EASiTool - User Manual - V4.0

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Introduction

Welcome to the third version of EASiTool (Enhanced Analytical Simulation Tool), developed for CO_2 storage-capacity estimation and uncertainty quantification.

This user manual will help you install and use EASiTool.

EASiTool is intended to help users achieve a fast, reliable, science-based estimate of storage capacity for any geologic formation containing brine. EASiTool, which provides strategies for optimizing a project's net present value (NPV), offers three major features:

- An advanced, closed-form analytical solution for pressure-buildup calculations used to estimate both injectivity and reservoir-scale pressure elevation, in both closed- and open-boundary aquifers (version 1.1)
- A simple geomechanical model coupled with a base model to evaluate and avoid the possibility of fracturing reservoir rocks by injecting cold, supercritical CO_2 into hot formations, which can cause rock deformation (version 2.0)
- An active reservoir-management system throughout the brine-extraction process (version 3.0).

Disclaimer

This project is funded by the U.S. Department of Energy (DE-FE0009301).

Further Information

This software has been developed using MATLAB R2014b.

What's New?

Important changes in EASiTool V4.0:

- A new module was added to EASiTool which provide user with flexibility of placing the injectors and extractors on their own arbitrary locations. This new module can handle multiple reservoirs inside basin with arbitrary shapes.

Getting Started

This section has information on system requirements and installment of the EASiTool.

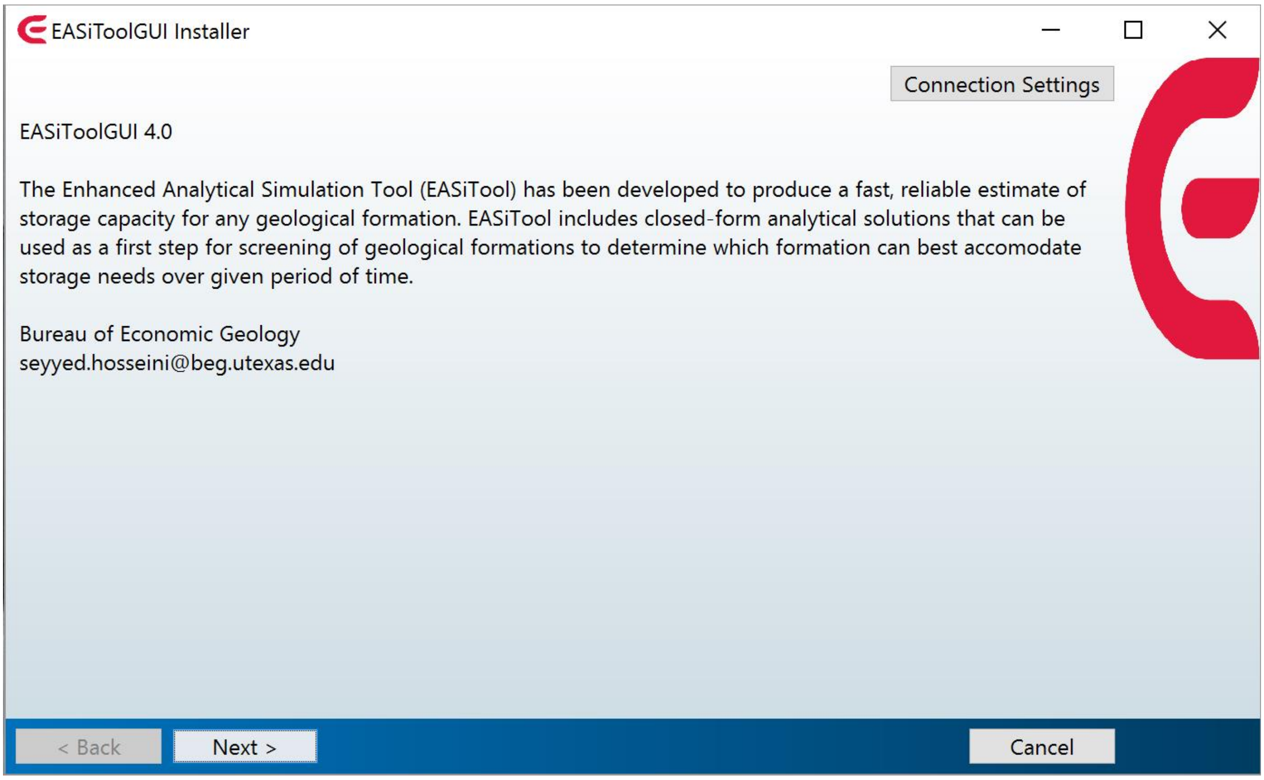
System Requirements

EASiTool is a Windows application. Windows Vista, Windows 7 (either 32-bit or 64-bit versions), Windows 8 or Windows 10 are the recommended operating systems. Windows XP (SP3) is also supported.

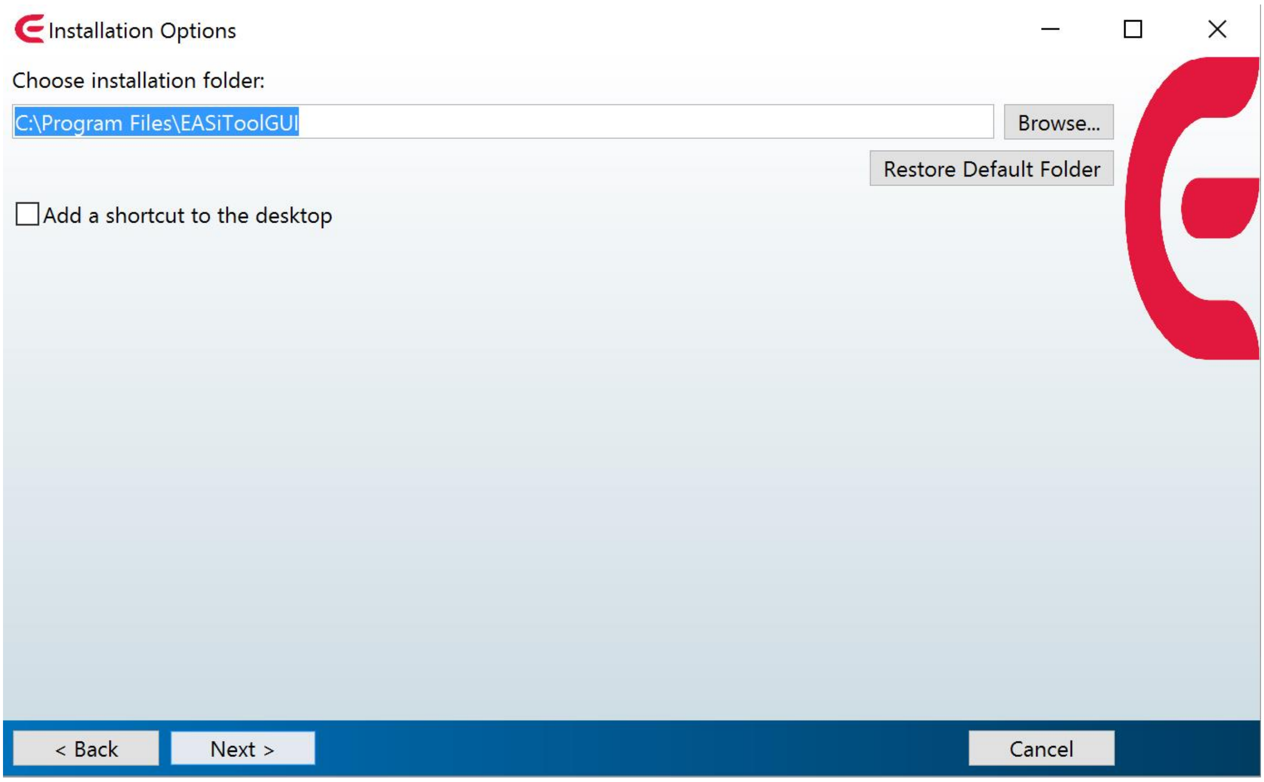
You must have administrative privileges on the system. You need a minimum of 700 MB disk space during the installation process. 16-bit color depth is required (32-bit recommended).

Installment

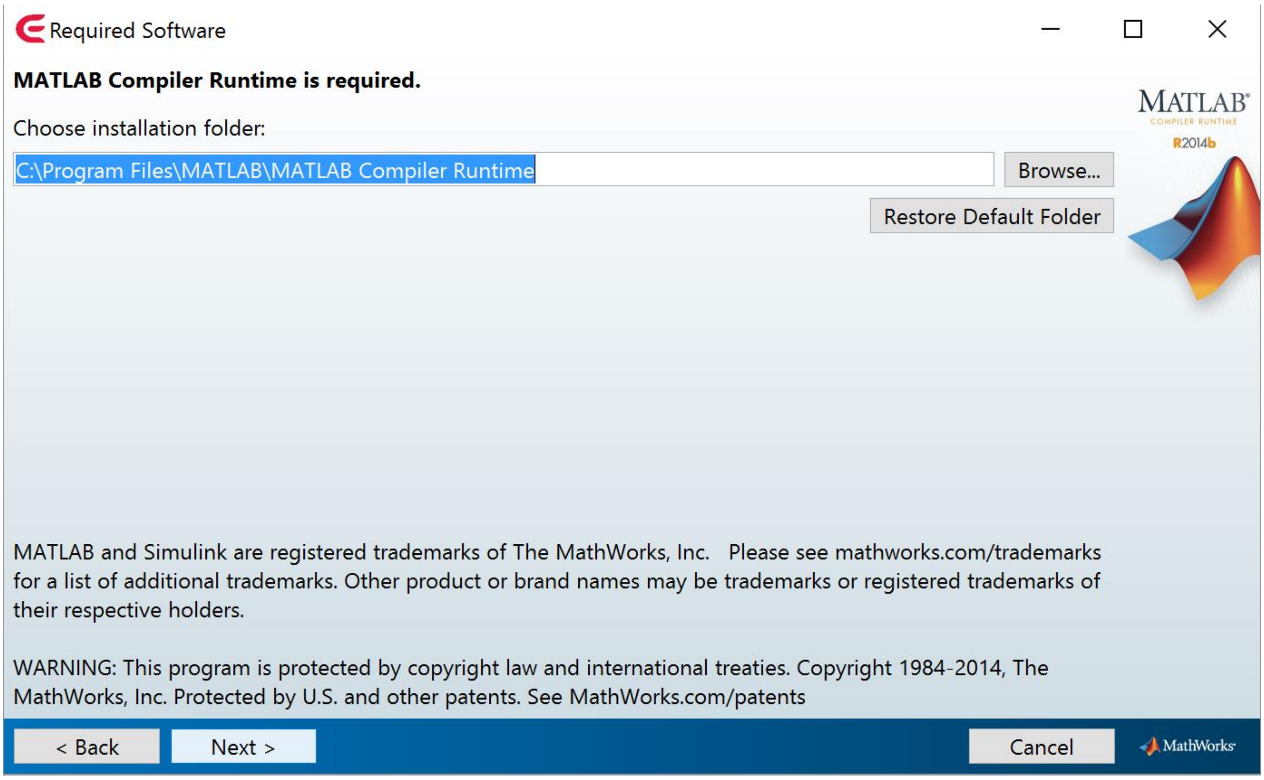
Once you download the install file from the EASiTool website, double-click it to start the installment. Click "Next" once you see the window below:



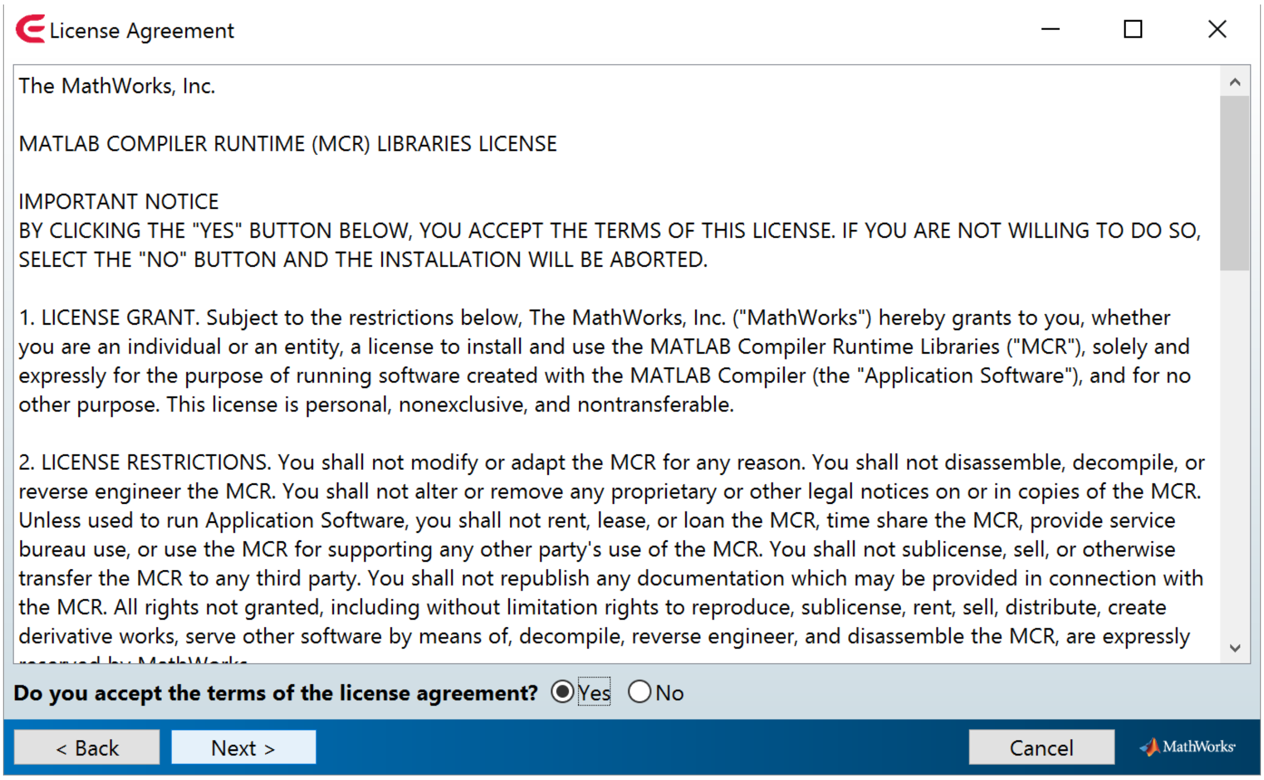
Determine the destination folder. If you don't want to change the location where the installation folder will be saved, click "Next":



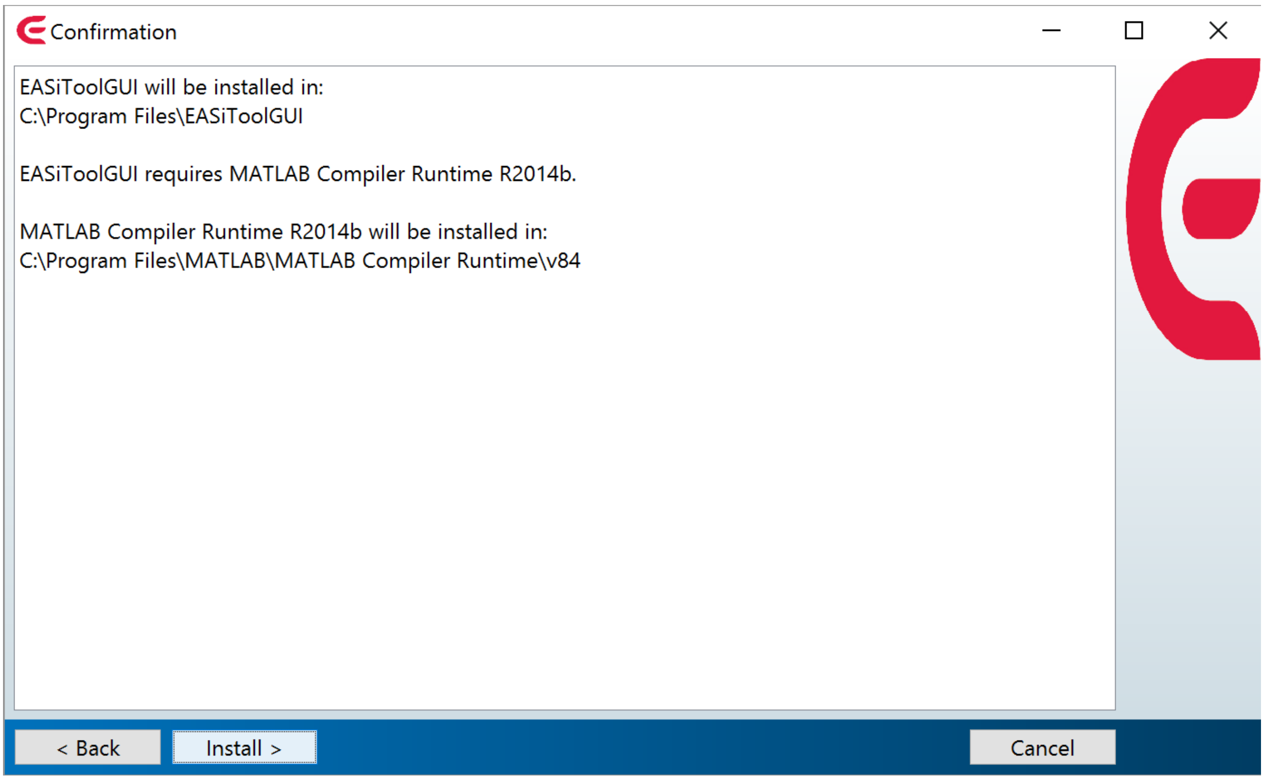
MATLAB Compiler Runtime is required. Determine the destination folder. If you don't want to change the location where the installation folder will be saved, click "Next":



