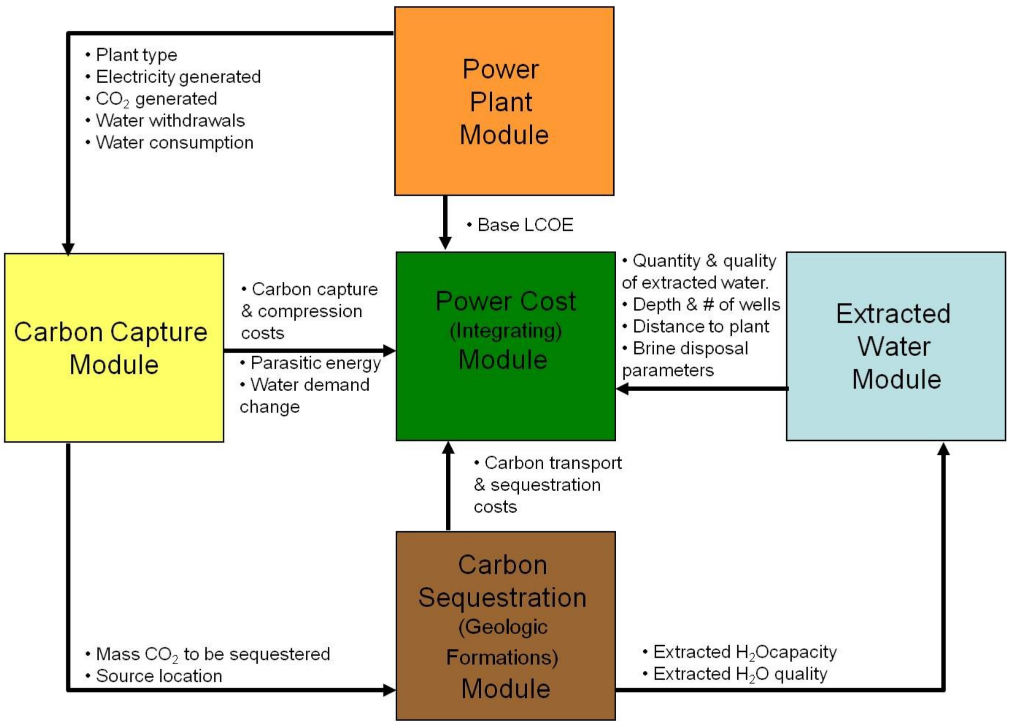


Figure 1. Modular structure of the WECS II model.

2.1. Power Plant Module Inputs

The power plant module allows users to select a specific (or generic) power plant from the existing U.S. fleet. These types of power plants represent either subcritical or supercritical pulverized coal (PC), integrated gasification combined cycle (IGCC), natural gas combined cycle (NGCC), or a natural gas turbine system (Figure 2). The plant's location, overall generating capacity and capacity factors can be changed to address custom options at a specific location. In WECS II, the overall plant lifetime has an impact on the financial calculations in terms of how quickly any investment in carbon capture and sequestration infrastructure must be recovered. In future potential iterations of the model, the plant lifetime will become important for time based simulations of carbon capture and sequestration by multiple plants to multiple sinks.

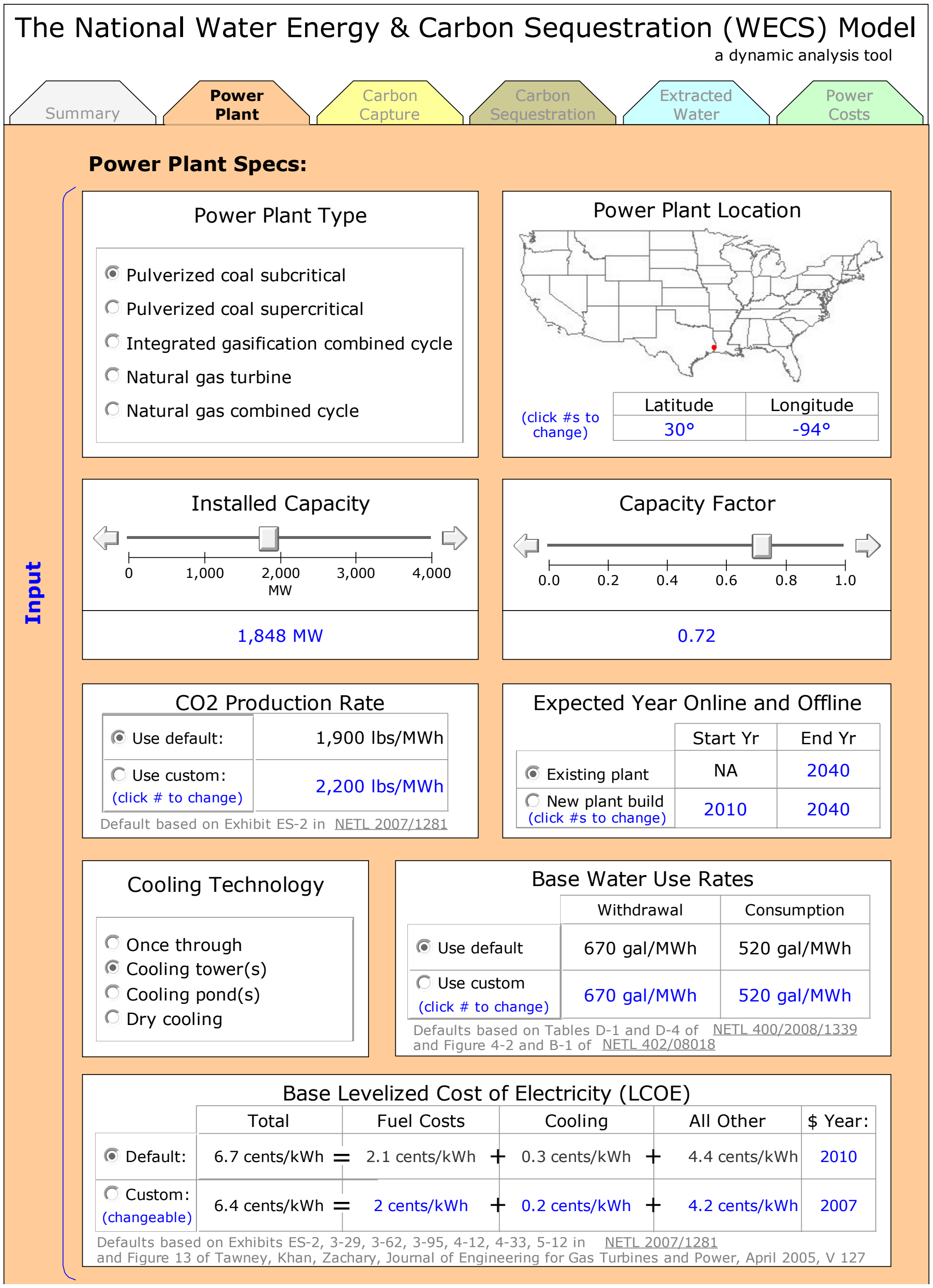


Figure 2. User interface inputs to WECS II power plant module.
Values in blue and radio buttons or slider bars can be changed by the user.

The selected cooling technology and power plant type determine a default water withdrawal and consumption rate as seen in Figure 2. Additionally, the analysis allows users to build from the base case levelized costs of electricity (LCOE) for the plant broken down into fuel costs, cooling, and other costs. This also includes specifying the reference year to display the default costs (and all other costs in the model) in as well as the reference year associated with the custom cost input values.[ii]

The defaults for the power plant module are based on analysis of data contained in several NETL (2007a, 2008, 2009) and Tawney et al. (2005) reports characterizing aspects of power plant operations and can be changed to custom values to allow for site-specific scenario analysis.

The default CO_2 production rates for each technology type of power plant used by the model are shown in Table 1.

Power Plant Type	Default CO_2 Production Rate (lb/MWh)
Pulverized Coal: Subcritical	1900
Pulverized Coal: Supercritical	1800
Integrated Gas Combined Cycle (IGCC)	1700
Natural Gas Turbine	1000
Natural Gas Combined Cycle	800

Table 1. Default CO_2 production rates utilized by the WECS II power plant module.[iii]

Cooling Technology

The cooling technology is also specified in the power plant module with a default use of cooling towers and the option to choose once through, cooling ponds, or dry cooling instead. For each of these configurations, baseline water withdrawal and consumption rates and LCOE are needed. As with CO_2 production rate, the model is set up so that the defaults can be overridden by the user if they have specific information or want to evaluate the impact of different values. Table 2 illustrates the base case values used in the model.

Model Default Base Plant Water Use					
Withdrawal		Base H_2O withdrawal [gal/MWh]			
	Plant Type	Once Through	Tower	Cooling Pond	Dry
	PC Sub	27113	531	17927	76
	PC Super	22611	669	15057	67
	IGCC	11002	226	7284	57
	NGCC	9010	150	5950	4
Consumption		Base H_2O consumption [gal/MWh]			
	Plant Type	Once Through	Tower	Cooling Pond	Dry
	PC Sub	138	462	804	68
	PC Super	124	518	64	59
	IGCC	32	173	220	53
	NGCC	20	130	240	4
Data	Dry cooling values for PC and IGCC taken from non cooling term in Figures 4-2 and B-1 of NETL 402/080108 (2009). IGCC once-through and cooling pond values (in blue) are interpolated based on surrounding values. All other values are from Tables D-1 and D-4 in NETL-400/2008/1339 (2008).				