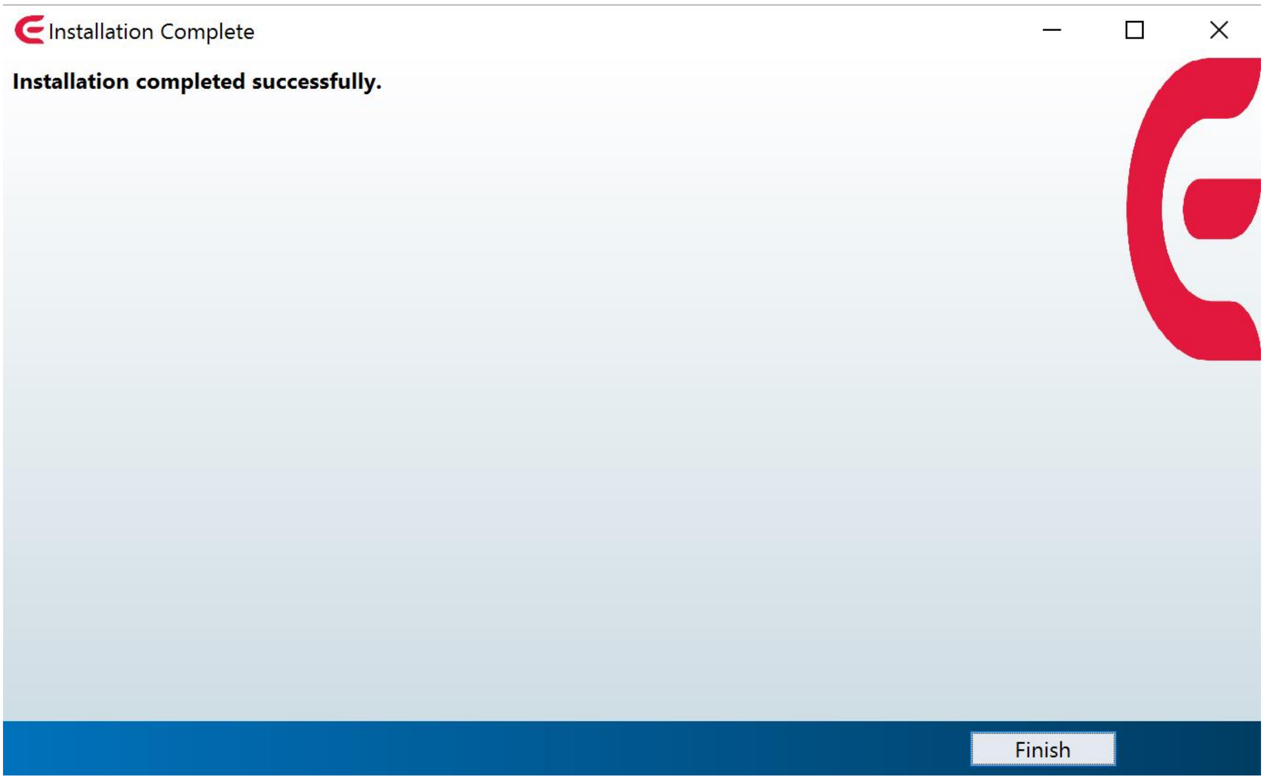
Select "Yes" to accept the terms of the license agreement. Then, click "Next":



Click "Install" to begin the installation:



Once the installation is completed (this may take a few minutes), you will see the window below. Click "Finish":



Now you are ready to use the EASiTool software by simply double clicking on the EASiTool icon.

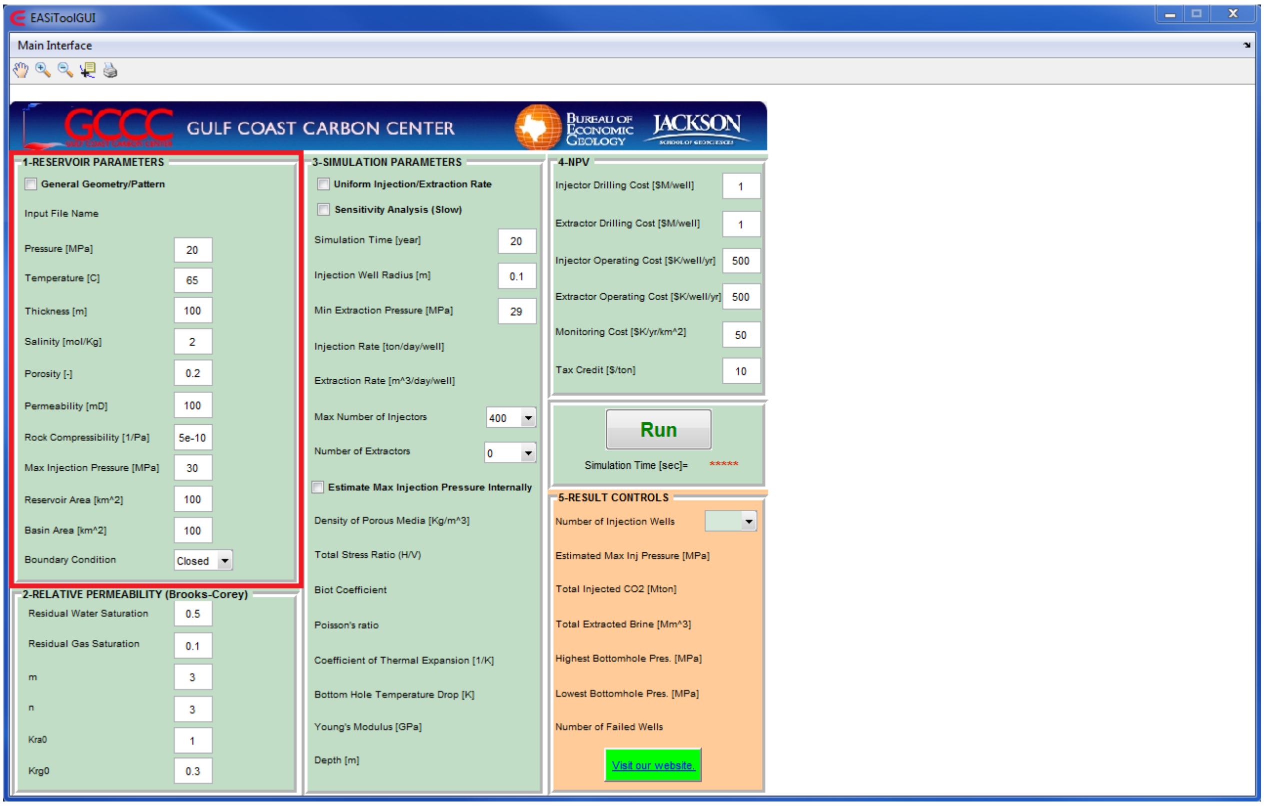
Input Parameters

Section 1 has information on the input data required to run the program.

1. Reservoir Parameters

Necessary input for reservoir parameters includes in situ pressure (MPa), temperature (C), thickness (m), salinity of the formation brine (mol/kg), porosity (-), permeability (mD), rock compressibility (1/Pa), maximum injection pressure (MPa), reservoir area (km^2), basin area (km^2), and boundary condition, as shown in Section 1 at the top left-hand side of the input screen.

> **Note**: EASiTool accepts only one set of fixed units; if the units differ from what is shown on the interface, they must be converted first.

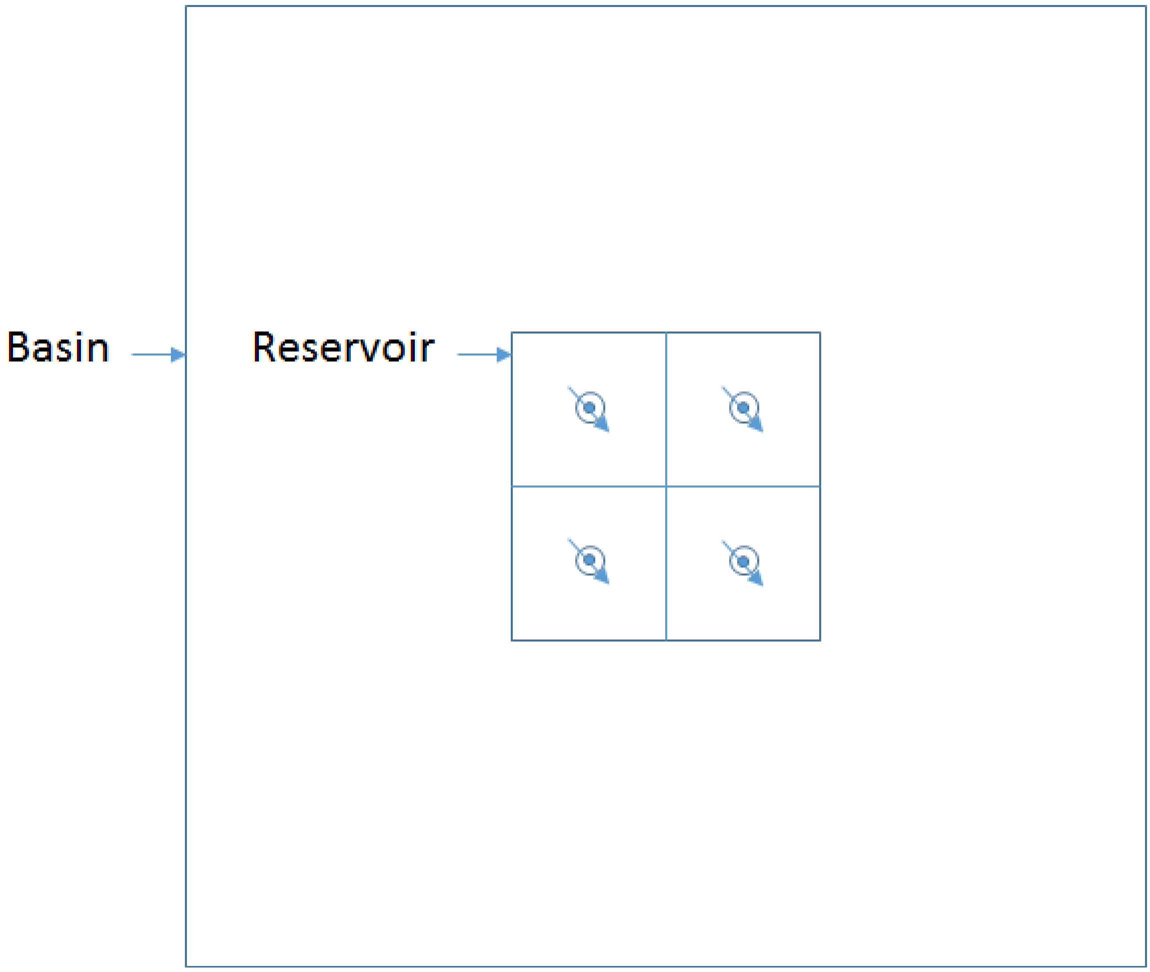


Reservoir Area (km^2): A reservoir is a part of the basin in which injectors are distributed. In the current version, we assume that reservoirs do not include detailed structures or dip angles. We also assume that reservoirs are square and placed at the center of the basins.

Basin Area (km^2): A basin is the whole areal extent of the storage formation in which the reservoir of our interest is located. In the current version, we assume that basins do not include detailed structures or dip angles. We also assume that basins are square. The basin area should be bigger or equal to the reservoir area.

Boundary Condition: Using the drop-down menu, select either an "open" or a "closed" boundary condition (In the current version of EASiTool, the selected boundary condition will be enforced on all four sides of the basin.). A reservoir can be considered open as long as the pressure change has not reached the boundaries. In an industrial-scale injection operation, the pressure effect is expected to reach the boundaries of the basin late in the injection process.

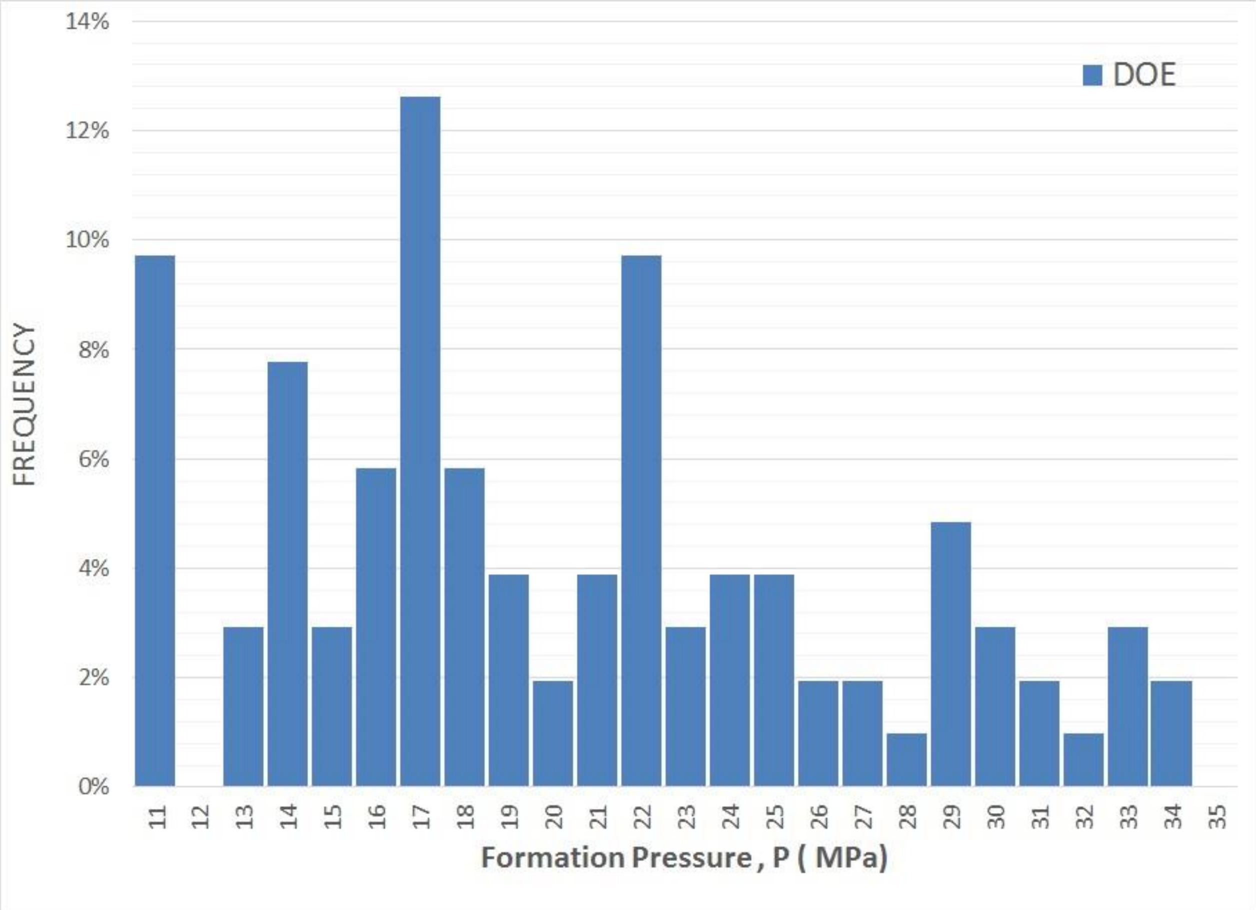
Note: EASiTool is designed to perform the calculations for multiple scenarios in which the number of wells increases from 1 to 400 in square numbers (1×1, 2×2, 3×3, 4×4, ..., 20×20). In each scenario, wells are equally spaced over the reservoir area. For example, well distribution for a 2×2 pattern is shown below:



The following table shows the range of parameters that are accepted by EASiTool:

Initial Pressure	≤ 60.0 MPa
Initial Temperature	≤ 300.0 ˚C
Thickness	≥ 0.1 m
Salinity	≥ 0.0 mol/kg and ≤ 6.0 mol/kg
Porosity	≥ 0.0 and ≤ 0.9999
Permeability	≥ 0.0 mD
Rock Compressibility	≤ 1.0E-08 1/Pa
Max Injection Pressure	> Initial Pressure
Reservoir Area	≤ Basin Area

The following six figures show the range and frequency of some reservoir parameters based on two data sets prepared by the DOE and the USGS: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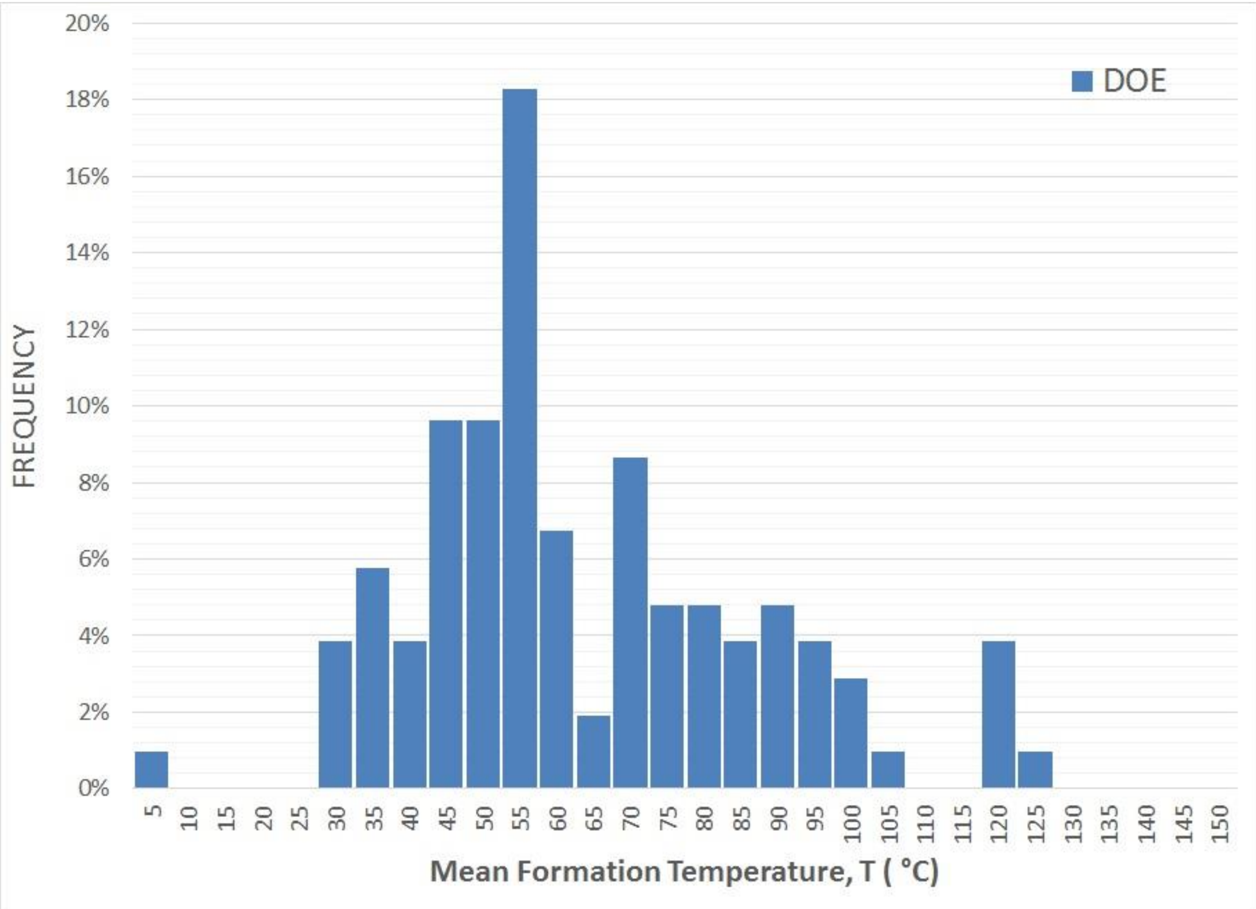
Formation Pressure , P (MPa)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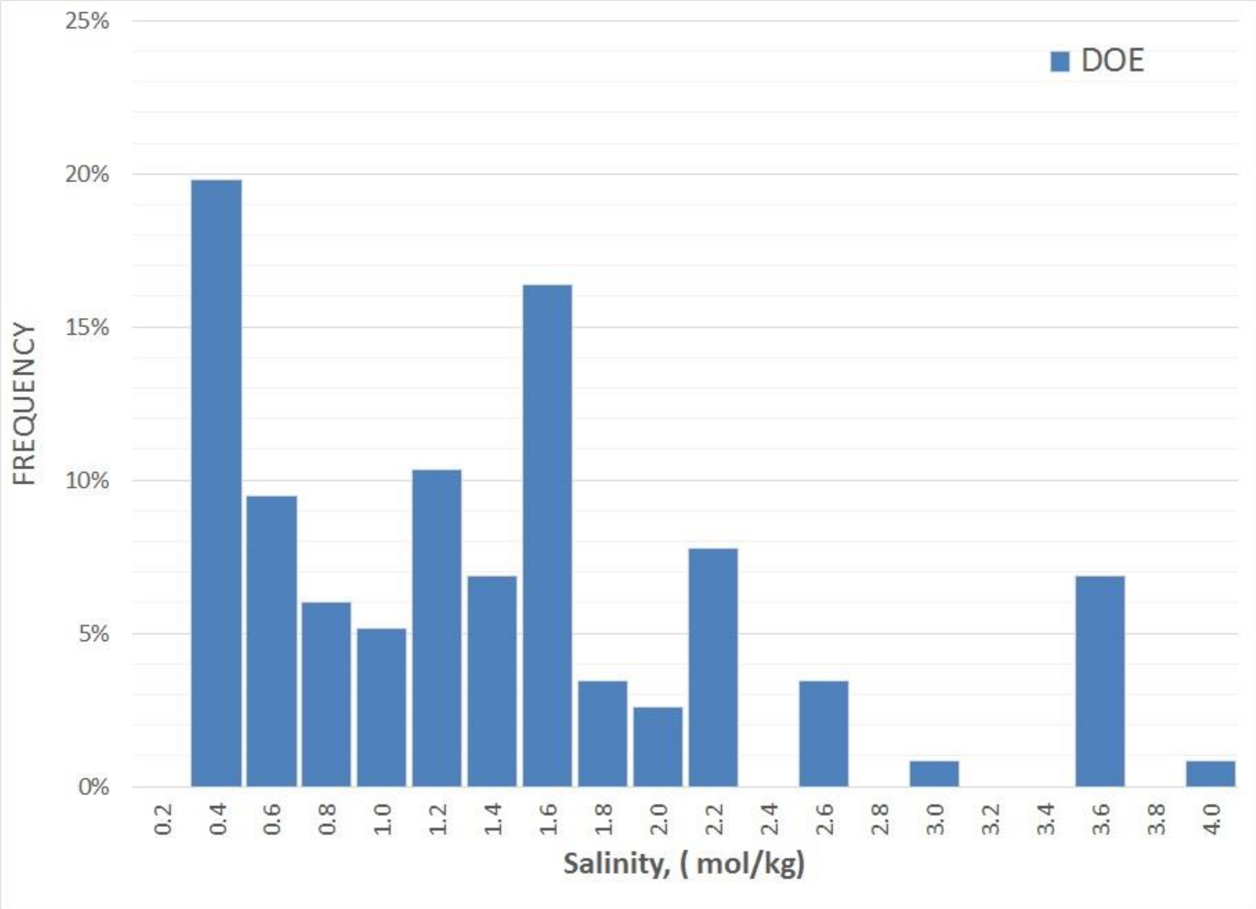
Mean Formation Temperature, T (°C)



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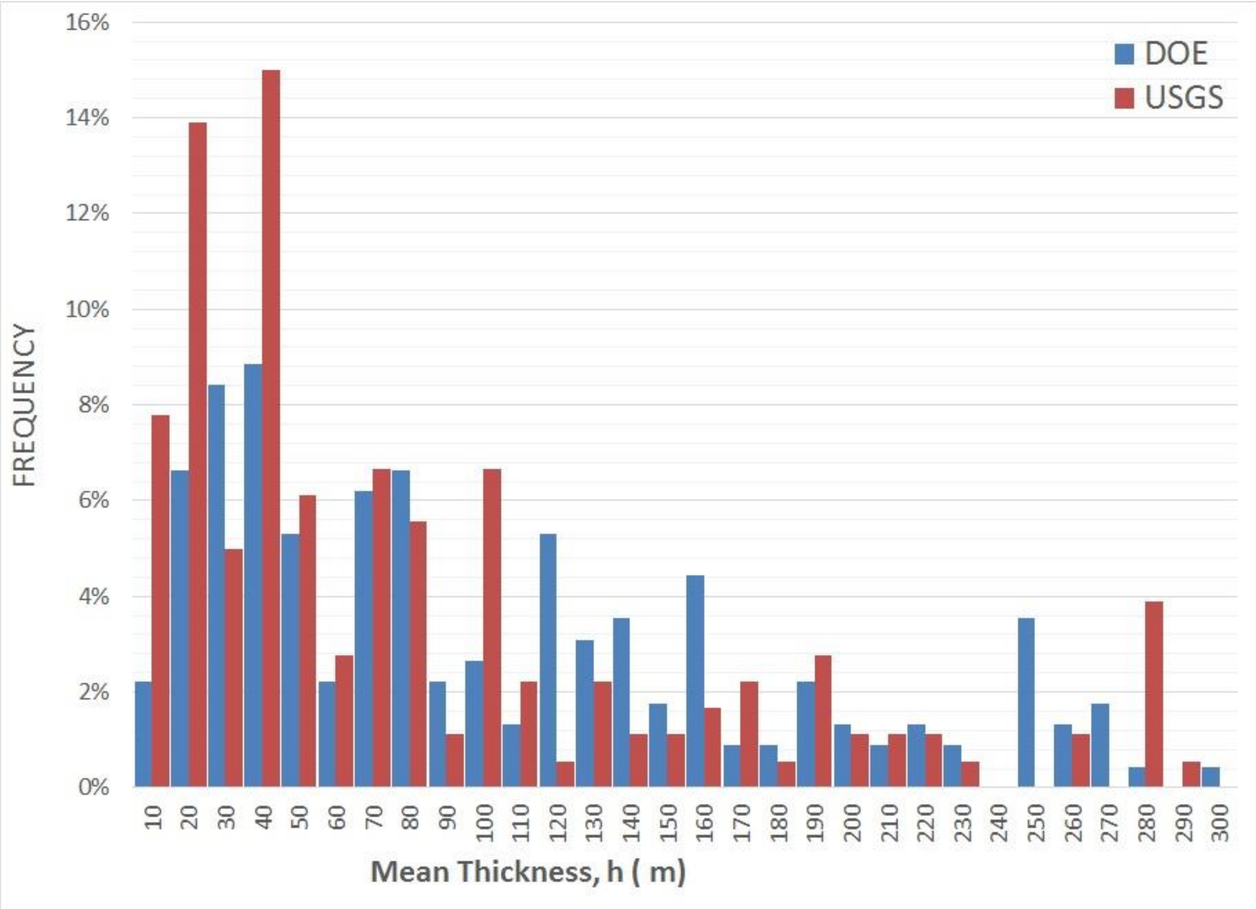
Salinity, (mol/kg)



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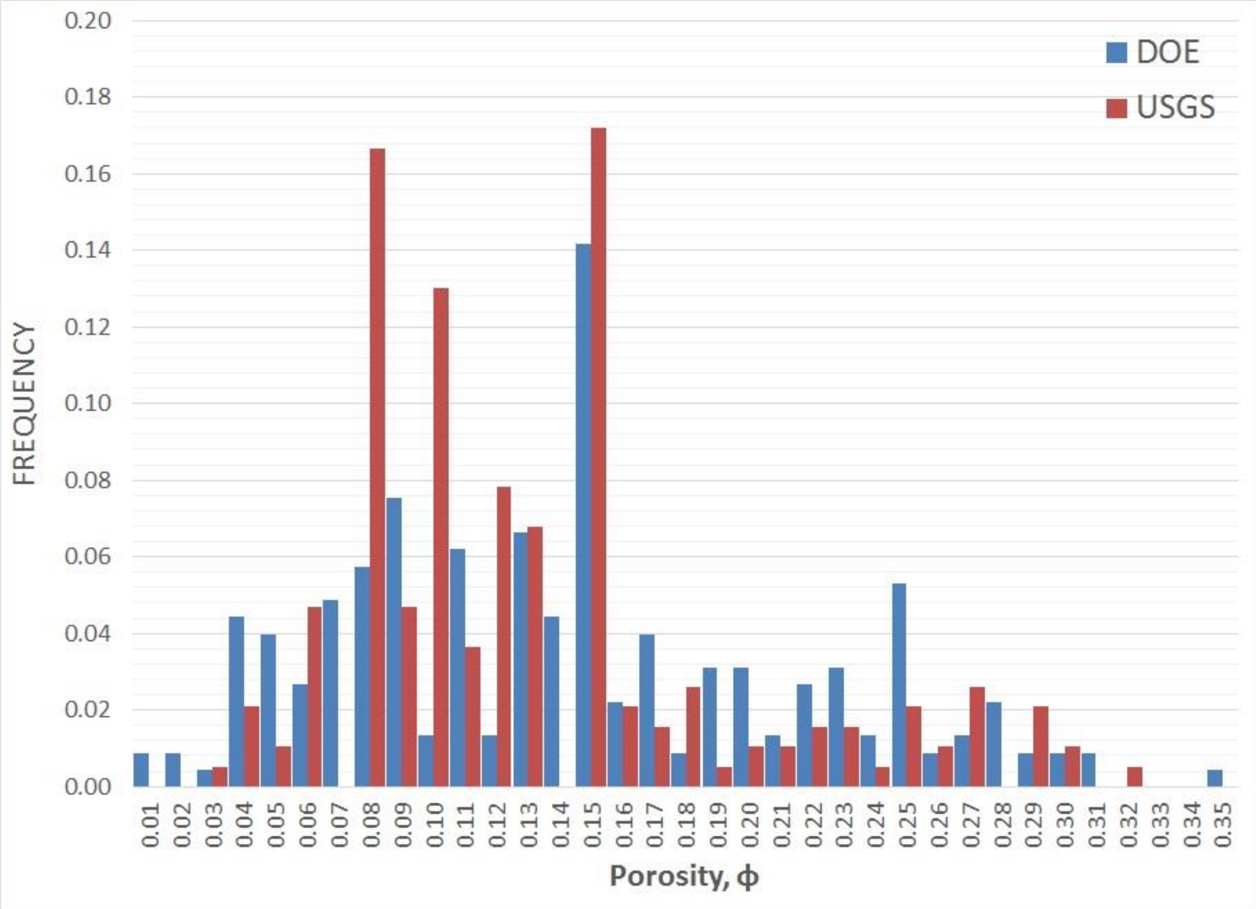
Mean Thickness, h (m)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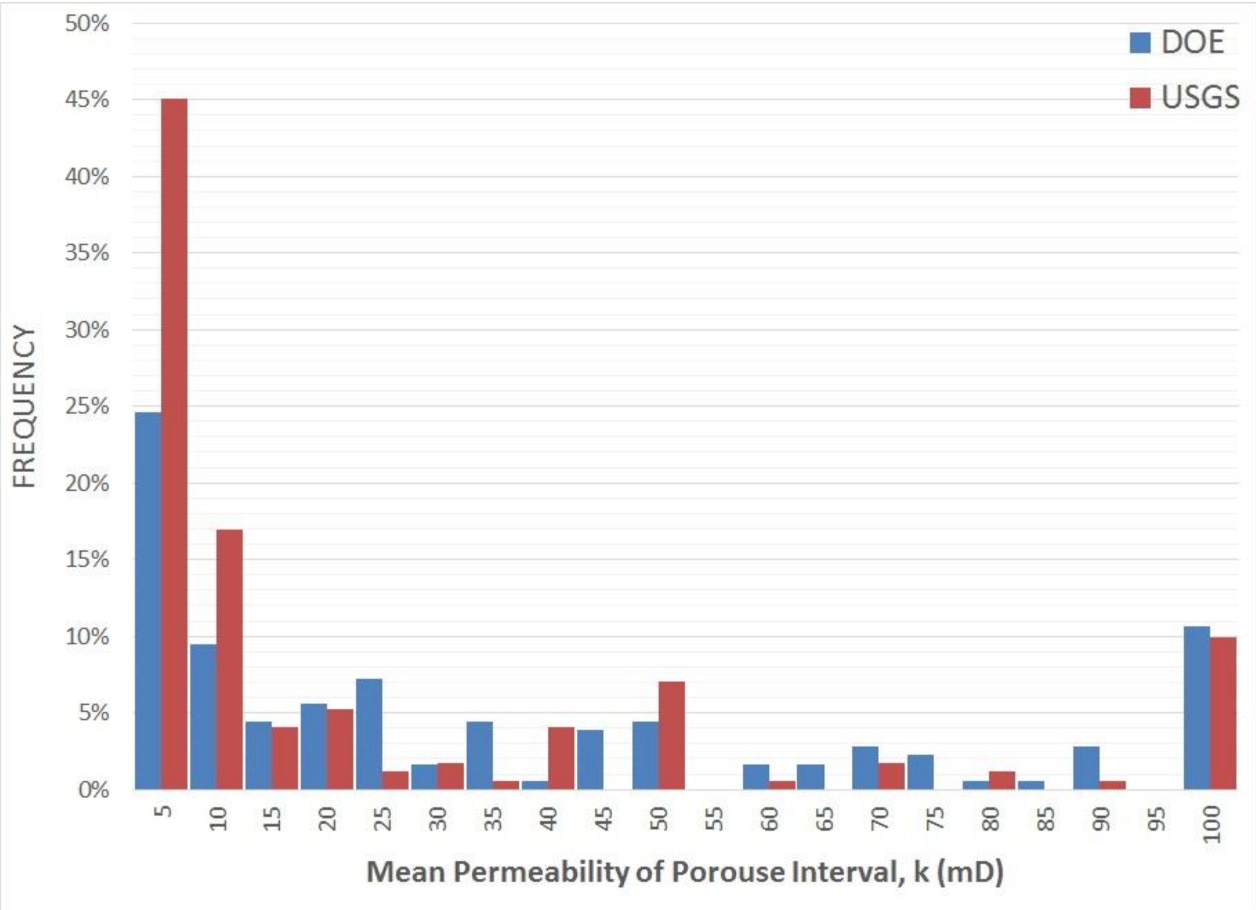
Porosity, ϕ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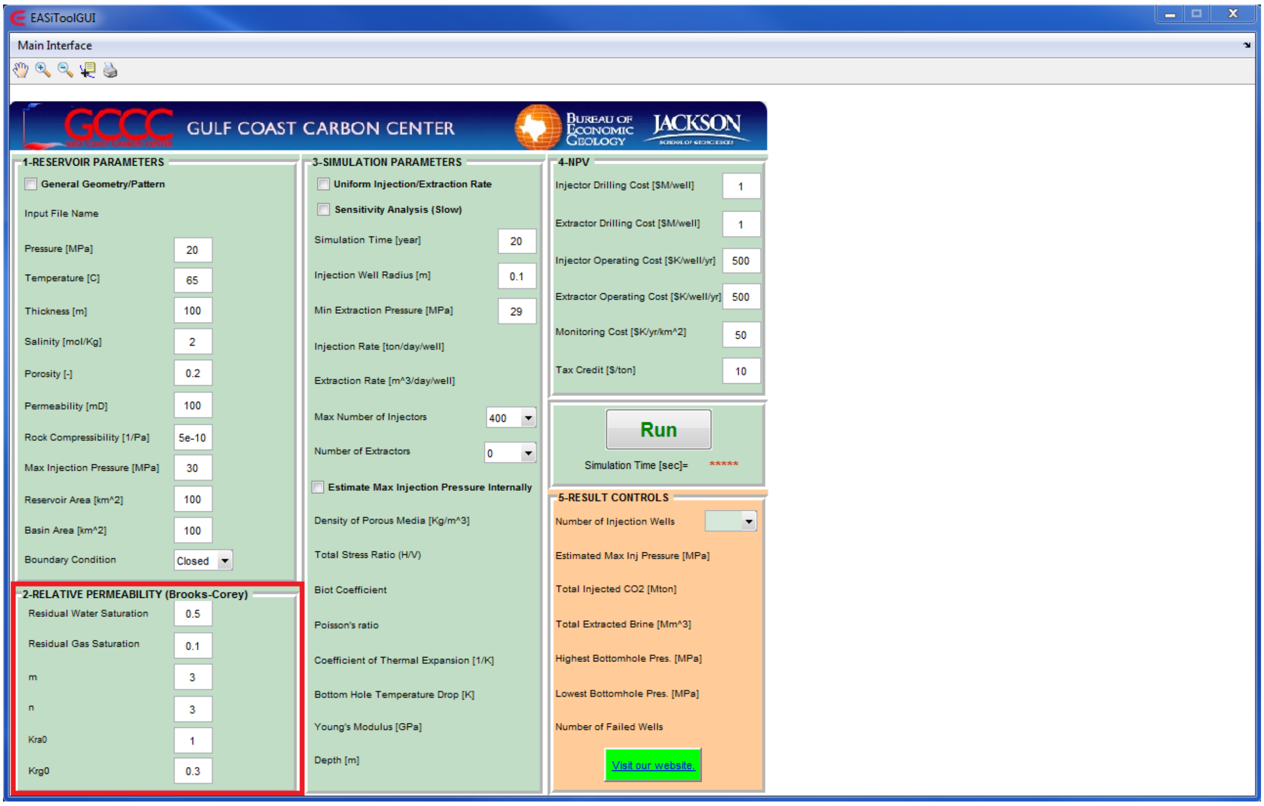
Mean Permeability of Porouse Interval, k (mD)