Table 2. Model default water withdrawal and consumption rates for different power plant and cooling technologies.[iv]

To estimate default water withdrawal and consumption rates for each of the other potential plant configurations, information was adapted from the NETL (2008) report. The assumptions within NETL (2009) were used to estimate dry cooling requirements for PC and IGCC plant types by taking the water requirements for processes besides cooling. The dry-fed IGCC plant types were assumed for the IGCC plants. Water usage by an IGCC plant with once through or cooling pond systems was not available in either report, and were estimated by interpolation between the PC supercritical and NGCC values for once through and cooling pond cooling as compared to the relationship of all three technologies for tower cooling. The relatively small sample size (five data points) that were used to initially derive it (NETL, 2008) suggest it may not be widely representative. Therefore, it is recommended that where more specific information is available, it should be incorporated by using the custom input capability of the WECS II model.

Levelized Cost of Energy

The levelized cost of electricity (LCOE) estimates for new PC, IGCC, and NGCC plants with tower cooling are adapted from Exhibit ES-2 of NETL (2007a). The IGCC value is an average of three IGCC systems considered in the NETL (2007a) report.[v] Additional costs associated with the cooling system were estimated by assuming 10% of fixed costs (labor) and 100% of water costs (variable operating cost) are associated with the cooling system. Finally, the total capital, fixed, and variable costs associated with the cooling system were levelized into the portion of LCOE attributable to the cooling system. The percent of LCOE estimated to be a result of the cooling system is shown in Column B of Table 3.

Column ID	(A)	(B)	(C)	(D)	(E)	(F)
Method	NETL (2007a)		A*B	C*0.64	C*2.7	A-C
Plant Type	LCOE (¢/kWh)	Plant Cost From Cooling System (%)	Cost of tower cooling (¢/kWh)	Cost of once-through cooling (¢/kWh)	Cost of dry cooling (¢/kWh)	Cost w/o cooling (¢/kWh)
PC Sub-Cooling Tower	6.4	3.7	0.24	0.15	0.64	6.16
PC Super-Cooling Tower	6.3	3.7	0.23	0.15	0.62	6.07
IGCC-Cooling Tower	7.8	2.8	0.22	0.14	0.59	7.58
NGCC-Cooling Tower	6.8	1.5	0.10	0.06	0.27	6.70

Table 3. Cost of Power Plant Cooling Default Values used in the WECS Model. Columns A and B are based on data in NETL (2007a) report 2007/1281 Exhibits ES-2, 3-29, 3-62, 3-95, 4-12, 4-33, and 5-12. Factors 0.64 and 2.7 represent relative costs of once-through and dry cooling systems respectively compared to tower cooling as reported in Tawney et al. (2005). The calculations in columns C-F use the Tawney et al. (2005) relative cooling cost factors. [vi]

Finally, the LCOE exclusive of cooling costs is estimated by subtracting the estimated cost of tower cooling in Column C of Table 3 from the total LCOE in Column A of Table 3. Results are shown in Column F of Table 3.

Gas turbine systems are assumed to have a LCOE of 10 cents per kilowatt-hour (c/kWh) and no cooling system. These assumptions, along with the information in Table 3 were sufficient to estimate a default LCOE for each plant configuration considered by the model as summarized in Table 4.

LCOE (cents/kWh)				
Plant Type	**One Through**	**Tower**	**Cooling Pond**	**Dry**
Pulverized Coal, Subcritical	6.3	6.4	6.3	6.8
Pulverized Coal, Supercritical	6.2	6.3	6.2	6.7
Integrated Gasification Combined Cycle (IGCC)	7.7	7.8	7.7	8.2
Gas Turbine	10	10	10	10
Natural Gas Combined Cycle (NGCC)	6.8	6.8	6.8	7.0

Table 4. Default Levelized Cost of Electricity (LCOE) values used by the model (2007 $US).

The default water use and LCOE values described here are intended to represent initial starting values that can be changed by the model user. The model employs these assumptions and user inputs to calculate the total annual electricity generation, CO_2 production, water withdrawal demand, and water consumption, and energy production costs at the plant level as seen in Figure 3. Additionally, the user interface to the model allows one to compare the electricity generation, capacity, capacity factor, and emission rates to all other power plants using coal or gas in operation in the U.S. in 2005 as reported in eGRID2007 (2007).

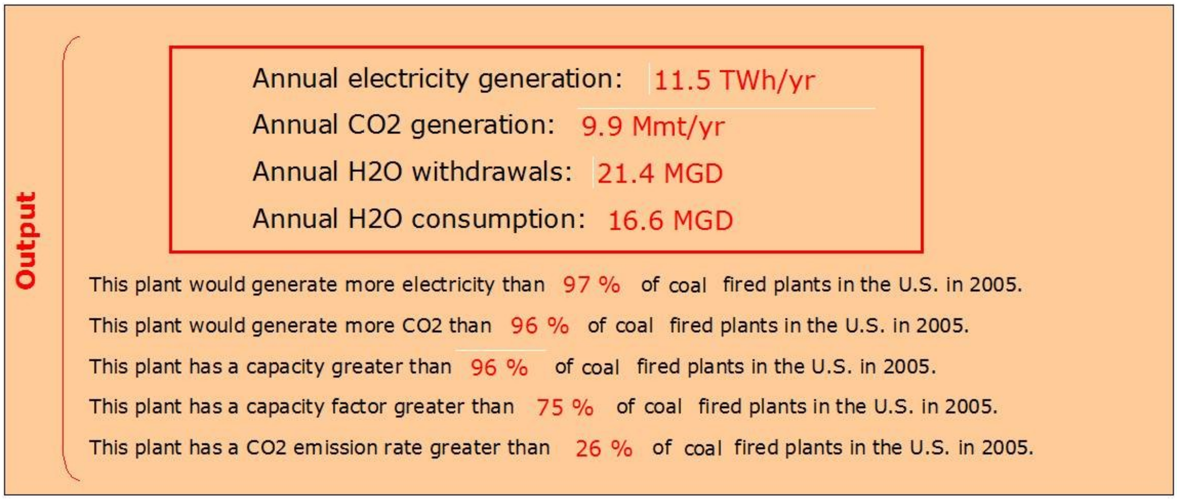


Figure 3. User interface outputs from WECS II power plant module including electricity generation in Terawatt hours per year (TWh/yr), CO_2 generation in millions of metric tonnes per year (Mmt/yr), and water withdrawals and consumption in millions of gallons per day (MGD), and how plant properties compare to the suite of power plants operating in 2005.

2.2. Carbon Capture Module

Figure 4 shows the user interface for changes in inputs to the carbon capture module of the WECS II model. Once the percentage of CO_2 to be captured has been chosen, the model selects an associated parasitic energy requirement from a set of curves relating % CO_2 capture to parasitic energy requirements by power plant type as seen in Figure 4. A default relationship is specified by the dashed line in the graph, with the default passing through the red crosses for pulverized coal plants, and of the same relative shape but passing through the purple or orange cross for NGCC and IGCC plants respectively (Figure 4 and Table 5). The blue solid line can be adjusted by clicking on it once to see the points that describe it corresponding to 0%, 30%, 50%, 70%, 90% and 100% CO_2 capture. These points can then be moved up and down until the desired relationship is shown. With these inputs, the model has the custom parasitic energy requirements selected for carbon capture and compression as a percentage of the energy production for the power plant specified.

The WECS II model requires that make-up power be produced to offset parasitic losses associated with carbon capture and compression at the original power plant. The make-up power is assumed to come from a new power plant (with customizable options) located close to the original power plant. It should be noted that for new power plants, the notion of makeup power is not applicable. In these cases the cost, CO_2 generation rates, and water requirements of the make-up power plant can be set to zero and all power plant characteristics for the new power plant with sequestration capabilities would be defined in the power plant module.

In addition to water demand associated with makeup power, CO_2 capture and compression also results in additional water demand at the original power plant. This 'process' water is largely a result of additional cooling demands due to compression of the captured CO_2, and is specified in Table 6.