2. Relative Permeability Parameters

Section 2 allows the input of parameters for relative permeability, including residual water saturation (S_{ar}), critical gas saturation (S_{gc}), end-point relative permeability for aqueous phase (k_{ra0}), end-point relative permeability for gas phase (k_{rg0}), and power-law exponents for the aqueous and gas phases *m* and *n*. This section includes equations for relative permeability calculations from the Brooks-Corey model:

$$k_{ra} = \begin{cases} 0, & S_a < S_{ar} \\ k_{ra}^{\circ}\left(\dfrac{S_a - S_{ar}}{1 - S_{ar} - S_{gc}}\right)^m, & S_a > S_{ar} \end{cases}$$

$$k_{rg} = \begin{cases} 0, & S_g < S_{gc} \\ k_{rg}^{\circ}\left(\dfrac{S_g - S_{gc}}{1 - S_{ar} - S_{gc}}\right)^n, & S_g > S_{gc} \end{cases}$$



The following table shows the range of relative permeability parameters that are accepted by EASiTool:

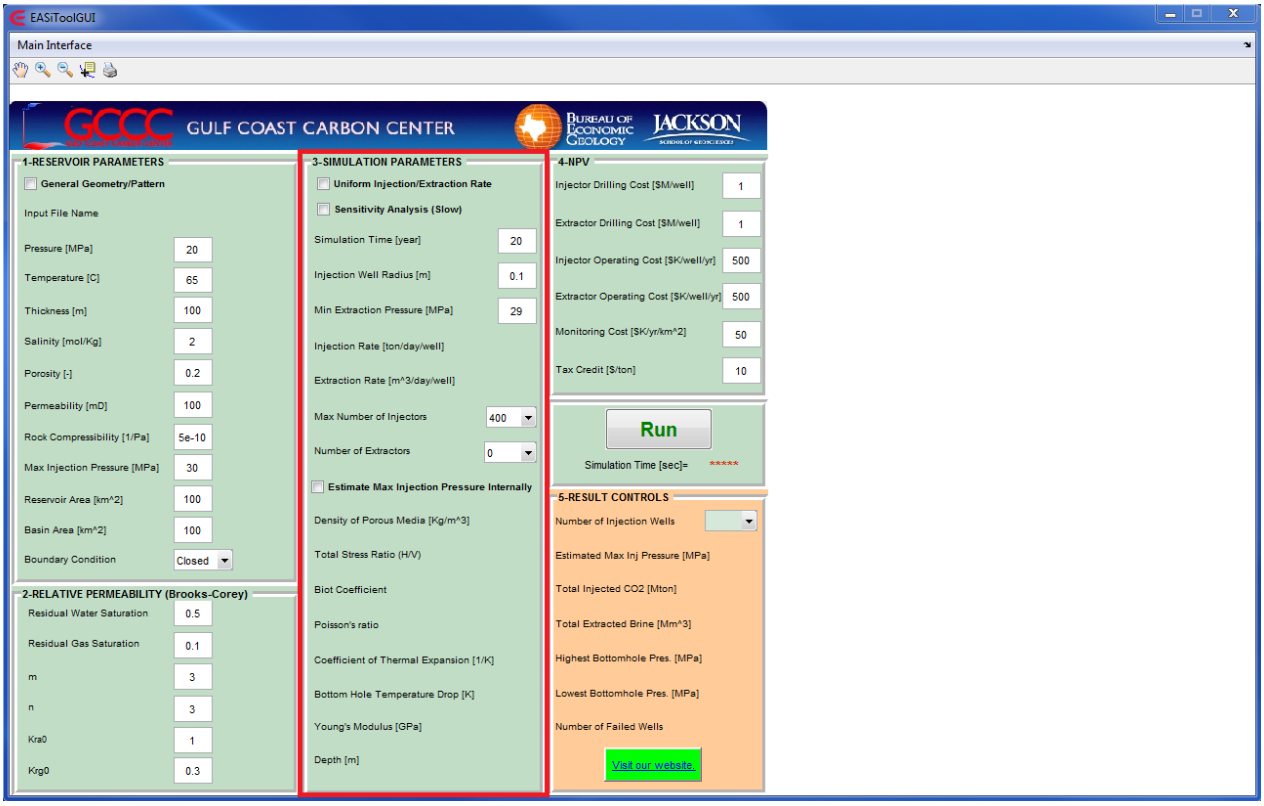
Residual water saturation, S_{ar}	≥ 0.0 and ≤ 0.9999
Residual gas saturation, S_{gr}	≥ 0.0 and ≤ 0.9999
Water relative permeability Corey exponent, *m*	≤ 1.0
Gas relative permeability Corey exponent, *n*	≤ 1.0
Water end-point relative permeability, K_{ra0}	≥ 0.0 and ≤ 1.0
Gas end-point relative permeability, K_{rg0}	≥ 0.0 and ≤ 1.0

A typical range of relative permeability parameters based on data published in literature is listed in the table below:

Residual water saturation, S_{ar}	0.2 – 0.6
Residual gas saturation, S_{gr}	0.1 – 0.35
Water relative permeability Corey exponent, m	1.5 – 4.0
Gas relative permeability Corey exponent, n	1.5 – 4.0
Water end-point relative permeability, K_{ra0}	1.0
Gas end-point relative permeability, K_{rg0}	0.1 – 0.6

3. Simulation Parameters

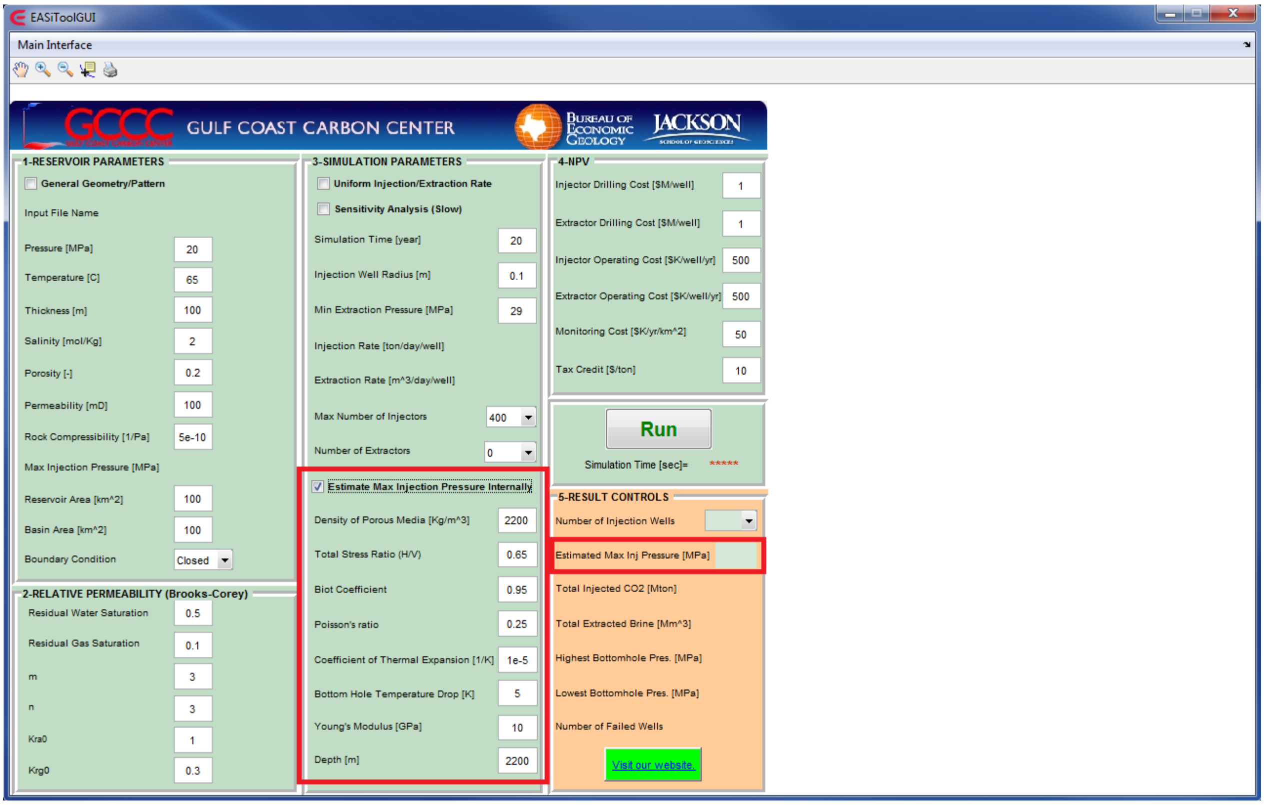
Section 3 has input parameters for simulation: simulation time (years), injection well radius (m), minimum extraction pressure (MPa), maximum number of injectors, and number of extractors.



The maximum acceptable injection well radius is 1.0 m. The minimum extraction pressure can be between 0 and 60 MPa and must be less than the maximum injection pressure. The maximum number of injectors can be set by the user on the basis of the size and properties of the aquifer. The maximum number of injectors can be varied between 1 and 400. This option gives the flexibility to avoid long simulation runs when a large number of injectors is not needed; for example, when the aquifers are small. The number of extractors should be fixed before running the simulation. The number of extractors can be 0, 4, 8, or 16.

Geomechanics Package

EASiTool can calculate the maximum allowable injection pressure internally from the reservoir properties. To include the geomechanics, check "Estimate Max Injection Pressure Internally." Next, in the new boxes, provide the following properties to estimate the maximum injection pressure:



Density of Porous Media (ρ) [kg/m³]: Density of porous media can be calculated as $\rho = \rho_d (1 - \varphi) + \varphi \rho_f$, where φ is porosity, ρ_f is fluid density, and ρ_d is dried density of the matrix.

Total Stress Ratio (H/V): The ratio of horizontal to vertical stress, K_h, is σ_h/σ_v.

Biot Coefficient (α): The effective-stress principle is of fundamental significance in soil and rock mechanics and is defined as $\sigma_{eff} = \sigma_c - \sigma_p$, where σ_c and σ_p are the total confining stress and fluid pore pressure, respectively. However, in fluid-saturated rocks, Terzaghi's principle of effective-stress may not be always valid. The Biot coefficient α (other than unity) was suggested to modify the effective-stress principle (Biot, 1941), which is given by $\sigma_{eff} = \sigma_c - \alpha \sigma_p$. The Biot coefficient α is a property of a solid constituent only. The existence of the Biot coefficient suggests that pore pressure modifies not only effective normal stresses but also effective shear stresses.

Note: $\varphi \leq \alpha \leq 1$, where φ is porosity, α will be near its upper limit for soil-like materials.

Poisson's Ratio (ν): An elastic constant that is a measure of the compressibility of material perpendicular to applied stress; that is, the ratio of latitudinal to longitudinal strain ($0 < \nu < 0.5$). Poisson's ratio can be expressed in terms of properties that can be measured in the field, including velocities of P-waves and S-waves. The Poisson's ratio for carbonate rocks is ~ 0.3, for sandstones, ~ 0.2; and for shale, above 0.3.

Coefficient of Thermal Expansion [1/K]: The coefficient of thermal expansion describes how the size of an object changes when the temperature changes. Specifically, it measures the fractional change in size per degree change in temperature at a constant pressure.

Bottom-Hole Temperature Drop [K]: The temperature difference between the formation and the injected fluid (CO_2) at the bottom of the wellbore. The fluid temperature is lower than the bottom-hole static temperature. The corresponding temperature difference causes thermal stresses in the formation and affects the maximum injection pressure.

Young's Modulus (E) [GPa]: Young's modulus, also known as the tensile modulus, modulus of elasticity, or elastic modulus, is defined as the ratio of the stress (force per unit area) along an axis to the strain (ratio of deformation over initial length) along that axis in the range of linear behavior of the material.

Depth [m]: Depth of the fluid injection (depth of perforation zone).

Estimated Max Injection Pressure [MPa]: Pressure above which the injection of fluids will cause the rock formation to fracture hydraulically. The reactivation of preexisting fracture planes via shear slip is likely to occur prior to other types of geomechanical failures in most cases. The Mohr-Coulomb shear failure criterion for the maximum pressure limit P_{max} is expressed as

$$\tau = c + (\sigma_n - \alpha P_{max})\mu,$$

where τ is shear stress, σ_n is normal stress acting on a preexisting fracture plane, c is cohesion, and μ is the coefficient of friction.

Then, the P_{max} is

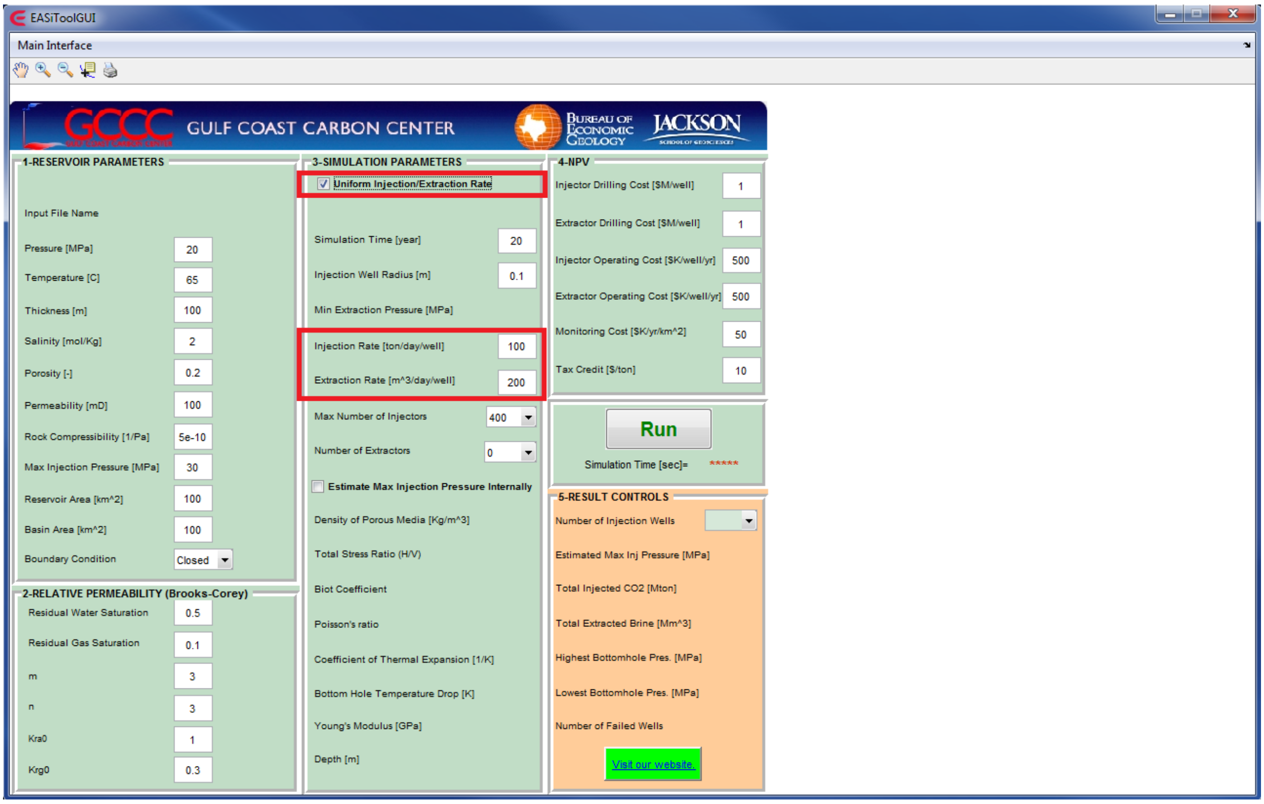
$$P_{max} = \frac{1}{\alpha}[\frac{1}{2}(\sigma_1 + \sigma_3) + \frac{1}{2}(\sigma_1 - \sigma_3)cos2\theta - \frac{1}{2}(\sigma_1 - \sigma_3)\frac{sin2\theta}{\mu}],$$

where σ_1, σ_3, and θ are major principal stress, minor principal stress, and angle with reference to minor principal stress, respectively.