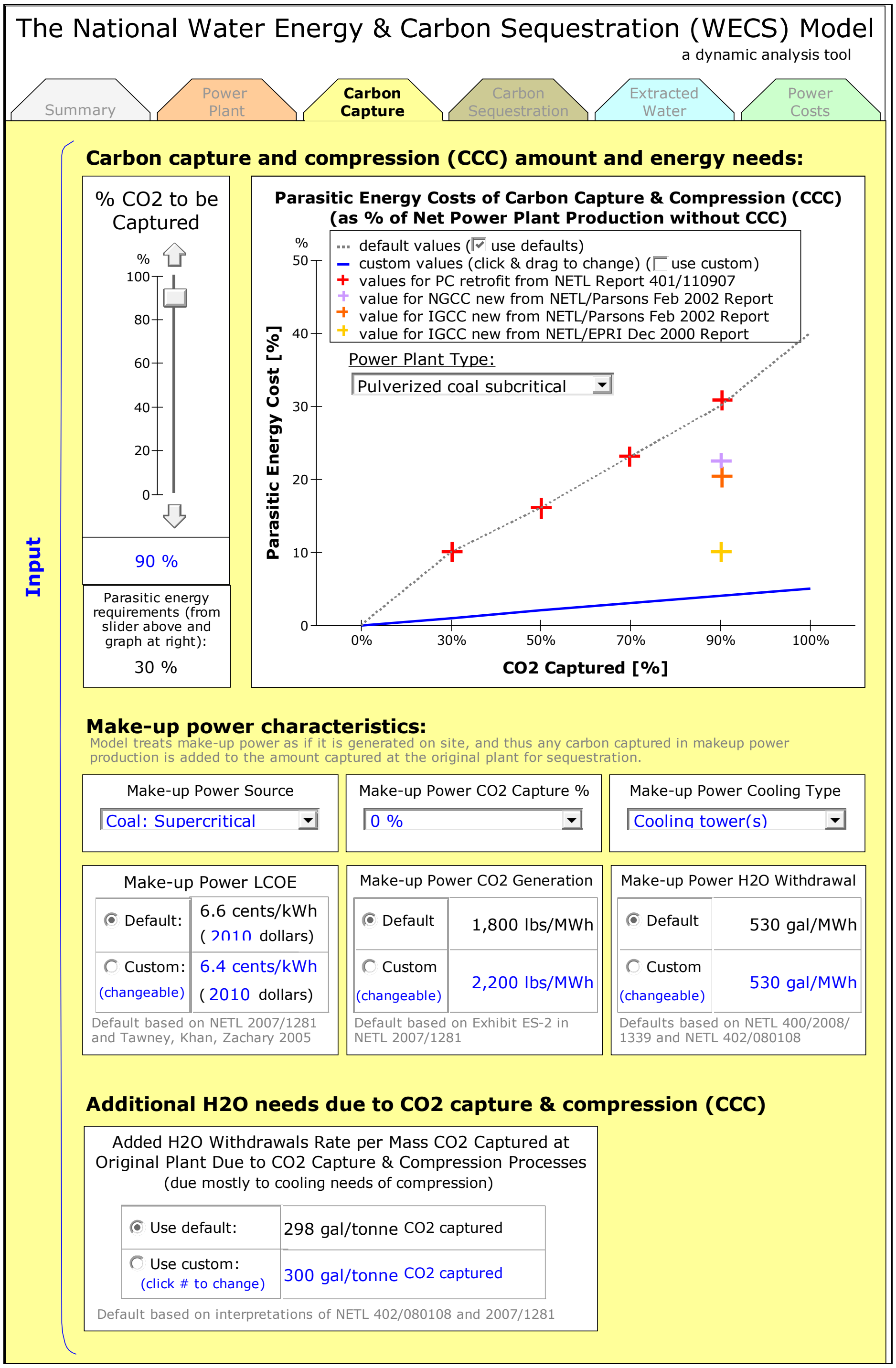


Figure 4. User interface inputs to WECS II carbon capture module. Values in blue and radio buttons or slider bars can be changed by the user.

	% Carbon Captured and Compressed				
Plant Type	**30%**	**50%**	**70%**	**90%**	**100%**
PC Sub	10%	16%	23%	30%	40%
PC Super	10%	16%	23%	30%	40%
IGCC	6%	11%	15%	20%	27%
Gas Turbine	8%	14%	19%	25%	34%
NGCC	7%	12%	17%	22%	29%

Table 5. Default parasitic energy penalties associated with percentage of CO_2 capture as a function of power plant type. NETL (2007b) and NETL/CTC (2002).

The power required for carbon capture and compressions systems at power plants also requires additional water at the original power plant due mostly to cooling requirements associated with compression of the CO_2 to a supercritical state. This marginal water demand per mass CO_2 captured was calculated based on carbon emissions and water use for carbon capture values reported by NETL (2007a) and Appendix B in NETL (2009), respectively. These calculations and the resulting default values for marginal water use at the original power plant due to CO_2 capture and compression are shown in Table 6. The indicated values assume the use of cooling towers. Scenarios utilizing other cooling technologies require custom input from the model user.

	Column ID	A	B	C
	Column Name	CO_2 Emissions	Marginal H_2O withdrawal for 90% CO_2 capture	Marginal H_2O withdrawal per tonne CO_2 captured
	Unit	[lb CO_2/MMBTU]	[gal/MMBTU]	[gal/tonne CO_2]
	Method	NETL (2007a) 2007/1281	NETL (2009) report 402/080108	2204.6*B/(0.9A)
Plant Type	PC Sub	**203**	**24.7**	298
	PC Super	**203**	**24.4**	294
	IGCC	**200**	**9.55**	117
	Gas Turbine	140	22.1	387
	NGCC	**119**	**22.1**	455

Table 6. Default marginal water withdrawal values per mass of CO_2 captured by power plant type.

Once all user inputs have been selected, the carbon capture module calculates the marginal water demand, and the total amount of CO_2 captured and compressed at the original and makeup power plants. Figure 5 illustrates the salient output from a subcritical pulverized coal power plant.

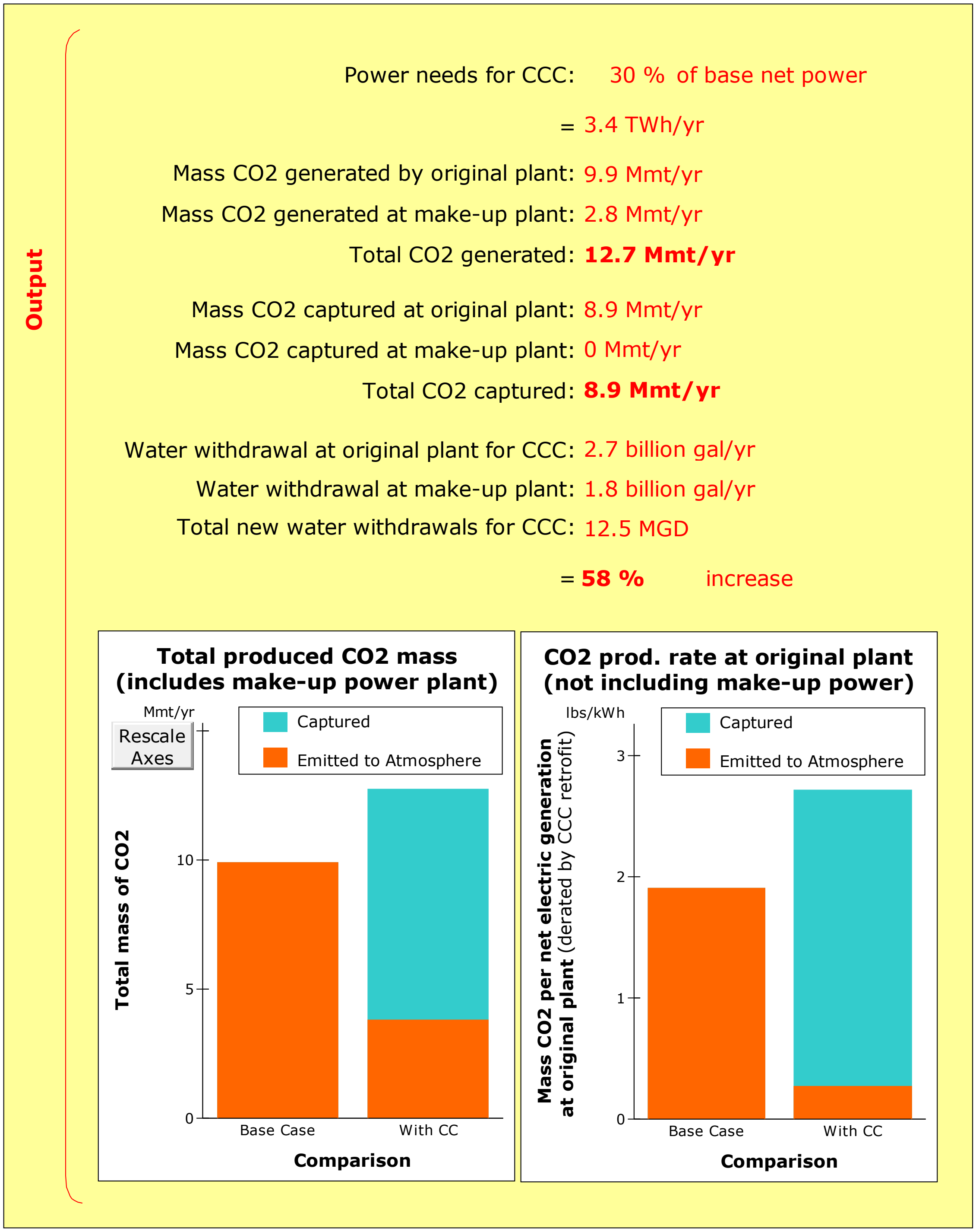


Figure 5. User interface outputs from WECS II carbon capture module include parasitic energy requirements, CO_2 generation and water use values associated with both the original subcritical pulverized coal plant (approximately 1800 MW) and makeup power plants. The bar chart on the left shows that the total amount of CO_2 generation increases with CO_2 capture, but the amount released to the atmosphere decreases. The bar chart on the right shows that the amount of CO_2 generated per net energy produced at the source plant increases due to the decrease in net energy production resulting from the parasitic energy requirements of carbon capture. Note: Carbon Capture and Compression (CCC).

2.3. Carbon Sequestration Module

The carbon sequestration module utilizes geologic information to calculate sequestration costs from the selected power plant to any of 325 geologic formations listed in the NatCarb database (NatCarb, 2008).[vii] The carbon sequestration module estimates the cost of piping and injecting CO_2 from the specified source into a given formation. The module calculates the costs associated with transportation and sequestration of the CO_2 specified by the carbon capture module from the source specified by the power plant module, to any given formation considered for sequestration. When a user selects a specific formation the default values will be specified based on the chosen formation. The partnership, basin, and formation name for each of the 325 formations are from the National Carbon Atlas (NatCarb 2008) database. Figure 6 illustrates the down selection process used to identify wells that meet the saline formation CO_2 storage and water extraction criteria (e.g., 2,500 feet below the surface, TDS between 10,000 and 30,000 mg/l, etc.).

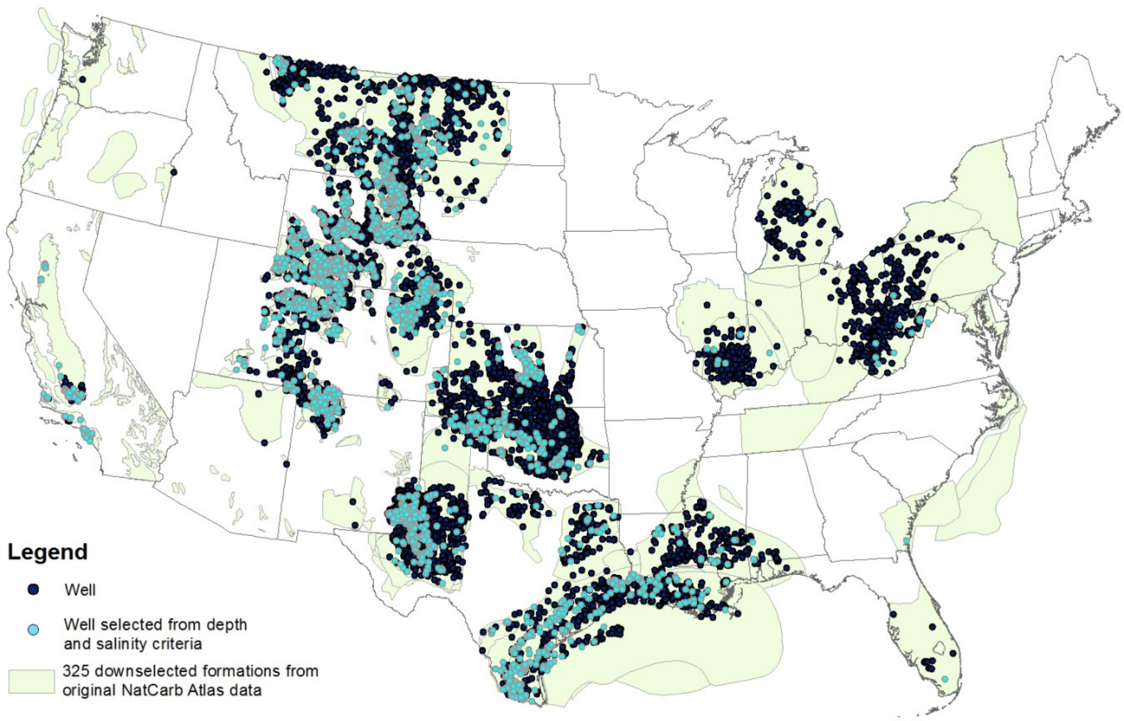


Figure 6. Selected wells from the NatCarb database that meet specific selection criteria.

Using this information, the carbon sequestration module provides a cost estimate for CO_2 sequestration to all of the formations considered. It begins by calculating the distance from the power plant selected to each of the potential formations based on a centriod location of the target formation. The spatial area of the formation is estimated such that a CO_2 pipeline would only need to extend to the edge of the formation, and not to the actual formation centroid. Although the carbon sequestration module calculates expected sequestration costs for all formations, only formations within the distance specified in Figure 7 will be considered as the model chosen default formation.

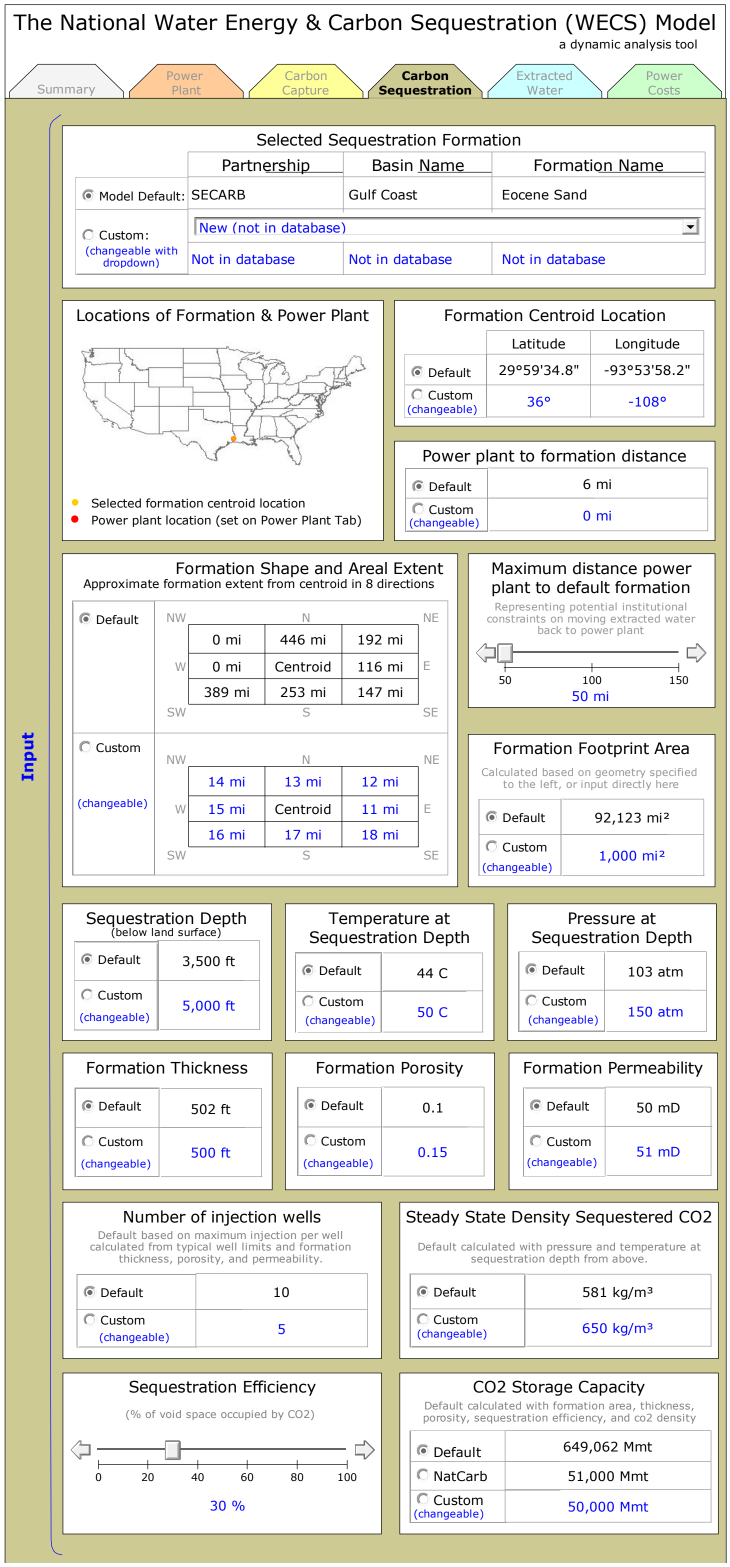


Figure 7. User interface inputs to WECS II carbon sequestration module. Values in blue and radio buttons or slider bars can be changed by the user.

Once the depth of sequestration is determined, default values for temperature and pressure are calculated based on geothermal gradient estimates, and an assumed hydrostatic pressure gradient starting at the surface. The model uses this information to calculate volumes of CO_2 managed at depth.

Default values for formation CO_2 storage capacity, thickness, porosity, temperature and pressure are based on published data in the National Carbon Sequestration Atlas (NatCarb, 2008) where available. Where data are not found in the present NatCarb database, general estimates are based on relationships between formation geology, depth, and porosity/permeability where available (these continue to be refined or included). Figure 7 also specifies the sequestration efficiency or "sweep efficiency" (meaning the percent of void space that would actually be occupied by supercritical CO_2) built from a base case value of 30%. Sequestration efficiency is used along with the formation area, thickness, porosity, and CO_2 density to calculate the mass storage capacity of the formation. Using these results, the model user can choose between the calculated default storage capacity, the NatCarb reported capacity, or a custom value to begin to address the often relatively large range of calculated volumes reported for saline formations to store CO_2.[viii]

For all 325 potential formations in NatCarb, the distance between source and sink, the depth of sequestration, the number of injection wells needed, and the capacity of the formation is passed to the power costs module for use in calculation of costs from which the default formation is selected. Additionally, important variables are displayed in the output section of the carbon sequestration module user interface shown in Figure 8.

Output	Distance from source to sink (linear distance):	6.2 mi
	Sequestration depth:	5,000 ft
	Steady state temperature at sequestration depth:	55.1 C
	Steady state pressure at sequestration depth:	147.5 atm
	Steady state density of CO2 in sequestration formation:	653 kg/m³
	Expected life of sequestration formation for selected source:	82,000 yr
	Number of sequestration (injection) wells needed:	10
	Total rate of sequestration:	8.92 Mmt/yr
	Levelized cost of CO2 transport and sequestration:	0.05 cents/kWh

Figure 8. User interface outputs from WECS II carbon sequestration module that include distance between power plant and sink, depth and rate of sequestration, steady state temperature, pressure, and resulting CO_2 density at the sequestration depth, expected life of the formation, required number of injection wells, and the levelized cost of the CO_2 transport and sequestration per unit of energy generated.

Addressing Uncertainty in the Geological Data

To address the impact of uncertainty (or availability) of data, such as porosity and permeability, on important performance criteria such as 'sweep efficiency' and similar parameters, the project will look to develop probabilistic distribution functions (PDF) for select parameters. Important parameters such as permeability can vary many orders of magnitude within common reservoir rocks (e.g., sandstones, limestones), and the parameters can also vary with the scale of measurement (e.g., measurements made on core or via pump tests).

Geostatistical methods provide techniques to deterministically or stochastically estimate the spatial distribution of subsurface parameters at unsampled locations. They also offer methods for quantitatively describing spatial relationships of parameters. Especially important is the ability to provide estimates of uncertainty associated with the interpolated and extrapolated parameter values (Kelkar and Perez, 2002). To include uncertainty in reservoir and caprock properties in the WECS model, the team is running multiple 3D realizations of injection and fluid extraction in the Mount Simon Formation, from which the analysis is constructing probability distribution functions in plume extent, injectivity and plume sweep efficiency. These can be used within the WECS structure to assess the relative importance of uncertainty in reservoir parameters in assessing the overall economics of the coupled use model. The Mount Simon Formation is an important storage target in the Illinois Basin in the U.S. (Finley, 2005).