The estimated maximum allowable injection pressure will be provided in the results section.

Uniform Constant-Injection/Extraction Rate

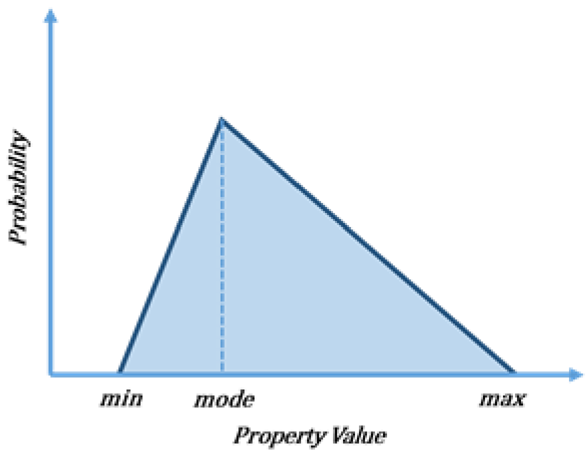
The default mode for calculation of well rates is "optimal constant-injection/extraction rate." EASiTool provides an option to calculate the final well pressures on the basis of user defined constant injection and constant extraction rates. To activate this option, check "Uniform Injection/Extraction Rate." Here, you can input the injection rate (ton/day/well) and extraction rate (m^3/day/well).



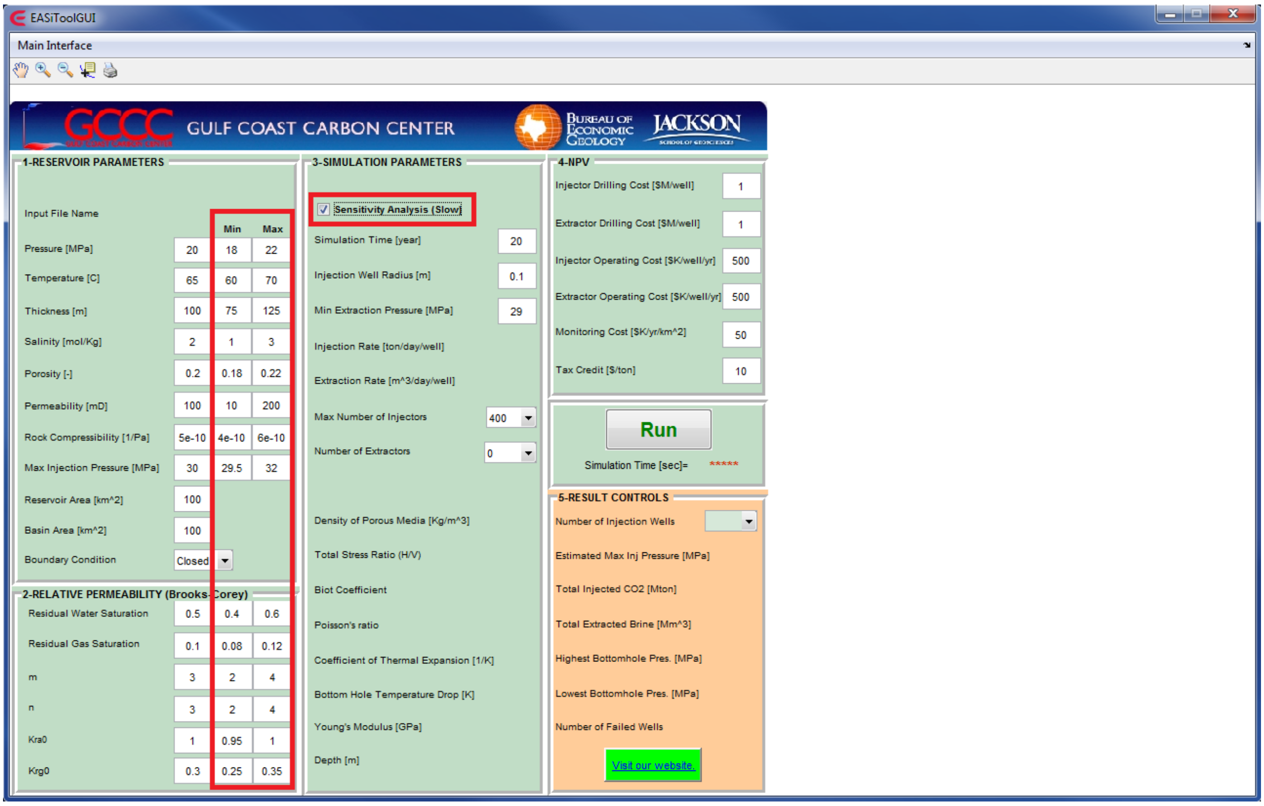
The injection rate should be between 0 and 10,000 ton/day/well. The extraction rate should be between 0 and 10,000 m^3/day/well. The injection and extraction rates are only active for the "uniform injection/extraction rate" option.

Sensitivity Analysis

EASiTool can perform a sensitivity analysis on any combination of initial reservoir pressure, temperature, thickness, salinity, porosity, permeability, rock compressibility, maximum injection pressure, and relative permeability parameters. To include the sensitivity analysis of any of these parameters, check "Sensitivity Analysis (Slow)." Then, in the new boxes, provide the minimum and maximum of the parameters for sampling. This set of input for sensitivity analysis resembles the triangular probability distribution for parameters:



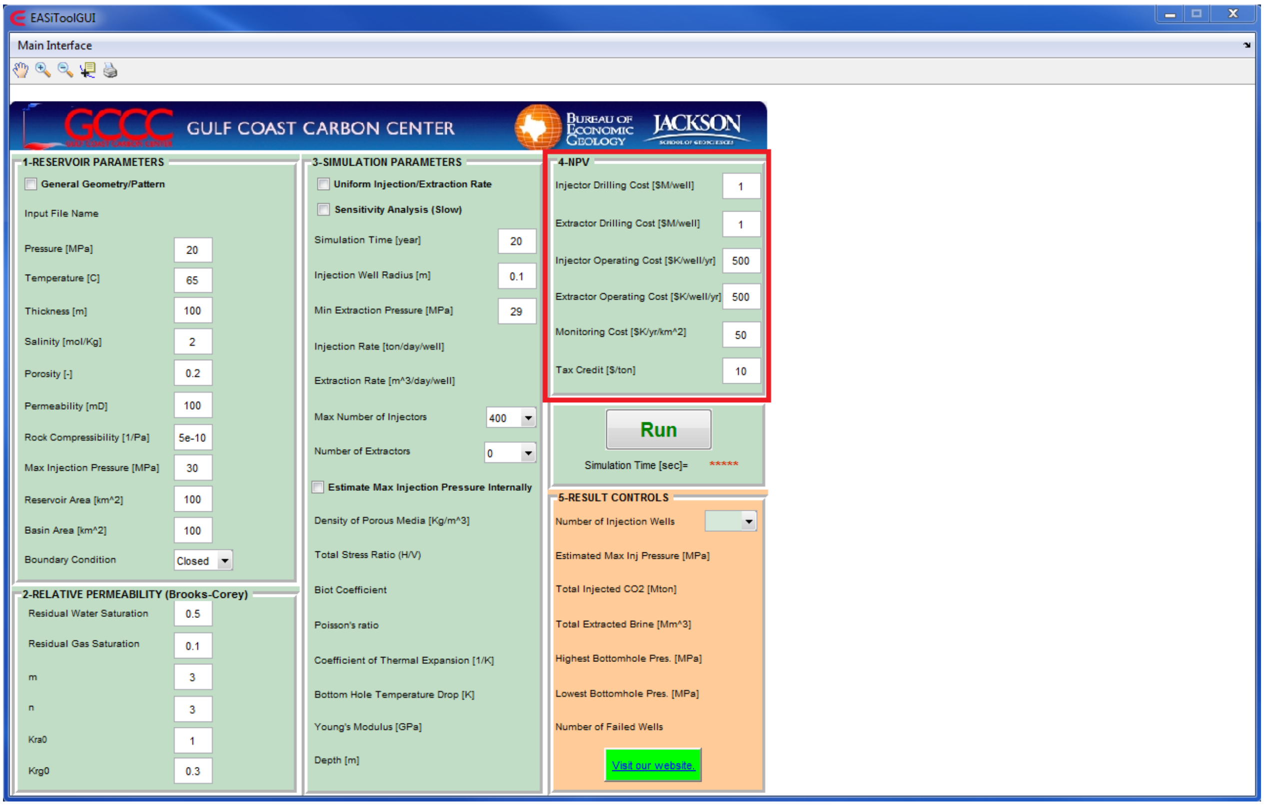
The one-parameter-at-a-time method is used for sampling in this version of EASiTool. In this method, information about the effect of a parameter is gained by varying only one parameter at a time. Because this procedure is repeated in turn for all parameters to be studied, running sensitivity analysis simulations may take a few minutes to complete.



The minimum and maximum of parameters should be in the ranges which were described in reservoir and relative permeability parameters.

4. NPV Analysis

Section 4 provides the option to conduct a very simple net present value (NPV) analysis along with the simulation. Here, you can input parameters such as injector drilling cost ($M/well), extractor drilling cost ($M/well), injector operating cost ($K/well/year), extractor operating cost ($K/well/year), monitoring cost ($K/year/km^2), and tax credit ($/ton):

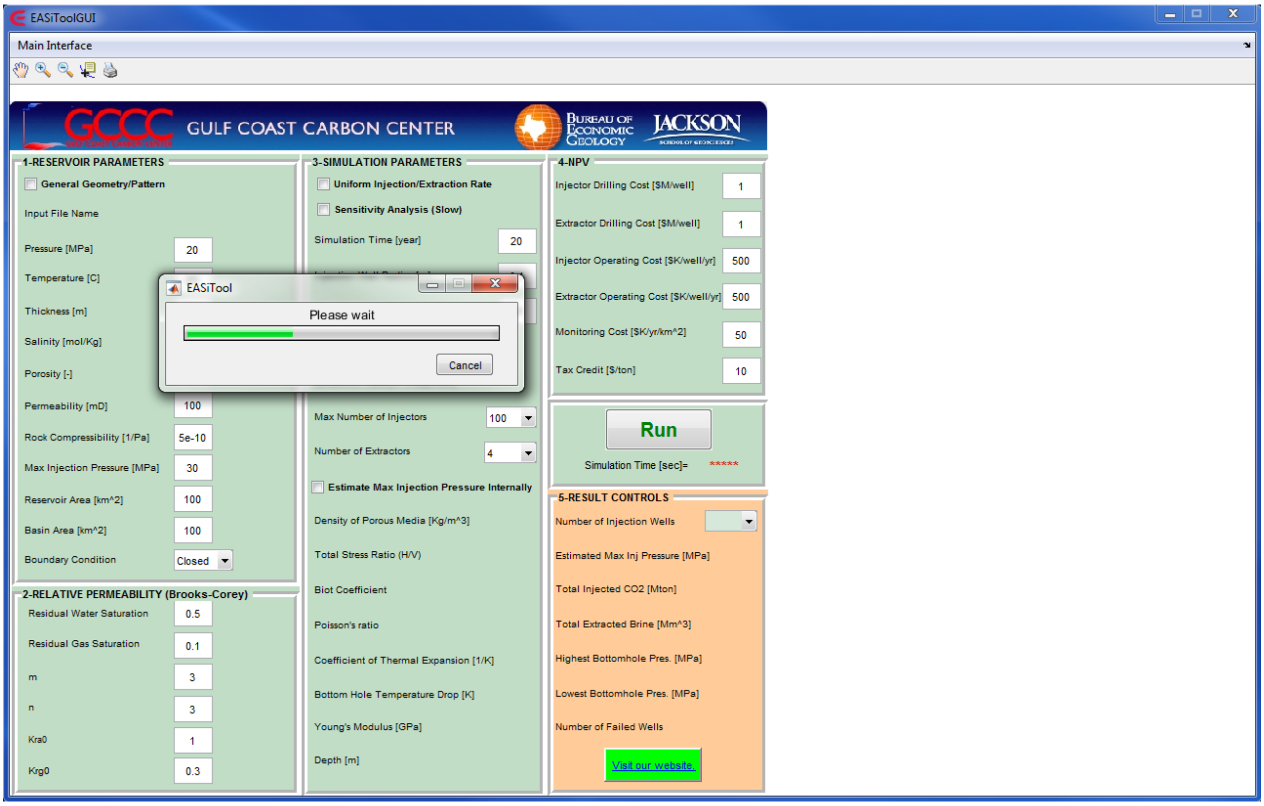


The following table shows the range of NPV parameters that are accepted by EASiTool:

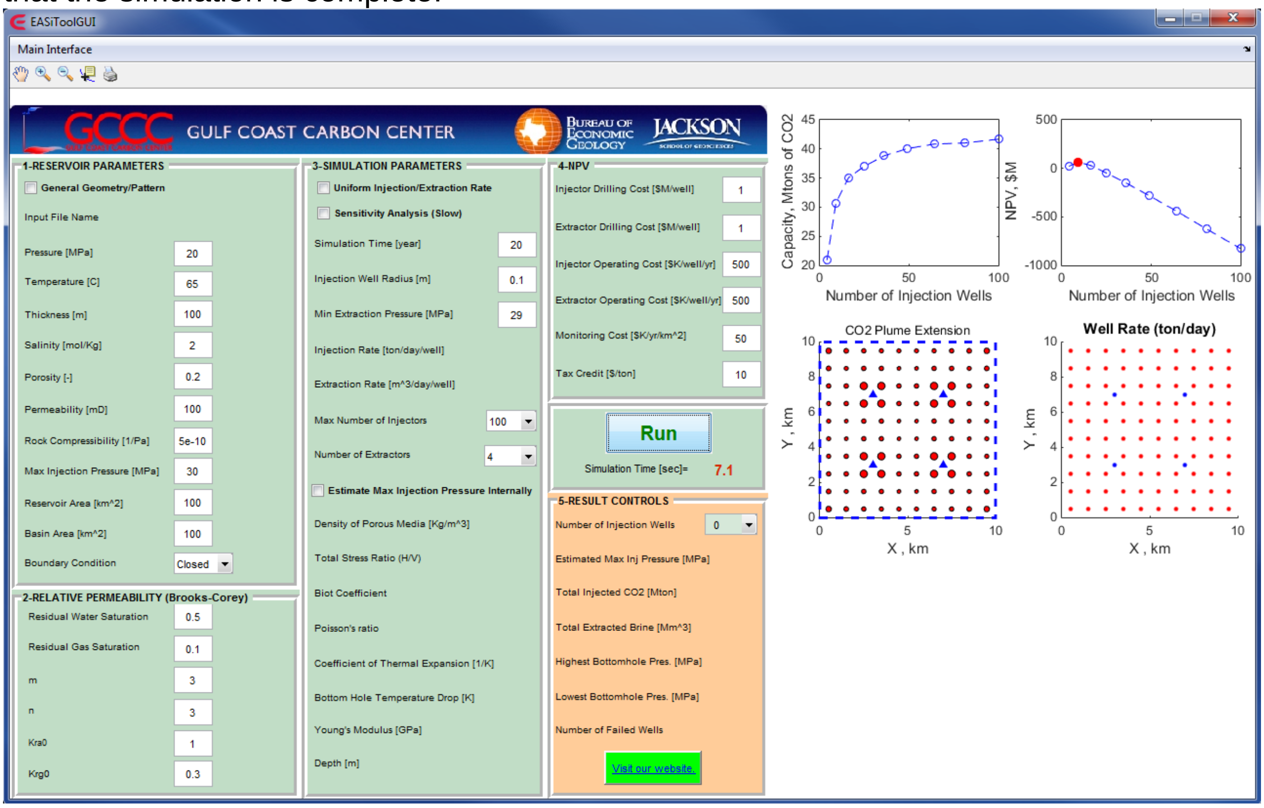
Drilling Cost	≥ 0.0001 million $/well
Operation Cost	≥ 0.0001 thousand $/well/year
Monitoring Cost	≥ 0.0001 thousand $/year/km^2
Tax Credit	≥ 0.0 $/ton
Drilling Cost of Extractors	≥ 0.0001 million $/well
Operation Cost of Extractors	≥ 0.0001 thousand $/well/year

Running the Simulation

To run the simulation, click "Run" in the EASiTool interface. A message box pops up, showing the progress in calculations:



The simulation results will appear on the right side of the controller window to inform you that the simulation is complete:



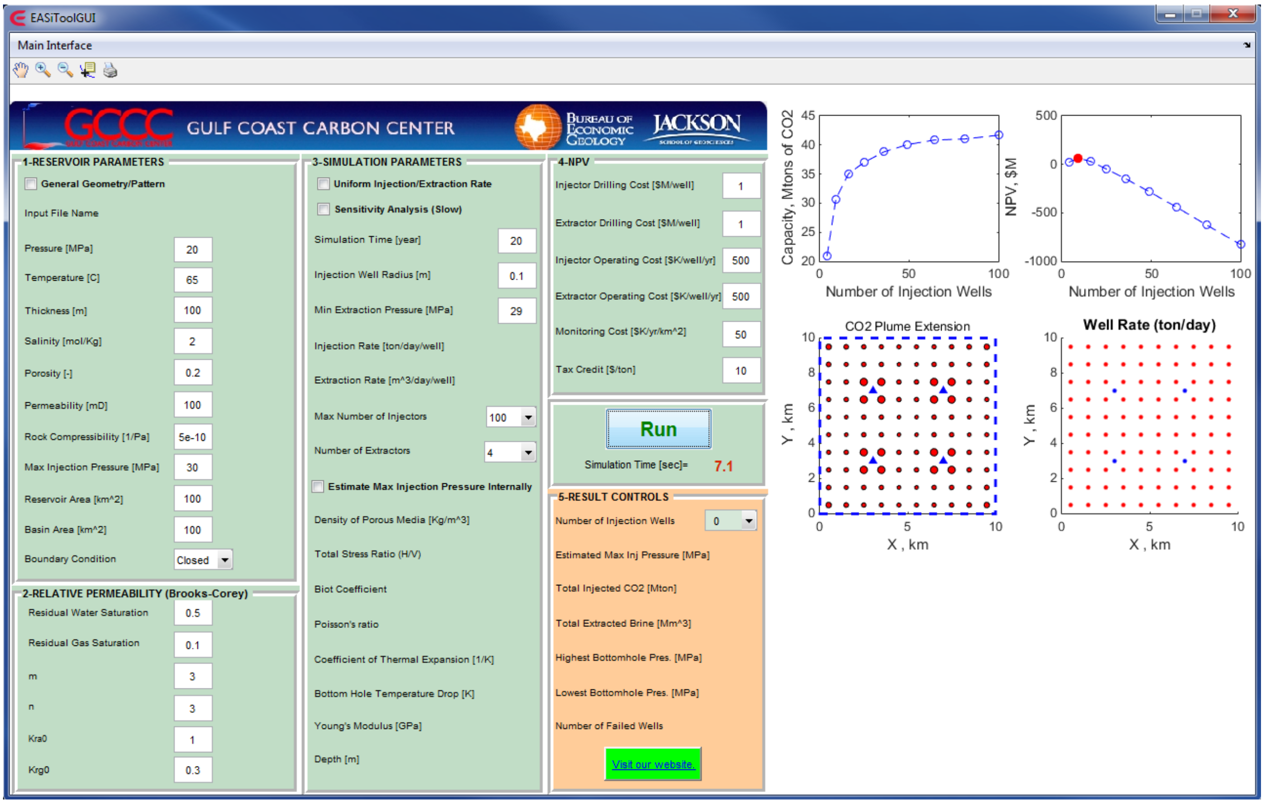
Outputs

This section provides information on how to evaluate the outputs of EASiTool.

1. Optimal Constant-Injection/Extraction Rate

Optimal constant-injection/extraction rate: This procedure guarantees that nonidentical constant-injection/extraction rates are calculated optimally at each well to meet the maximum pressure limit for the injectors and the minimum user-defined pressure limit for the extractors at the end of simulation time. For example, if the pressure limit of injectors is selected to be 30 MPa and the minimum pressure of extractors is selected to be 29 MPa for a 20-year simulation, then the program will calculate injection and extraction rates for all wells so that the bottom-hole pressure of the injectors and extractors will be 30 MPa and 29 MPa at the end of 20 years. If the calculated injection and extraction rates exceed 2,000 ton/day and 2,000 m^3/day, respectively, a warning message box will appear.

After completing a simulation using the default "optimal constant-injection/extraction rate" option, you can see the results on the right-hand side of the window:

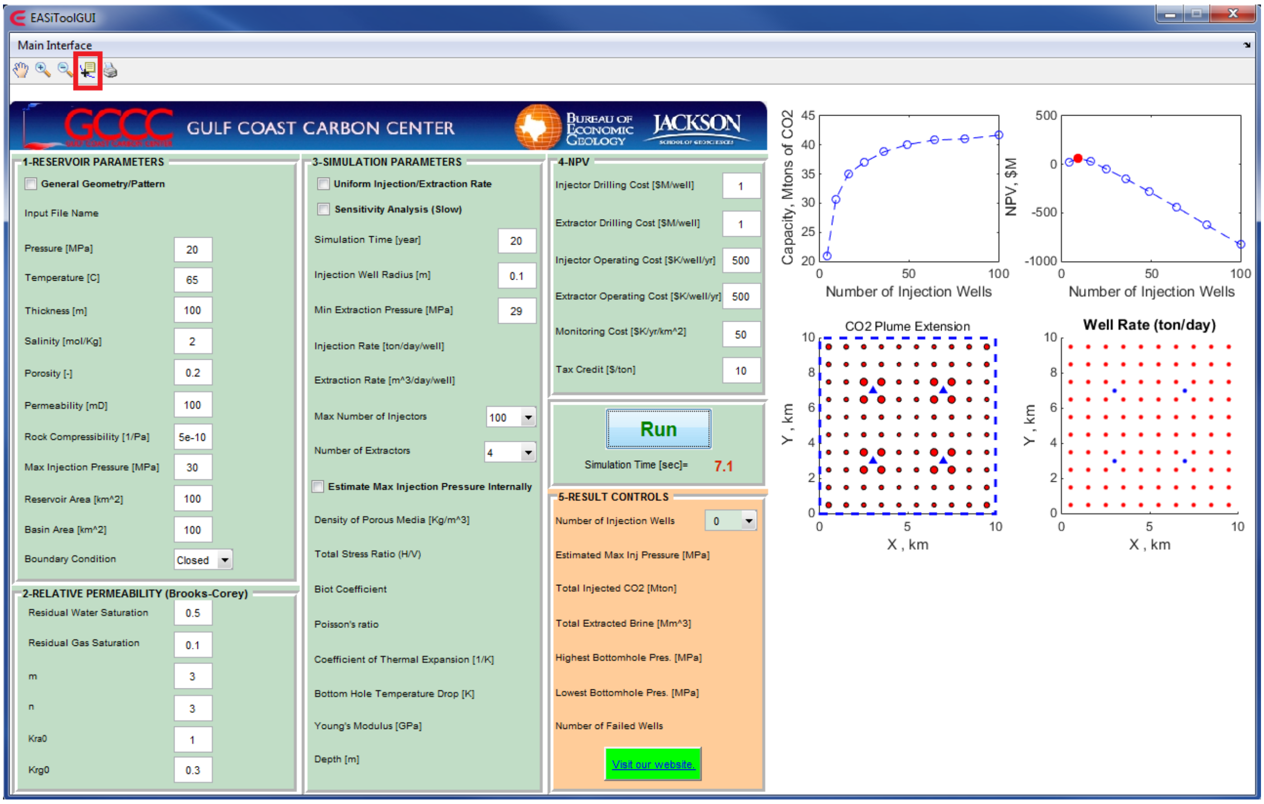


The results include the "Storage Capacity (Mtons of CO_2)," "NPV ($M)," "$CO_2$ Plume Extension" (graphical map view of the CO_2 plumes and the location of extractors), and "Well Rate (ton/day)" for injectors and extractors.

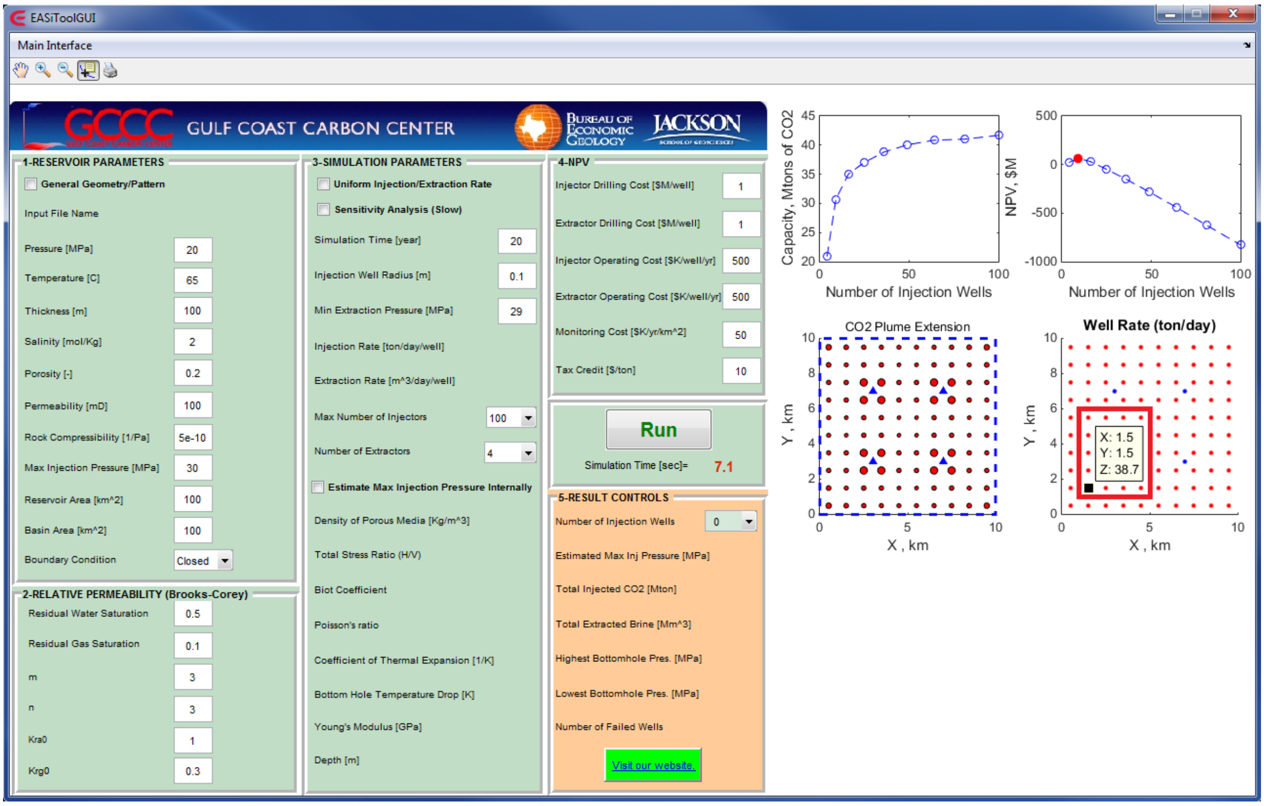
The output text file will be saved where the installation folder was installed.

> **Note**: Make sure that the installation folder is writable. Otherwise, the output file will not be saved.

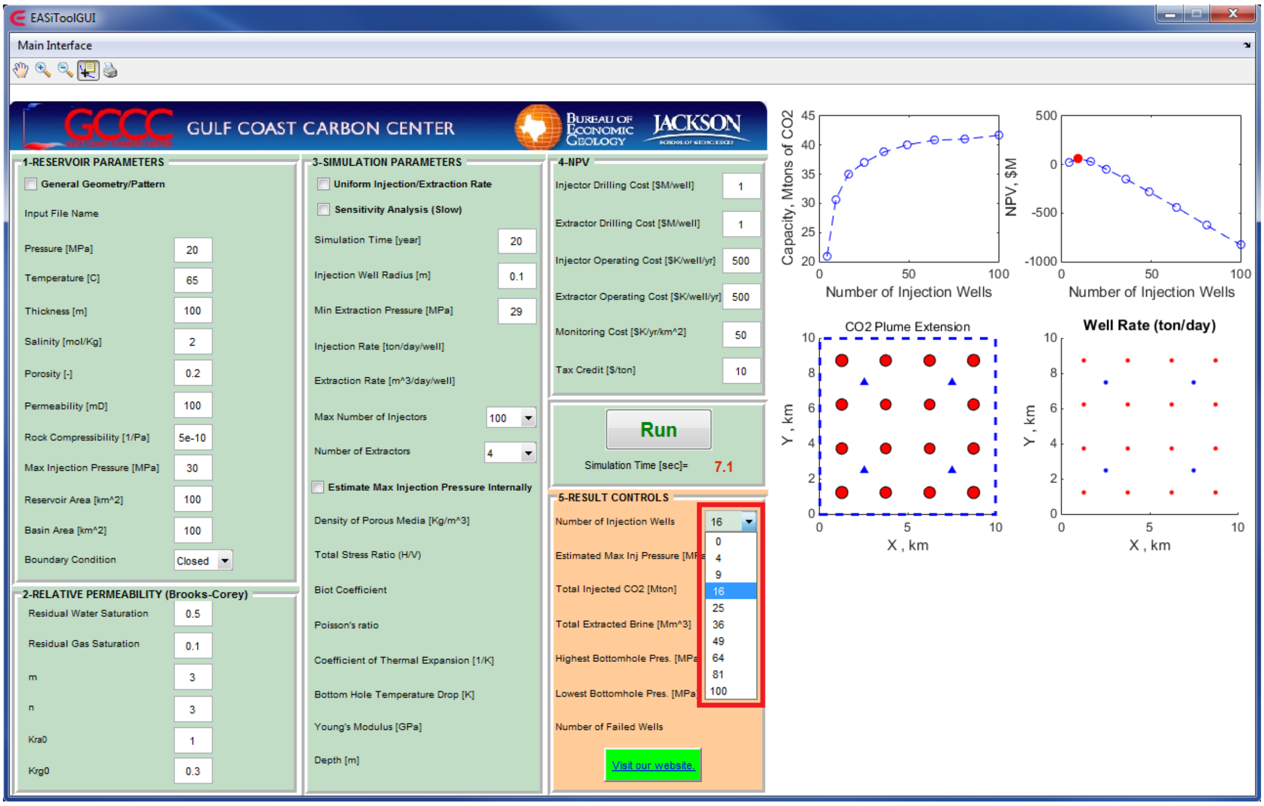
To look at the values, press the "Data Cursor" icon in the upper tab:



Then, click on the "Well Rate" plot to see the value and coordinates of each well:



The number of injection wells can be changed by clicking on the drop-down menu for "Number of Injection Wells":



The total CO_2 storage capacity and NPV of the simulated scenario based on the number of injection wells can be viewed by clicking on the circles of the "Capacity" and "NPV" plots.

The "Zoom In" and "Zoom Out" options can be used to focus on the output figures.

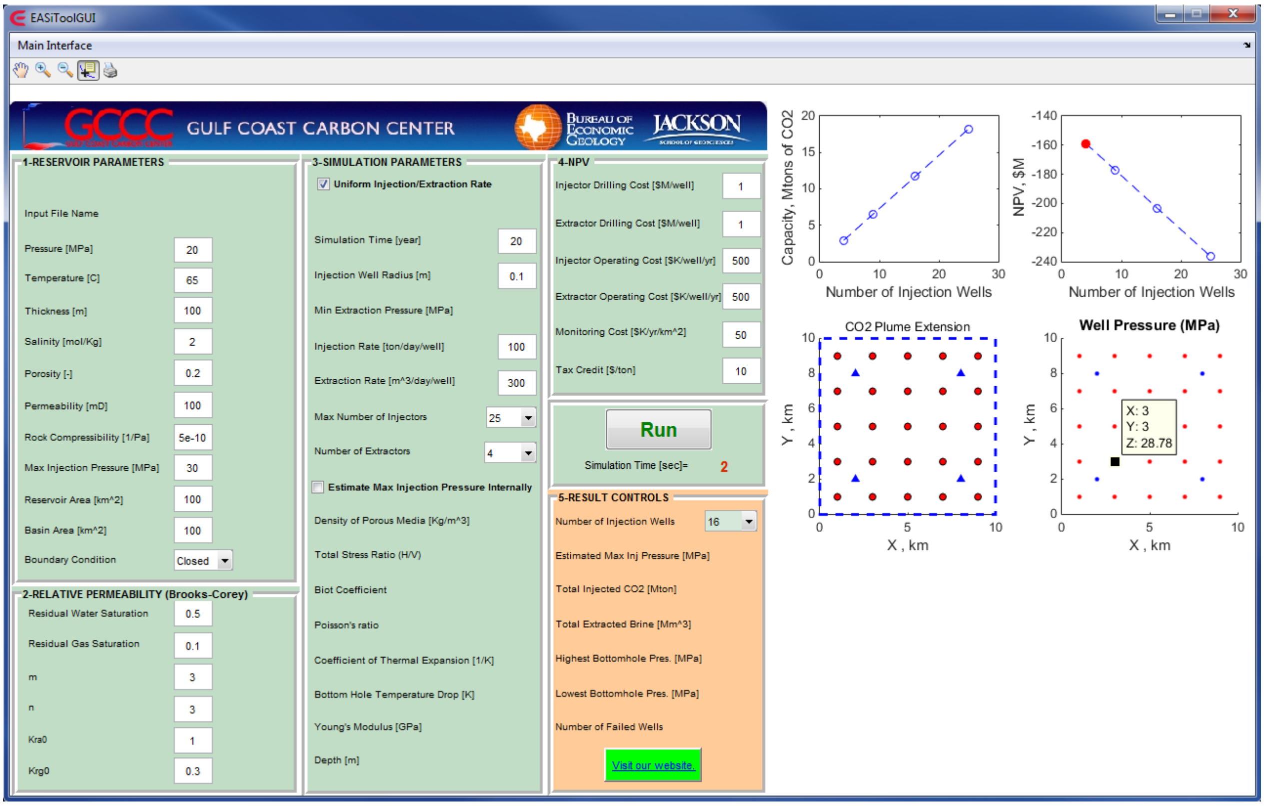
The units of CO_2 injection and brine extraction rates are ton/day in the "Well Rate" figure. The brine extraction rate unit can be converted from ton/day to sm^3/day (standard cubic meter per day) using the following table:

Salinity (mol/kg)	Brine Density (kg/m^3)
0	999.0
1	1038.4
2	1081.4
3	1127.2
4	1175.5
5	1226.6
6	1280.2