This involves running multiple realizations of injection in a reservoir model (TOUGH2; Pruess et al., 1999) with spatially correlated porosity, permeability, and capillary pressure functions, and examining the resulting variation in plume migration, injectivity, and sweep efficiency. To allow for heterogeneity in single and multiphase transport properties in TOUGH2, distributions of porosity and permeability for the Mount Simon Formation sandstone were taken from core and wireline logs from previous studies in the Illinois Basin by the Midwest Geological Sequestration Consortium (Finley, 2005). Spatial correlations in porosity are quantifiable via correlation functions or graphically in variograms (for the Mount Simon, see Finley, 2005). The analysis is generating multiple realizations of porosity distributions mapped onto a TOUGH2 grid using this variogram information and the geostatistical Sequential Gaussian algorithm via the computer program "SGSIM" of the GSLIB family of programs (Deutsch and Journel, 1998). Correlated permeability distributions were obtained using the coregionalization method, which uses a relationship between core and wireline log porosity values and permeability measurements made on core, while still producing spatially correlated permeability values (Rautman and McKenna, 1997). One such realization is shown below in Figure 9(A), with grid block size of 10 m, 10 m, and 1 m in the x, y, and z directions, respectively for a 500mx500mx35m domain.

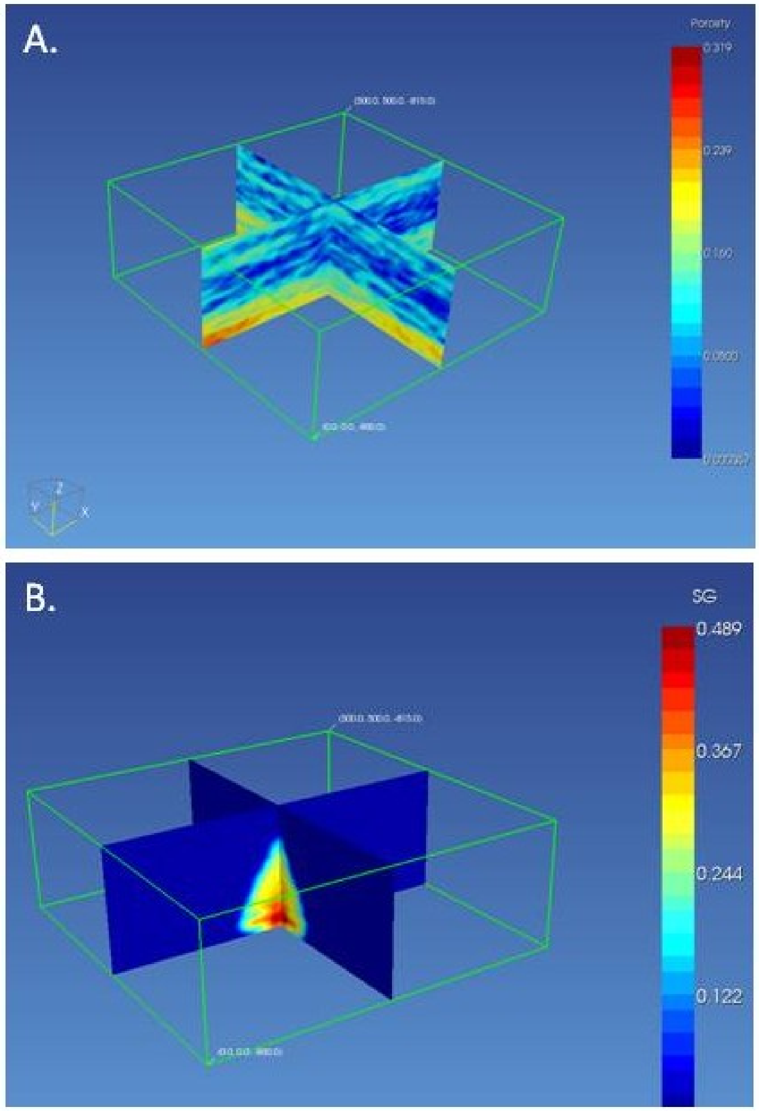


Figure 9. (A). Example of porosity realization of the Mount Simon Formation upper sandstone facies. In this realization there is a lower, more porous zone. (B). After three years of injection, supercritical CO_2 has produced an inverted profile due to the heterogeneity, in particular advancing further along the bottom of the domain. This plume shape is counter to that observed for injection into a homogeneous body (i.e., due to gravity override). 5x vertical exaggeration in the vertical direction.

Multiphase fluid flow modeling is being performed using these spatially correlated realizations in porosity, permeability, and capillary pressure using TOUGH2 (Pruess et al., 1999) and the ECO2N equation of state module (Pruess, 2005). An example after 3 years of injection at a rate of 0.15 kg/s (~5x10^{-3} Mtonne/yr) is shown in Figure 9(B). Inclusion of heterogeneity in this case has produced a plume shape that is inverted from the usual 'gravity override' plume shape, a plume migration that is about twice that than a homogeneous case (due to fast paths), an injectivity that is about an order of magnitude less, and a sweep efficiency that is at least an order of magnitude less than the homogeneous case. The team is running multiple realizations of CO_2 injection in this manner, from which it can extract probability distribution functions of these parameters. With this type of information, the overarching system's flow dynamics can be better categorized, and the resulting costs (ultimately levelized cost of electricity) will reflect the uncertainties present throughout the physical CO_2 sequestration and water extraction systems.

2.4. Extracted Water Module

The WECS II model assumes that water will be extracted from the sequestration formation. This extraction may be used to manage pressure build up, control CO_2 plume migration, and provide a means to offset increased power plant water demands associated with carbon capture and sequestration. The distance between the wells and the representative power plant can change according to user input. The default distance is set to shorter distances to help minimize the need to move extracted water long distances (and across several political boundaries) from the formation back to the power plant. Next, the module calculates the depth of sequestration. Within a 500' interval starting at 2500' to 3000', then 3000' to 3500' and so on up to 9500' to 10,000' the maximum sequestration depth was considered. If information on formation depth and thickness improves, the formation selected may at some point determine the sequestration depth without the associated well analysis.

User input options for the extracted water module are shown in Figure 10. The user inputs determine the range of water quality defined by total dissolved solids (TDS) to be targeted by the extraction wells. Total Dissolved Solids is defined in units of parts per thousand (ppt). Based on this range and the distribution of salinity in the formation, the model chooses a default extraction depth interval of 2500'−4999', 5000'−7499', or 7500'−10000' to minimize water extraction and treatment costs. The WECS II model assumes that extracting waters from any of those depth intervals can accomplish the desired pressure relief and plume management goals regardless of the depth of sequestration. Once the salinity range and extraction depth range have been selected, the model can calculate the probability of drilling a well with acceptable water quality (this probability has cost implications associated with drilling wells that cannot be used) which becomes the default, base case value. The distribution of water qualities in the formation at the given depth for useable wells then determines the average salinity expected from useable wells.

Figure 10 illustrates the assumptions used to specify how much water is actually removed from the formation with the default value being an equal volume to the volume of CO_2 injected into the formation.[ix]