2. Uniform Constant-Injection/Extraction Rate

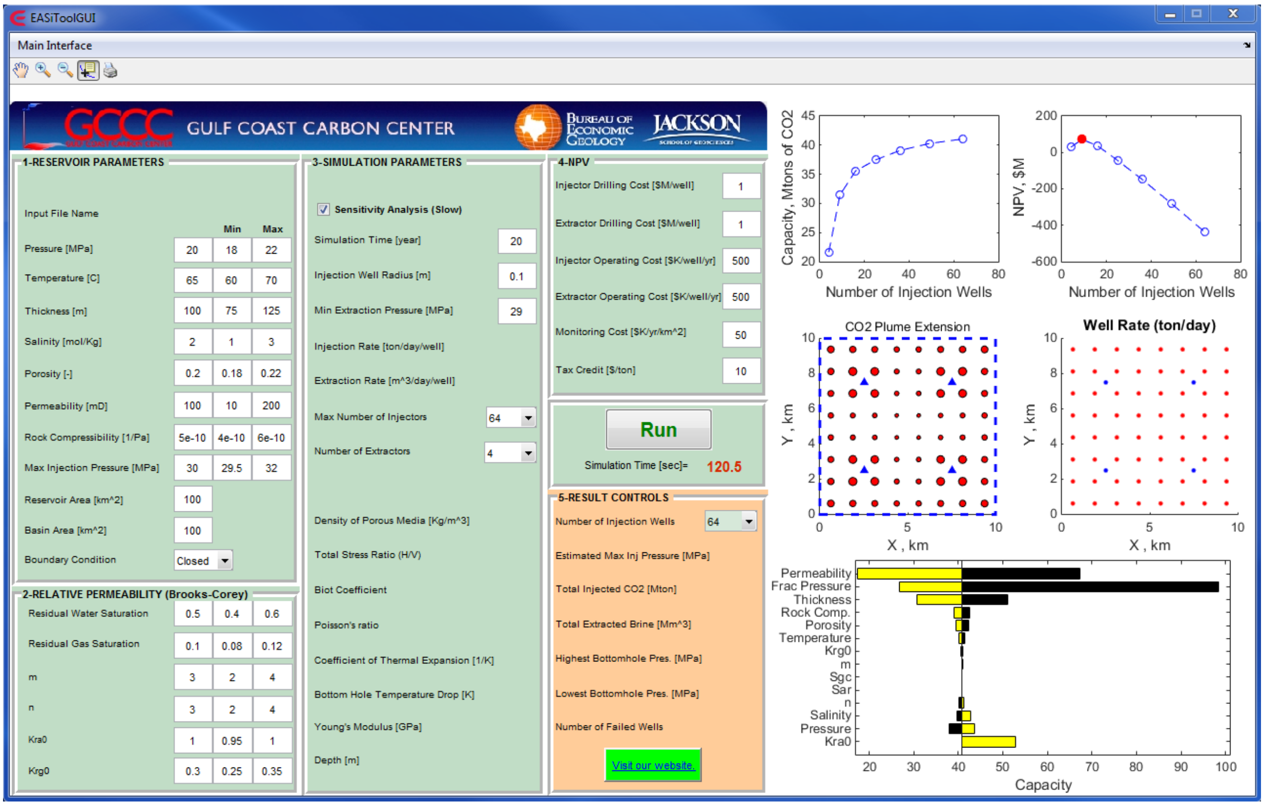
Uniform constant-injection/extraction rate: This procedure applies identical constant-injection/extraction rates at each well. The program will calculate the final pressures of all injectors and extractors. The calculated final injection pressures will be compared with the user-defined or estimated maximum injection pressure at the end of simulations. Also, the calculated final extraction pressures will be compared with 50% of the initial pressure. If the calculated pressures fall outside the acceptable range, a warning message box will appear.

After completing a simulation using the "uniform constant-injection/extraction rate" option, you can see the results on the right-hand side of the window:



3. Sensitivity Analysis

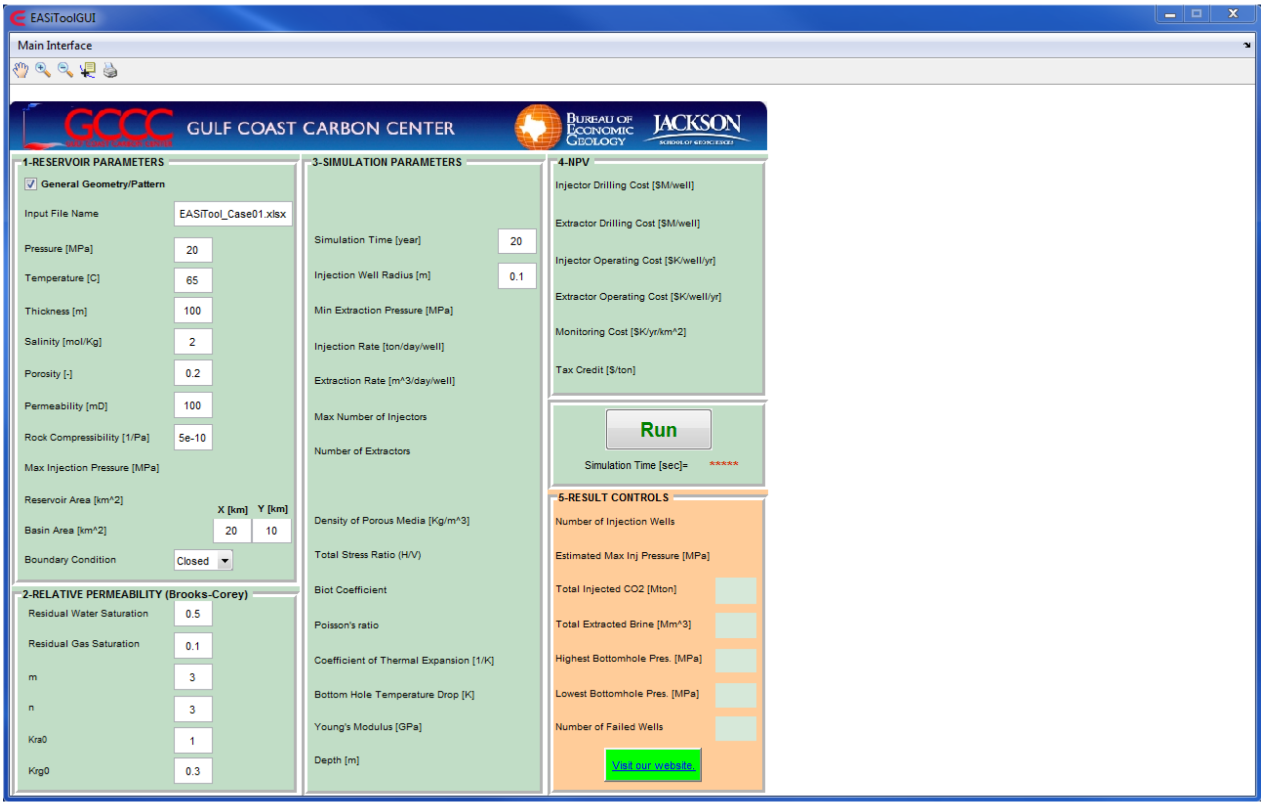
After completing a simulation with sensitivity analysis, you can see the results on the right-hand side of the window:



The tornado chart on the lower right shows the impact of each parameter on the total capacity. In this chart, the parameters are listed downward from the highest direct impact to the highest inverse impact.

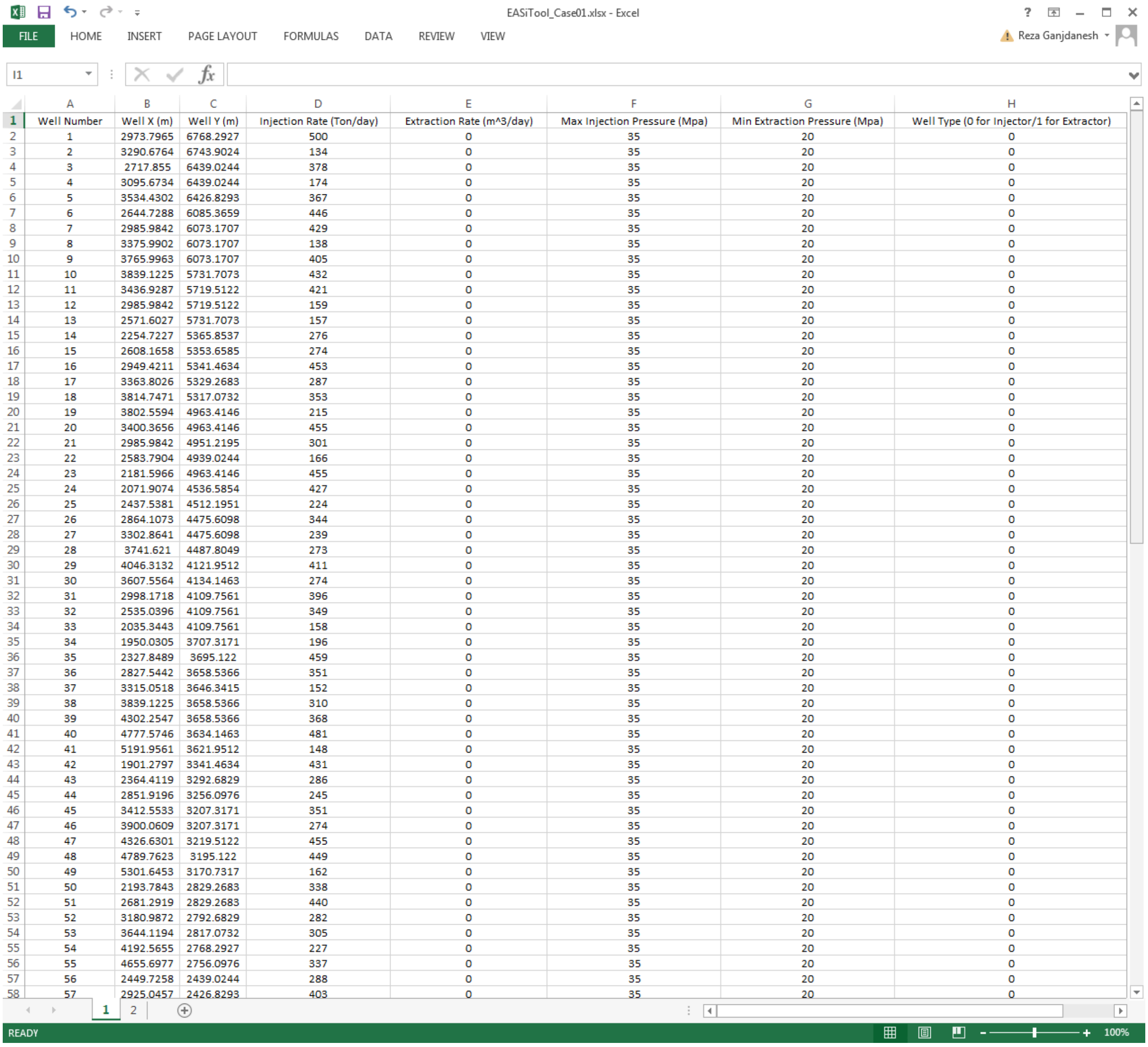
General Geometry/Pattern

This module provides users with flexibility of selecting well locations and constraints as well as reservoir and basin shape. In reality, multiple reservoirs with arbitrary shapes might be under storage operations. Also, various well constraints and patterns might be used in different reservoirs. In this module, user will be capable of including an Excel input file containing several arbitrary-shaped reservoirs with various well patterns and constraints. To activate this option, check "General Geometry/Pattern." Here, you can include the input file name and define the length and width of the basin as well as the other parameters defined in the input parameters section:



The basin can be a rectangle with a maximum length-to-width ratio of 10.

User has been provided with an example Excel input file named "EASiTool_Case01.xlsx." This Excel input file can be found where the installation folder was installed. The first sheet of the example file includes the well number, well location in X (m) and Y (m) directions, injection rate (ton/day), extraction rate (m^3/day), maximum allowable pressure (MPa), minimum allowable pressure (MPa), and well type. The origin of the coordinate system for all wells is the left lower edge of the basin. Injectors and extractors are assigned by 0 and 1 indicators, respectively. All extractors must be listed after injectors. There is no upper limit for the number of wells. The rest of reservoir, relative permeability, and simulation parameters can be entered through the interface as before. Here, you can see a screen shot of the example first sheet:



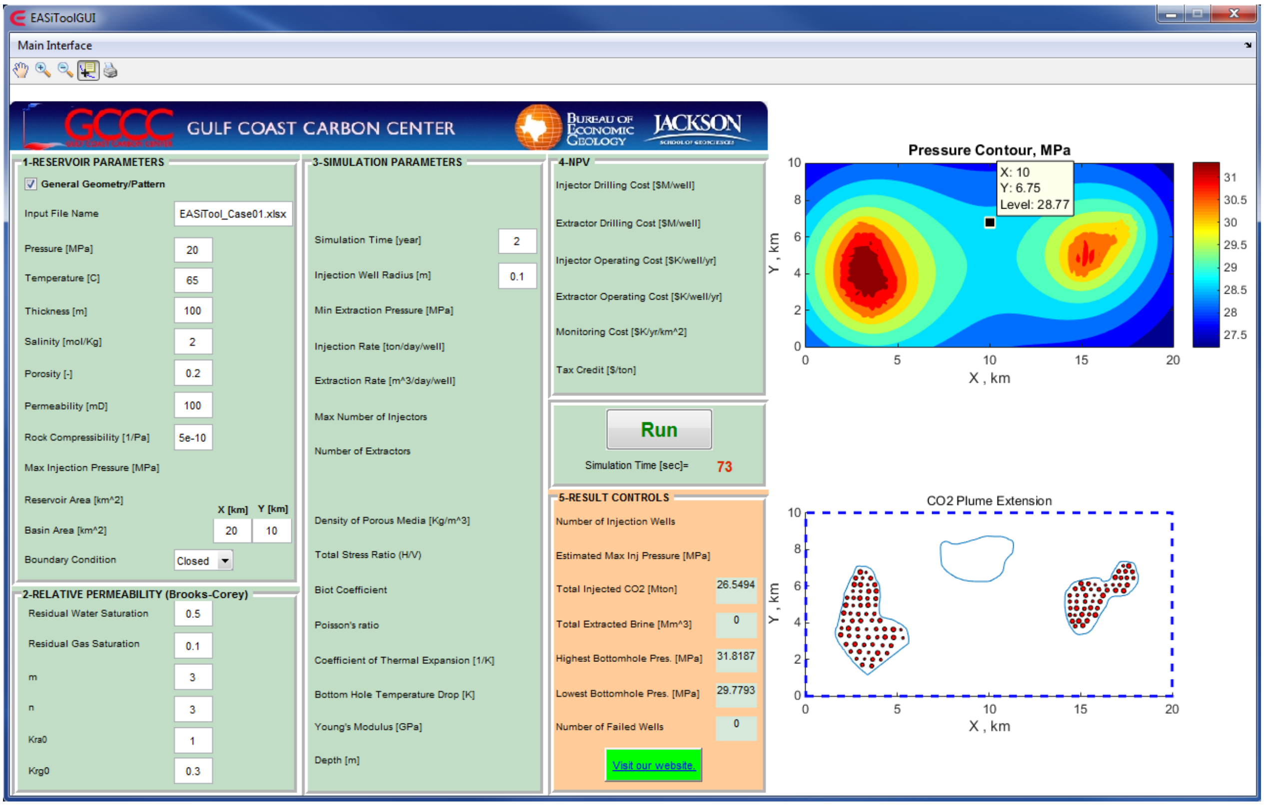
	Well Number	Well X (m)	Well Y (m)	Injection Rate (Ton/day)	Extraction Rate (m^3/day)	Max Injection Pressure (Mpa)	Min Extraction Pressure (Mpa)	Well Type (0 for Injector/1 for Extractor)
2	1	2973.7965	6768.2927	500	0	35	20	0
3	2	3290.6764	6743.9024	134	0	35	20	0
4	3	2717.855	6439.0244	378	0	35	20	0
5	4	3095.6734	6439.0244	174	0	35	20	0
6	5	3534.4302	6426.8293	367	0	35	20	0
7	6	2644.7288	6085.3659	446	0	35	20	0
8	7	2985.9842	6073.1707	429	0	35	20	0
9	8	3375.9902	6073.1707	138	0	35	20	0
10	9	3765.9963	6073.1707	405	0	35	20	0
11	10	3839.1225	5731.7073	432	0	35	20	0
12	11	3436.9287	5719.5122	421	0	35	20	0
13	12	2985.9842	5719.5122	159	0	35	20	0
14	13	2571.6027	5731.7073	157	0	35	20	0
15	14	2254.7227	5365.8537	276	0	35	20	0
16	15	2608.1658	5353.6585	274	0	35	20	0
17	16	2949.4211	5341.4634	453	0	35	20	0
18	17	3363.8026	5329.2683	287	0	35	20	0
19	18	3814.7471	5317.0732	353	0	35	20	0
20	19	3802.5594	4963.4146	215	0	35	20	0
21	20	3400.3656	4963.4146	455	0	35	20	0
22	21	2985.9842	4951.2195	301	0	35	20	0
23	22	2583.7904	4939.0244	166	0	35	20	0
24	23	2181.5966	4963.4146	455	0	35	20	0
25	24	2071.9074	4536.5854	427	0	35	20	0
26	25	2437.5381	4512.1951	224	0	35	20	0
27	26	2864.1073	4475.6098	344	0	35	20	0
28	27	3302.8641	4475.6098	239	0	35	20	0
29	28	3741.621	4487.8049	273	0	35	20	0
30	29	4046.3132	4121.9512	411	0	35	20	0
31	30	3607.5564	4134.1463	274	0	35	20	0
32	31	2998.1718	4109.7561	396	0	35	20	0
33	32	2535.0396	4109.7561	349	0	35	20	0
34	33	2035.3443	4109.7561	158	0	35	20	0
35	34	1950.0305	3707.3171	196	0	35	20	0
36	35	2327.8489	3695.122	459	0	35	20	0
37	36	2827.5442	3658.5366	351	0	35	20	0
38	37	3315.0518	3646.3415	152	0	35	20	0
39	38	3839.1225	3658.5366	310	0	35	20	0
40	39	4302.2547	3658.5366	368	0	35	20	0
41	40	4777.5746	3634.1463	481	0	35	20	0
42	41	5191.9561	3621.9512	148	0	35	20	0
43	42	1901.2797	3341.4634	431	0	35	20	0
44	43	2364.4119	3292.6829	286	0	35	20	0
45	44	2851.9196	3256.0976	245	0	35	20	0
46	45	3412.5533	3207.3171	351	0	35	20	0
47	46	3900.0609	3207.3171	274	0	35	20	0
48	47	4326.6301	3219.5122	455	0	35	20	0
49	48	4789.7623	3195.122	449	0	35	20	0
50	49	5301.6453	3170.7317	162	0	35	20	0
51	50	2193.7843	2829.2683	338	0	35	20	0
52	51	2681.2919	2829.2683	440	0	35	20	0
53	52	3180.9872	2792.6829	282	0	35	20	0
54	53	3644.1194	2817.0732	305	0	35	20	0
55	54	4192.5655	2768.2927	227	0	35	20	0
56	55	4655.6977	2756.0976	337	0	35	20	0
57	56	2449.7258	2439.0244	288	0	35	20	0
58	57	2925.0457	2426.8293	403	0	35	20	0