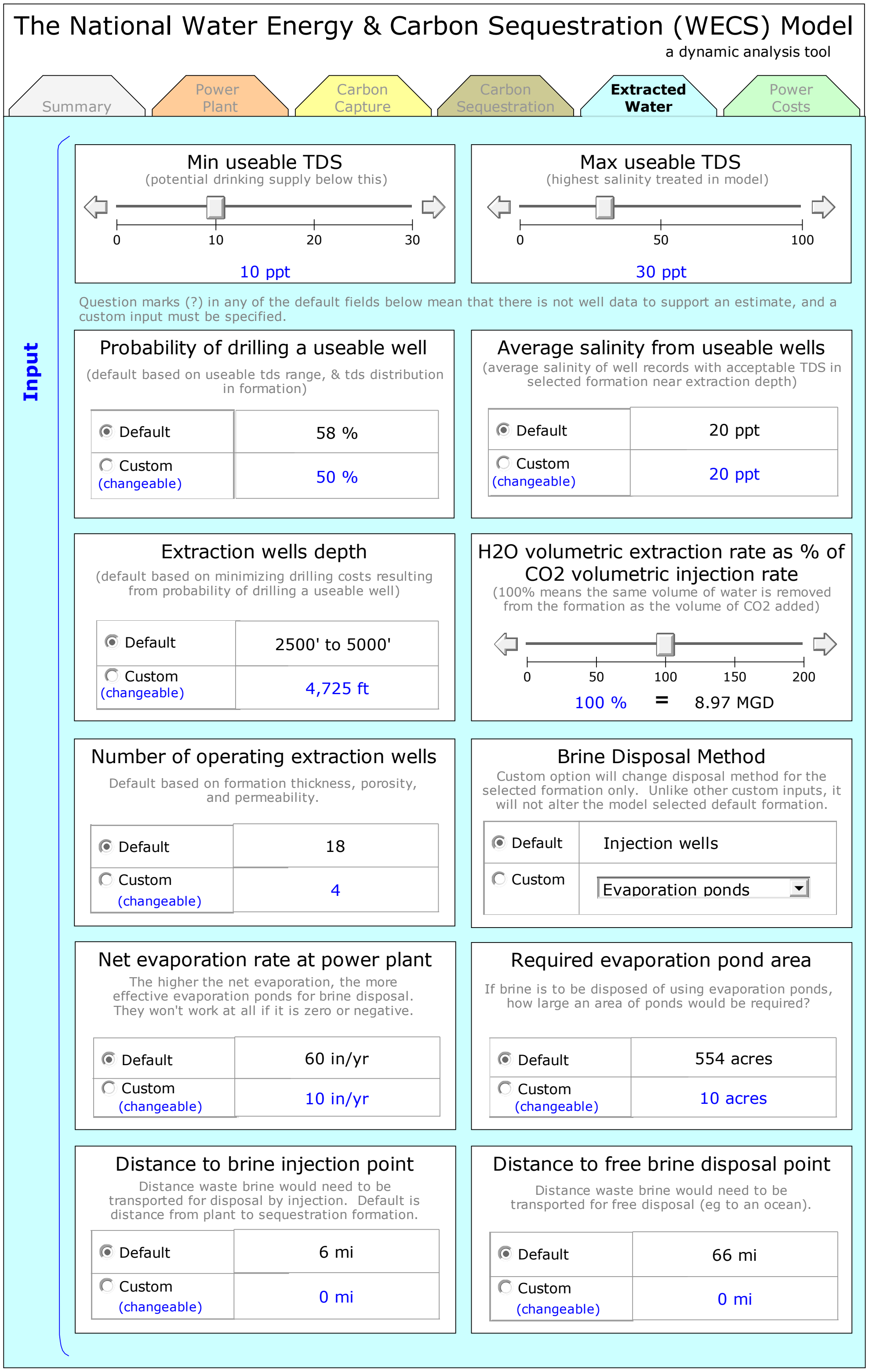


Figure 10. User interface inputs to WECS II extracted water module showing adjustable inputs. Values in blue and radio buttons or slider bars can be changed by the user.

The extracted water module also selects a least cost default brine disposal method based on the least cost method for a particular power plant. The brine disposal methods currently considered are evaporation ponds, delivery to the ocean, and injection back into the source formation, with a brine concentrator option planned for the next model iteration. The relative cost of these disposal methods varies with net evaporation at the power plant, distance of the plant to the ocean, and distance between the plant and the saline formation being utilized that can all be customized if desired.

Using the information and results of the extracted water model, several select variables including a histogram of water quality in well records associated with the geologic formation in the target extraction depth range are displayed as output in the user interface of the extracted water module as shown in Figure 11.

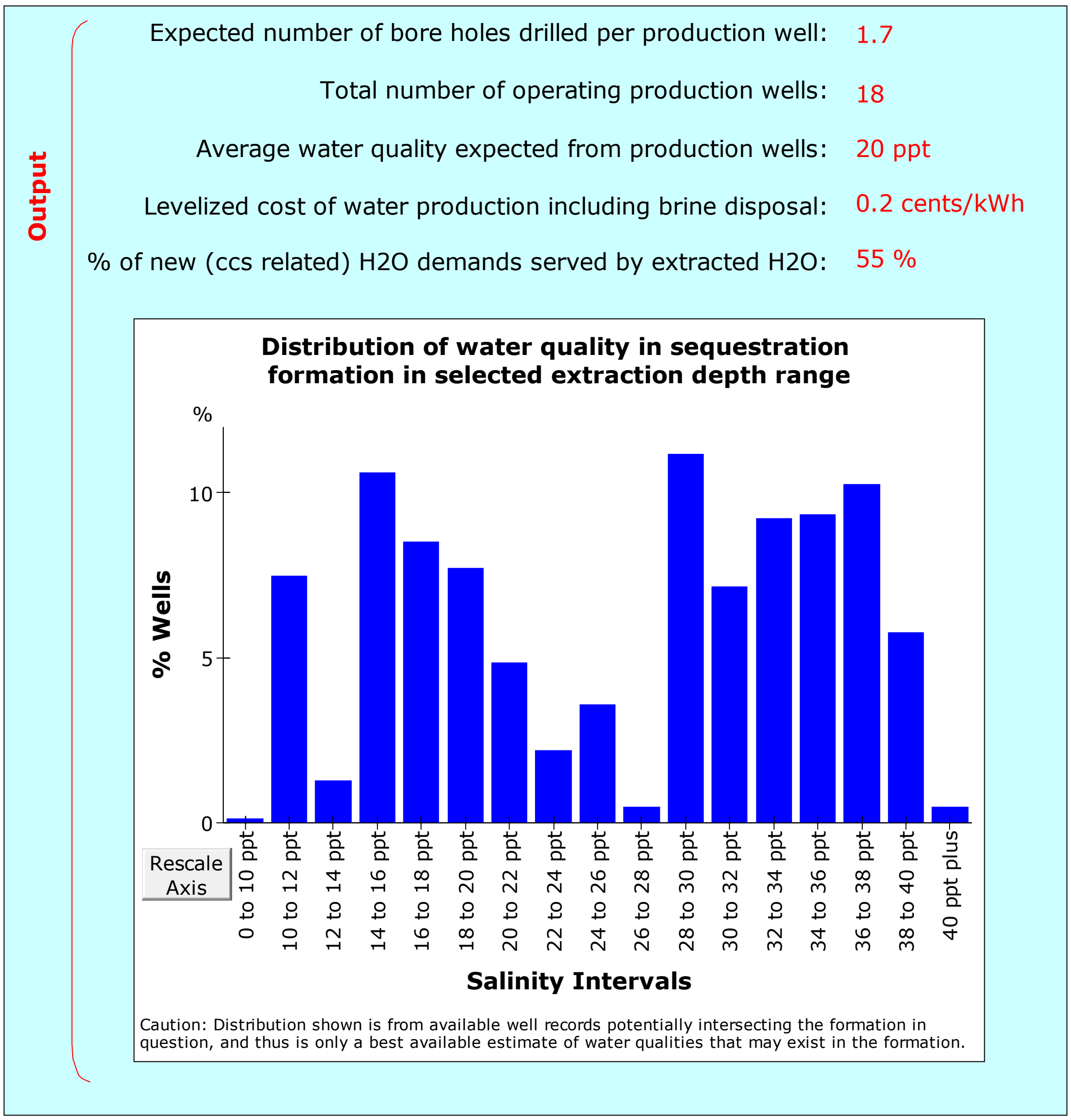


Figure 11. User interface outputs from the WECS II extracted water module.

The base case assumptions for WECS II specify that the well capital costs are $375 per foot of depth and million gallons per day (MGD) of extraction(2000 $US). For example, a well 1000 feet deep extracting 10 MGD would cost $375*1000*10 = $3.75 million (2000 $US). This methodology follows that used in the original WECS model (Kobos et al., 2008a,b; 2009, 2010), that also draws from NETL (2009a) and the U.S. Bureau of Reclamation Desalting Handbook (USBR, 2003). When a well is drilled that cannot be used (based on a similar probabilistic methodology outlined in the carbon sequestration well development module), WECS II assumes that 75% of the cost of a completed well is spent on drilling only, and is lost to any unusable effort. Unlike the case for the CO_2 injection wells, the water extraction well may require substantial amounts of energy to pump the water from the extraction well depth.

Finally, the model adds an additional 1.5% of capital costs as non energy related O&M. The capital cost of water pipelines (2000 $US) is calculated as $111,314 per mile plus an additional $35,761 per mile per MGD of flow building from the methodology outlined in Kobos (2008a,b; 2009, 2010). Thus a pipeline 100 miles long carrying 10 MGD would have a capital cost of $111,314*100 + $35,761*100*10, or about $47 million (2000 $US). Energy costs of the water pipeline are calculated based on the friction coefficient of the pipeline times the length of the pipeline, times the mass of the water being transported times the acceleration due to gravity divided by the efficiency of the pipeline pumps. No elevation change from the point of extraction to the treatment plant is currently incorporated. Finally, an additional 1.5% of capital costs are assumed as the non energy related O&M costs of the pipeline. Figure 11 illustrates the water treatment costs. The WECS II model assumes use of High Efficiency Reverse Osmosis (HERO™) water treatment.[x] The feed flow refers to the total amount of untreated water that enters the treatment plant. The plant capacity on the other hand is the design capacity of treated water that the plant can produce. The capital cost of the treatment plant is calculated as the sum of two components, one for piping infrastructure, and one for the treatment related infrastructure. The default values for these in 2004 dollars are $779,931 per MGD feed flow for the piping, and approximately $3.5 million per MGD feed flow for the treatment. Annual labor costs are calculated as $171,778 per year (2000 $US) per gallon per minute of plant capacity multiplied by the plant capacity raised to the power of 0.2322. Annual energy requirements for water treatment are calculated as 2.41 kWh/1000 gallons of treated water plus 0.6 kWh/1000 gallons of treated water/ ppt of treated water extracted.

2.5. Power Cost Module

The power cost module uses the results of the power plant, water extraction, and carbon capture modules to calculate the least cost formation for sequestration and water extraction. It also calculates changes to LCOE based on capital and operation and maintenance costs associated with carbon capture and use of the selected formation for sequestration and water extraction.[xi]

WECS II assumes amine scrubbing technology for all plant types with the exception of IGCC, which are assumed to use Selexol technology (NETL, 2007a). This approach is based on costs of new IGCC plants, and may underestimate costs for CO_2 capture in a retrofit situation. A method based on retrofit costs should be developed when retrofit specific data becomes available for this particular situation. The Selexol equations are shown in the last 3 data rows of Table 7, and the user interface of the power cost module in Figure 12. An interesting insight to highlight is the capital costs and the combined O&M costs are substantially smaller per mass of CO_2 captured for the Selexol processes than for the amine based processes. This difference suggests that existing IGCC plants represent initially the more cost-effective options compared to other technology configurations for carbon capture retrofits.

Cost Type	Equation (2006 $US)	R^2
Amine Capital	CCost[$1000] = 839.59*$CO_2$Captured[tonne/hr] + 119453	0.98
Amine VO&M	VO&M[$1000/yr] = 46.183*$CO_2$Captured[tonne/hr] + 1838.6	1
Amine FO&M	FO&M[$1000/yr] = 2.6896*$CO_2$Captured[tonne/hr] + 1556.9	1
Selexol Capital	CCost[$1000] = 361.8*$CO_2$Captured[tonne/hr]	N/A
Selexol VO&M	VO&M[$1000/yr] = (3.1+153*CoalCost[$1000/ton])*$CO_2$Captured[tonne/hr]	N/A
Selexol FO&M	FO&M[$1000/yr] = 5*$CO_2$Captured[tonne/hr]	N/A

Table 7. Equations relating capital costs, variable operations and maintenance (VO&M) costs, and fixed operations and maintenance (FO&M) costs to the amount of carbon captures using amine technologies. The goodness of fit (R^2) parameter refers only to the fit of the amine equations to 4 estimated points from one report (NETL, 2007b) on one pulverized coal unit, and not necessarily to the overall extendibility of the initial equation results beyond the representative technologies.

The parasitic energy losses are specified in the CO_2 capture module. The underlying default equations for the cost of CO_2 transport and sequestration are based on Ogden (2002), but may be adjusted to custom input levels as desired. The parameters used to calculate the well costs also follow those outlined by Ogden (2002).[xii]

The current model version assumes that the potential energy of the CO_2 going down an injection well is sufficient to preclude the need for additional energy to actively pump the CO_2 down into the formation. As a result, no additional energy costs are added to the injection well costs. This may be changed in subsequent scenarios.

It is important to note that the WECS II model currently has no cost associated with buying or leasing subsurface pore-space in the formation for storage of CO_2. The legal ownership issues associated with pore-space ownership are still being considered. As information becomes available, these costs may be added to the model.

Additional parameters relevant to the underlying economic calculations include the loan interest rate, period, expected life of the sequestration formation that help calculate the subsequent levelized costs within the LCOE. In subsequent user option pages, custom scenario options include the CO_2 pipeline metrics (length, flow rate, capital cost, O&M costs), injection well and water collection parameters (pipeline fixed cost, $/km cost, water flow rate, well pump efficiency, water well O&M) and water transport cost parameters (pipeline base cost, marginal cost, friction coefficient, pump efficiency). The water treatment module parameter inputs include the initial capital costs (HERO™ system, labor, electricity use, O&M) and the concentrated brine disposal costs (evaporation ponds, injection wells, O&M costs). All of these parameters may be adjusted to run custom scenarios. The base case options draw from the original WECS options (Kobos et al., 2008b) and ongoing model updates.

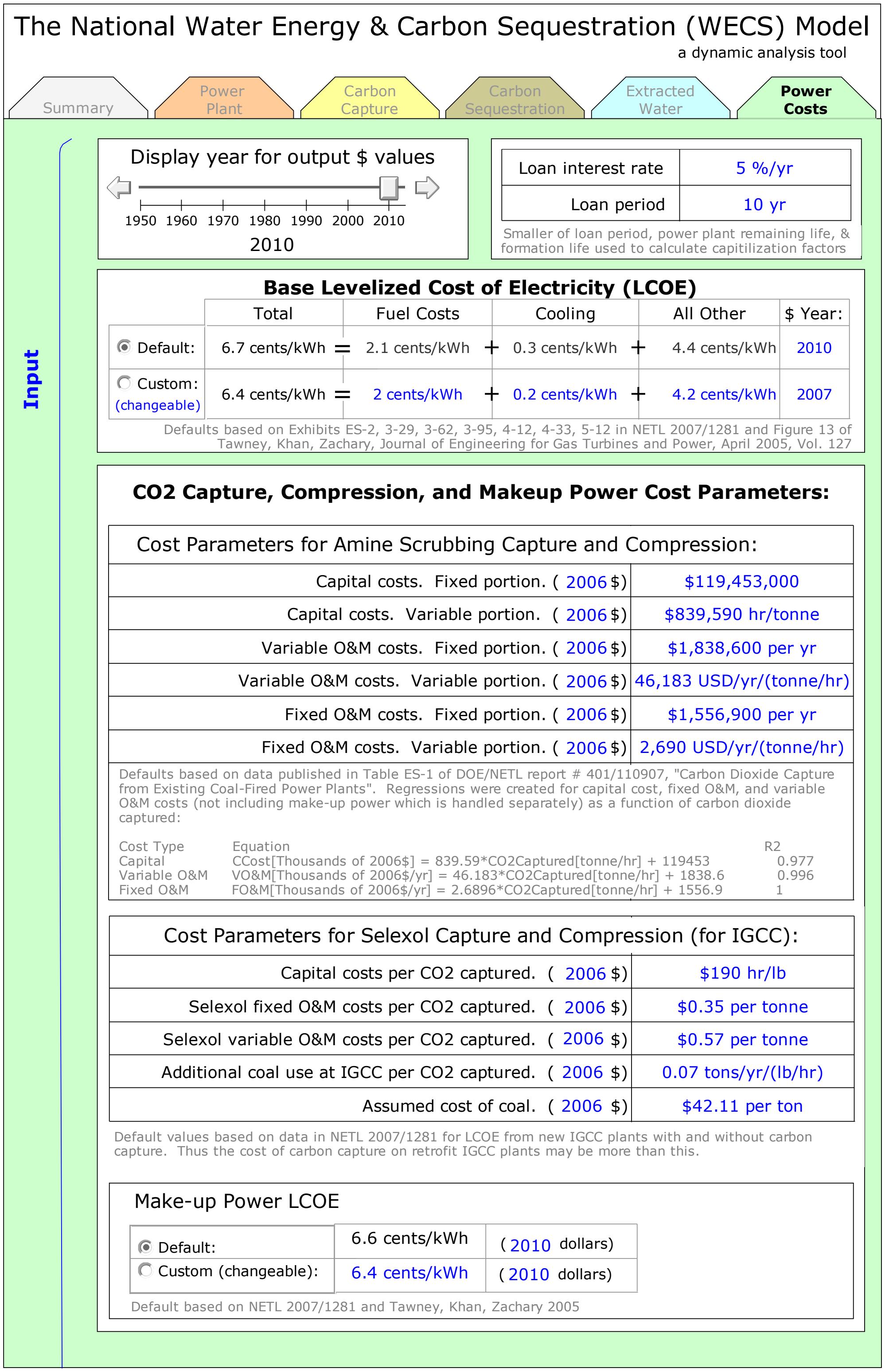


Figure 12. User interface inputs to the WECS II power costs module showing adjustable inputs. Values in blue and radio buttons or slider bars can be changed by the user.

Once the water has been treated, the resulting brine concentrate must be disposed of using three potential options: evaporation ponds, reinjection, and/or discharge to the ocean. Additional brine concentrate management technologies may be included in subsequent versions of the analysis, but the current calculations are based on those employed by the original WECS model (Kobos, et al., 2008; USBR, 2003). The flow rate of the concentrated brine pipelines will be less for ocean discharge than it was for the extracted water, so in general the pipeline costs for the brine concentrate will be less than those for the extracted water. For brine concentrate discharge to the ocean, no additional costs are added, while for reinjection, there are additional costs associated with construction of injection wells. It may be possible to use the CO_2 injection wells for brine concentrate disposal that may have benefits related to CO_2 plume management. However, for the purposes of the WECS II model at this time, it is assumed that new injection wells will be required for the brine concentrate. Once the annualized costs associated with CO_2 capture, compression, sequestration, and extracted water use have been calculated, they can also be expressed in terms of the levelized cost of electricity.

3. WECS II Summary Interface

The General Summary illustrated in Figure 13 gives a high level summary of the base case scenario for one representative power plant amongst the hundreds throughout the United States. The reported results include the power plant capacity and type, the percentage of CO_2 being captured, the LCOE and water demand increases resulting from carbon capture, the cost of avoided CO_2 emissions, the distance between power plant and sequestration formation, the size of the sequestration formation in terms of the estimated number of years of sequestration available, and the percent of water demand increase served by the extracted water. Additional detail on the carbon capture aspects of the representative scenario include the percent of CO_2 captured, the resulting parasitic energy loss, CO_2 generation as a result of make-up power generation, the percent of this carbon that is captured, and the added water withdrawal demands associated with CO_2 capture and compression. Additionally, the model user can receive information about the formation under consideration for sequestration including location. Regional Carbon Sequestration Partnership name, geologic basin and formation names, and the estimated number of years of sequestration available are also reported for the given sequestration location. The extracted water summary returns information on the extracted water module including the rate of extraction, the treated water resource, the percent of added water demand associated with CO_2 capture and compression that is served by this resource, the target water quality, the extraction well depth, and the selected brine concentrate disposal method. The power costs summary displays information regarding the power costs module including the base LCOE, and the incremental LCOE associated with carbon capture and compression, CO_2 transport, and water extraction and treatment, the total new LCOE, the percent increase from base that this represents, and the cost of avoided atmospheric CO_2 emissions.

The National Water Energy & Carbon Sequestration (WECS) Model

a dynamic analysis tool

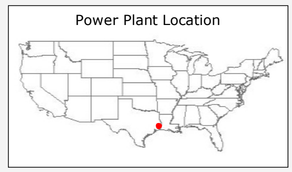
Summary | Power Plant | Carbon Capture | Carbon Sequestration | Extracted Water | Power Costs

General Summary

Power Plant Specifications	1,848 MW	PC Subcritical
% CO2 Captured	90 %	
LCOE Increase	51 %	
Cost of Avoided CO2 Emissions	$65 per tonne	
H2O Demand Increase	12.5 MGD	58 %
Distance to Sequestration Formation	6 mi	
Formation Life For This CO2 Only	73,000 yr	
% H2O Demand Increase Served	60 %	

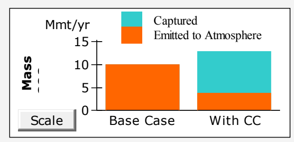
Power Plant Summary (Power Plant tab for details or to change values.)

Power Plant Type	Pulverized coal subcritical	
Latitude and Longitude	30°	-94°
Base Electricity Production	11.5 TWh/yr	
Base CO2 Production	9.9 Mmt/yr	
Base H2O Withdrawals	21.4 MGD	
Base H2O Consumption	6 billion gal/yr	



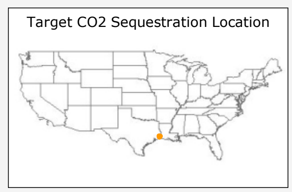
Carbon Capture (CC) Summary (Carbon Capture tab for details or to change values.)

% Base CO2 Captured	90 %
Parasitic Energy Loss	30 %
Make-Up-Power (MUP) CO2 Production	2.8 Mmt/yr
% MUP CO2 Captured	0 %
MUP and CC H2O Withdrawals	12.5 MGD



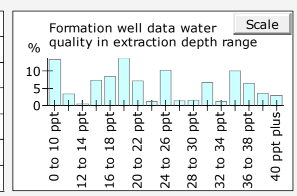
Carbon Sequestration (CS) Summary (Carbon Sequestration tab for details or to change.)

CO2 To Be Sequestered	8.9 Mmt/yr	
Target Sink Centroid Lat-Long	29°59'35"	-93°53'58"
Power Plant to Sink (centroid) Distance	6 mi	
Target Sink Partnership	SECARB	
Target Sink Basin Name	Gulf Coast	
Target Sink Formation Name	Eocene Sand	
Sink Life for this CO2 only	73,000 yr	



Extracted Water Summary (Extracted Water tab for details or to change values.)

Rate of Water Extraction	10.1 MGD
Treated Water Stream	7.6 MGD
% CCS Related Water Demand Served	60 %
Extracted Water Target Quality	10 ppt to 30 ppt
Number of Extraction Wells	21
Extraction Well Depth Range	2500' to 5000'
Brine Disposal Method	Reinjection



Power Costs Summary (2010 $) (Power Costs tab for details or to change values.)

Base Electricity Levelized Cost of Energy (LCOE)	6.7 cents/kWh
CO2 Capture & Compression Additions to LCOE	3.2 cents/kWh
CO2 Transport & Sequestration Additions to LCOE	0 cents/kWh
H2O Extraction & Treatment Additions to LCOE	0.2 cents/kWh
Total New LCOE	10.1 cents/kWh
LCOE % Increase Due to CCS	51 %
Cost of Avoided CO2 Emissions to Atmosphere	$65 per tonne

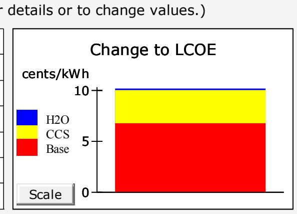


Figure 13. WECS II summary interface page.
This page combines select information from all modules to provide the important parameters associated with the scenario being evaluated by the model user.

4. Future Work Efforts

Each regional partnership was contacted to determine whether all of the site-specific attributes of their supporting data used to make the CO_2 capacity estimates as reported in the NatCarb database was being sufficiently incorporated. The analysis also builds from work developed and incorporated by Hovorka et al. (2000) characterized additional saline formation data in the U.S. In the short term, the WECS II model will focus on completing the sequestration formation database and related interface updates. The first set of scenario analyses will focus on comparing the output of this model to those of relevant, published studies as an initial validation of model function. Following this phase of analysis, the national suite of existing coal and gas fired power plants will be analyzed with WECS II. Finally, an uncertainty analysis aspect will be incorporated to bound uncertainty associated with the model's key assumptions and input data.

The WECS II model will be used to evaluate the national fleet of existing coal and gas fired electricity generators. These results will include the cost of avoided CO_2 emissions for each plant, which can be ranked, ordered, and plotted as an estimated supply curve for avoided CO_2 emissions in the early phase of carbon capture and sequestration efforts in the U.S. This would be an initial scenario because the analysis currently evaluates each power plant in isolation with no competition from other power plants for geologic resources (e.g., multiple power plants' CO_2 being stored in a single saline formation). A later phase analysis is planned that will incorporate the PDF analysis results across multiple geophysical parameters, and a temporal dimension of national carbon capture and sequestration efforts. This will allow the scenario analysis to address situations where when a plant adds CO_2 capture and sequestration, the space available for sequestration is limited to pore space that other plants have not already reserved for their own sequestration programs.

5. Conclusions

The initial results of the analysis indicate that less than 20% of all the existing complete saline formation well data may meet the working depth, salinity and formation intersecting criteria. These results were taken from examining updated NatCarb data. This finding, while just an initial result, suggests that the combined use of saline formations for CO_2 storage and extracted water use may be limited by the selection criteria chosen. A second preliminary finding of the analysis suggests that some of the necessary data required for this analysis is not present in all of the NatCarb records.

This type of analysis represents the beginning of the larger, in depth study for all existing coal and natural gas power plants and saline formations in the U.S. for the purpose of potential CO_2 storage and water reuse for supplemental cooling. Additionally, this allows for potential policy insight when understanding the difficult nature of combined potential institutional (regulatory) and physical (engineered geological sequestration and extracted water system) constraints across the United States. Finally, a representative scenario for a 1,800 MW subcritical coal fired power plant (amongst other types including supercritical coal, integrated gasification combined cycle, natural gas turbine and natural gas combined cycle) can look to existing and new carbon capture, transportation, compression and sequestration technologies along with a suite of extracting and treating technologies for water to assess the system's overall physical and economic viability. Thus, this particular plant, with 90% capture, will reduce the net emissions of CO_2 (original less the amount of energy and hence CO_2 emissions required to power the carbon capture water treatment systems) less than 90%, and its water demands will increase by approximately 50%. These systems may increase the plant's LCOE by approximately 50% or more. This representative example suggests that scaling up these CO_2 capture and sequestration technologies to many plants throughout the country could increase the water demands substantially at the regional, and possibly national level. These scenarios for all power plants and saline formations throughout U.S. can incorporate new information as it becomes available for potential new plant build out planning.

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[i] This paper draws heavily from Kobos et al., 2010 and represents the next iteration of this ongoing, multi-year project.

[ii] The correction for selected reference year is calculated based on the historic United States Gross Domestic Product Chained Price Index which is available by year from 1940 to 2014 (2009-2014 estimated) from OMB (2010).

[iii] The values are adapted from NETL (2007a), rounded to the nearest 100 pounds of CO_2 per megawatt hour electricity produced (lb/MWh). For the IGCC system, the value used is the rounded average of all 3 brands. For the gas turbine, a value of 1000 lb/MWh is assumed. Where additional information is available, user input can supersede the default values.

[iv] Gas turbines were assumed to have minimal water requirements.

[v] Exhibits 3-29, 3-62, 3-95, 4-12, 4-33, and 5-12 in the same report itemize total capital costs in such a way that the cooling system capital cost can be isolated. Exhibits 3-31, 3-64, 3-97, 4-14, 4-35, and 5-14 show variable, fixed, and fuel based operating costs.

[vi] Tawney et al. (2005) reports multiplicative factors of 0.64 and 2.7 for the relative costs of once-through and dry cooling systems respectively compared to tower cooling. These factors were multiplied by the estimates of levelized cost of tower cooling to get estimates of the levelized cost of once through and dry cooling. It was assumed that cooling pond systems would have a cost similar to once-through systems.

[vii] The data related to the potential sequestration formations is still being developed as described by NatCarb (2008 and beyond). There is a moderately high degree of uncertainty associated with the characterization of deep saline formations for a variety of reasons including observation difficulty, spatially heterogeneity, and many other factors for relatively few test cases. As a result, the data required to drive the entire WECS II model is limited in some areas. Thus, as the data is filled in, the carbon sequestration module interface will be updated as needed to allow a level of transparency between the model user and the underlying observations and assumptions related to the geologic data. To address this uncertainty, a probability distribution will be assigned to many of the model inputs and the resulting uncertainty passed through the model to generate probability distributions associated with model outputs. Thus, likely bounds to model outputs such as the supply curve for avoided CO_2 emissions can be estimated.

[viii] The authors derived a lookup table for CO_2 density based on the carbon dioxide density pressure phase diagram from Jacobs, M.A., 2005. The work of Jacobs, M.A. (2005) also builds from the works of Angus, S., Armstrong, and K.M. de Reuck, 1976 as well as Span and Wagner, 1996.

[ix] The model will likely refine this calculation using permeability, porosity, and formation thickness to estimate the number of extraction wells needed to achieve the target water extraction, and that value will populate the default option in future versions.

[x] The High Efficiency Reverse Osmosis (HERO™) system is a registered trademark of Debasish Mukhopadhyay.

[xi] The underlying model structure uses the literature or user-based input for cost figures in their respective base year dollars. From this information the model allows for this input and the subsequent results based on this data to be shown in 2010 $US by default. The results, however may be shown in the base year most relevant to the model user by adjusting the blue colored inputs for the $US.

[xii] The equation used was developed by Ogden (2002) as follows: Cost (Q,L) = $700/m x (Q/Q_o)^0.48 x (L/L_o)^0.24
where Cost is capital cost in 2001 $US, Q is the flow rate of the pipeline being built, Q_o is a reference flow rate of 16,000 tonnes per day, L is the length of the pipeline being built, and Lo is a reference length of 100 km. The 0.48 and 0.24 determine how sensitive the cost is to differences in flow rate and length from the reference values. O&M costs are assumed to be 4% of capital costs.