The reservoir boundaries can be sketched point by point using the second sheet of Excel file:

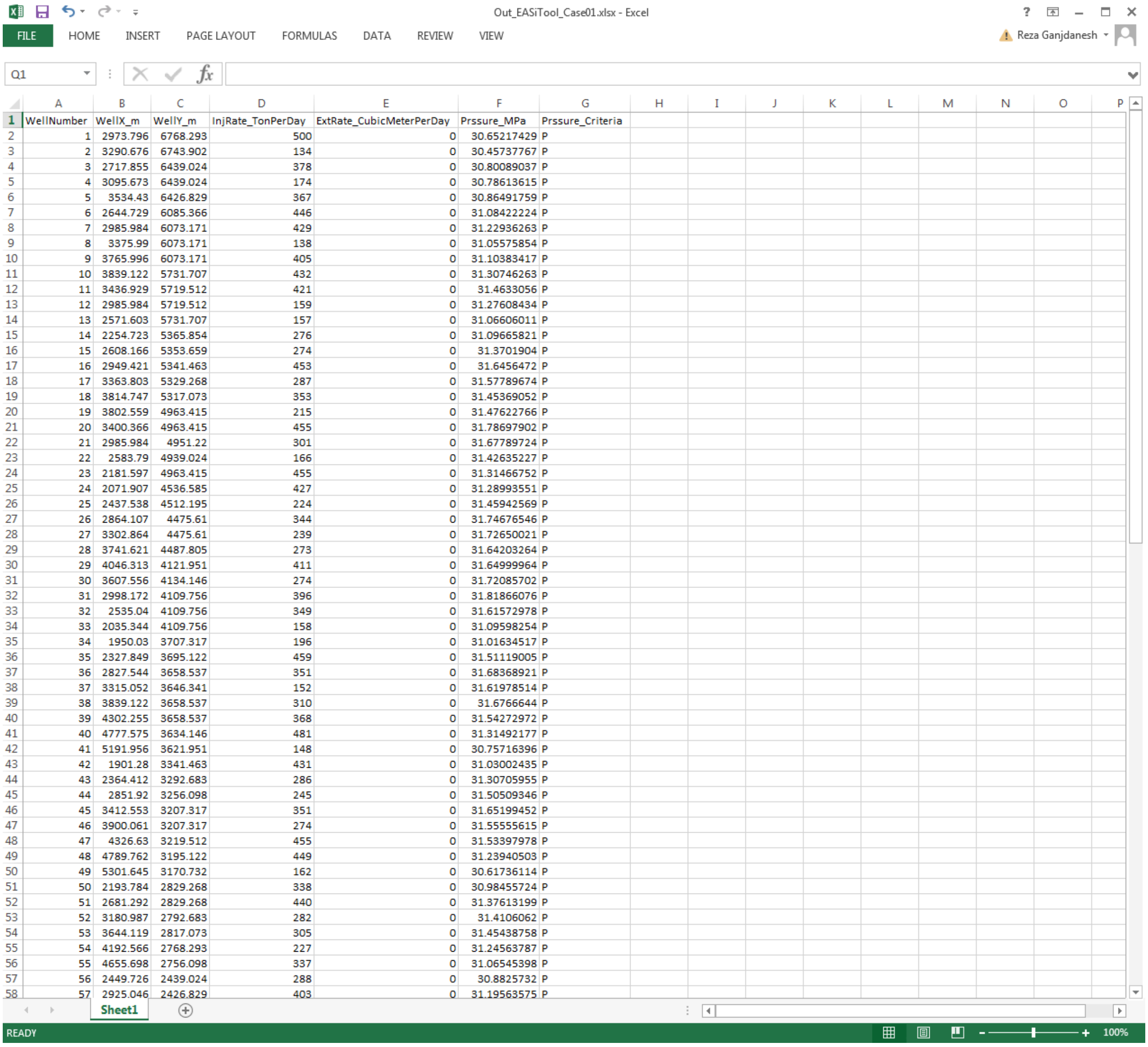
EASiTool_Case01.xlsx - Excel

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	ResX1 (m)	ResY1 (m)	ResX2 (m)	ResY2 (m)	ResX3 (m)	ResY3 (m)	ResX4 (m)	ResY4 (m)	ResX5 (m)	ResY5 (m)	ResX6 (m)	ResY6 (m)	ResX7 (m)	ResY7 (m)	ResX8 (m)	ResY8 (m)	ResX9 (m)	ResY9 (m)	ResX10 (m)	ResY10 (m)
2	3375.99	1158.537	15027.42	3365.854	10067.03	6280.488														
3	5606.338	2878.049	15161.49	3390.244	10152.35	6317.073														
4	5618.525	3073.171	15283.36	3414.634	10237.66	6365.854														
5	5606.338	3243.902	15405.24	3463.415	10347.35	6426.829														
6	5569.775	3426.829	15502.74	3536.585	10444.85	6487.805														
7	5533.211	3573.171	15588.06	3609.756	10530.16	6548.78														
8	5472.273	3695.122	15661.18	3695.122	10603.29	6597.561														
9	5374.771	3780.488	15709.93	3792.683	10700.79	6719.512														
10	5277.27	3865.854	15770.87	3878.049	10761.73	6817.073														
11	5179.768	3939.024	15844	3987.805	10798.29	6963.415														
12	5082.267	3975.61	15917.12	4109.756	10822.67	7085.366														
13	4984.765	4024.39	15978.06	4256.098	10834.86	7195.122														
14	4899.452	4085.366	16051.19	4378.049	10871.42	7317.073														
15	4814.138	4134.146	16124.31	4512.195	10907.98	7390.244														
16	4716.636	4170.732	16221.82	4646.341	10968.92	7475.61														
17	4606.947	4207.317	16307.13	4780.488	11017.67	7548.78														
18	4509.445	4219.512	16392.44	4890.244	11090.8	7609.756														
19	4411.944	4243.902	16441.19	5024.39	11151.74	7682.927														
20	4326.63	4268.293	16477.76	5134.146	11224.86	7731.707														
21	4216.941	4292.683	16514.32	5231.707	11285.8	7829.268														
22	4119.439	4341.463	16575.26	5317.073	11310.18	7963.415														
23	4058.501	4414.634	16648.39	5365.854	11322.36	8073.171														
24	4021.938	4536.585	16733.7	5426.829	11334.55	8170.732														
25	4009.75	4646.341	16806.83	5439.024	11334.55	8304.878														
26	4009.75	4768.293	16892.14	5451.22	11310.18	8414.634														
27	4009.75	4878.049	17014.02	5451.22	11224.86	8500														
28	4009.75	5036.585	17160.27	5451.22	11102.99	8536.585														
29	4034.126	5170.732	17245.58	5463.415	10993.3	8597.561														
30	4046.313	5280.488	17379.65	5487.805	10907.98	8646.341														
31	4058.501	5402.439	17501.52	5512.195	10798.29	8670.732														
32	4058.501	5524.39	17623.4	5585.366	10688.6	8707.317														
33	4046.313	5695.122	17708.71	5682.927	10566.73	8707.317														
34	4034.126	5890.244	17830.59	5768.293	10420.48	8707.317														
35	4009.75	6036.585	17903.72	5878.049	10249.85	8707.317														
36	3973.187	6146.341	17976.84	5951.22	10115.78	8719.512														
37	3924.436	6231.707	18037.78	6060.976	10006.09	8719.512														
38	3839.122	6329.268	18098.72	6146.341	9884.217	8731.707														
39	3802.559	6439.024	18135.28	6280.488	9774.528	8707.317														
40	3765.996	6573.171	18147.47	6402.439	9652.651	8682.927														
41	3729.433	6682.927	18147.47	6524.39	9530.774	8646.341														
42	3668.495	6792.683	18135.28	6646.341	9408.897	8597.561														
43	3607.556	6865.854	18086.53	6731.707	9311.395	8560.976														
44	3522.243	6951.22	18062.16	6817.073	9177.331	8524.39														
45	3424.741	7000	18025.59	6963.415	9043.266	8500														
46	3339.427	7060.976	18001.22	7060.976	8921.389	8451.22														
47	3217.55	7073.171	17964.66	7158.537	8762.949	8402.439														
48	3132.236	7073.171	17891.53	7256.098	8616.697	8365.854														
49	3046.923	7073.171	17794.03	7280.488	8433.882	8329.268														

After completing the simulation for the example, you can see the results on the right-hand side of the window. The upper figure show the pressure contours at the end of two years. The red circles and blue triangles on the lower figures show the CO_2 plume extensions and the location of extractors, respectively. A third potential storage reservoir is located in the same basin. A monitoring point at coordinates of (10km, 6.75km) is used to track the pressure buildup in the third reservoir. The result section shows the total injected CO_2, total extracted brine, highest bottomhole pressure, lowest bottomhole pressure, and the number of wells whose bottomhole pressure fail to fall within the minimum and maximum allowable pressure.



User will be provided with an Excel output file including the final bottomhole pressure of each well. The final pressure of each well will be checked with the maximum and minimum allowable pressure of each well. The results of the pressure check will be shown by 'P' or 'F' for pass or fail in the pressure criteria column of the output file.



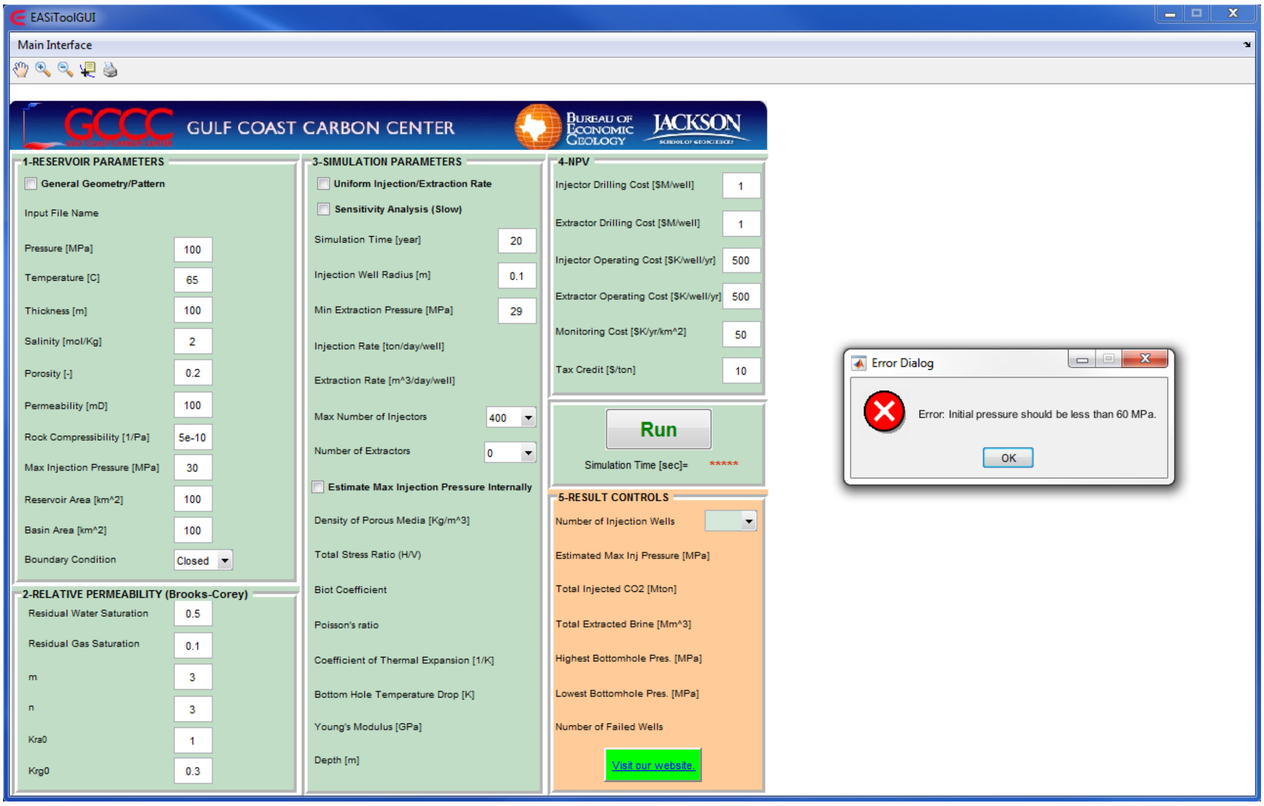
WellNumber	WellX_m	WellY_m	InjRate_TonPerDay	ExtRate_CubicMeterPerDay	Prssure_MPa	Prssure_Criteria
1	2973.796	6768.293	500	0	30.65217429	P
2	3290.676	6743.902	134	0	30.45737767	P
3	2717.855	6439.024	378	0	30.80089037	P
4	3095.673	6439.024	174	0	30.78613615	P
5	3534.43	6426.829	367	0	30.86491759	P
6	2644.729	6085.366	446	0	31.08422224	P
7	2985.984	6073.171	429	0	31.22936263	P
8	3375.99	6073.171	138	0	31.05575854	P
9	3765.996	6073.171	405	0	31.10383417	P
10	3839.122	5731.707	432	0	31.30746263	P
11	3436.929	5719.512	421	0	31.4633056	P
12	2985.984	5719.512	159	0	31.27608434	P
13	2571.603	5731.707	157	0	31.06606011	P
14	2254.723	5365.854	276	0	31.09665821	P
15	2608.166	5353.659	274	0	31.3701904	P
16	2949.421	5341.463	453	0	31.6456472	P
17	3363.803	5329.268	287	0	31.57789674	P
18	3814.747	5317.073	353	0	31.45369052	P
19	3802.559	4963.415	215	0	31.47622766	P
20	3400.366	4963.415	455	0	31.78697902	P
21	2985.984	4951.22	301	0	31.67789724	P
22	2583.79	4939.024	166	0	31.42635227	P
23	2181.597	4963.415	455	0	31.31466752	P
24	2071.907	4536.585	427	0	31.28993551	P
25	2437.538	4512.195	224	0	31.45942569	P
26	2864.107	4475.61	344	0	31.74676546	P
27	3302.864	4475.61	239	0	31.72650021	P
28	3741.621	4487.805	273	0	31.64203264	P
29	4046.313	4121.951	411	0	31.64999964	P
30	3607.556	4134.146	274	0	31.72085702	P
31	2998.172	4109.756	396	0	31.81866076	P
32	2535.04	4109.756	349	0	31.61572978	P
33	2035.344	4109.756	158	0	31.09598254	P
34	1950.03	3707.317	196	0	31.01634517	P
35	2327.849	3695.122	459	0	31.51119005	P
36	2827.544	3658.537	351	0	31.68368921	P
37	3315.052	3646.341	152	0	31.61978514	P
38	3839.122	3658.537	310	0	31.6766644	P
39	4302.255	3658.537	368	0	31.54272972	P
40	4777.575	3634.146	481	0	31.31492177	P
41	5191.956	3621.951	148	0	30.75716396	P
42	1901.28	3341.463	431	0	31.03002435	P
43	2364.412	3292.683	286	0	31.30705955	P
44	2851.92	3256.098	245	0	31.50509346	P
45	3412.553	3207.317	351	0	31.65199452	P
46	3900.061	3207.317	274	0	31.55555615	P
47	4326.63	3219.512	455	0	31.53397978	P
48	4789.762	3195.122	449	0	31.23940503	P
49	5301.645	3170.732	162	0	30.61736114	P
50	2193.784	2829.268	338	0	30.98455724	P
51	2681.292	2829.268	440	0	31.37613199	P
52	3180.987	2792.683	282	0	31.4106062	P
53	3644.119	2817.073	305	0	31.45438758	P
54	4192.566	2768.293	227	0	31.24563787	P
55	4655.698	2756.098	337	0	31.06545398	P
56	2449.726	2439.024	288	0	30.8825732	P
57	2925.046	2426.829	403	0	31.19563575	P

Warning and Error Dialogs

Several warning and error dialogs have been designed to help users with the simulation process. The warning and error dialogs may pop up before, during and after simulations.

Presimulation Errors

The range of acceptable input parameters were listed in the "Input Parameters" section. If one or more entered parameter is out of the acceptable range, an error will pop up at the beginning of the simulation and the simulation will not proceed. For example, if the entered initial pressure is 100 MPa, the following error will pop up:

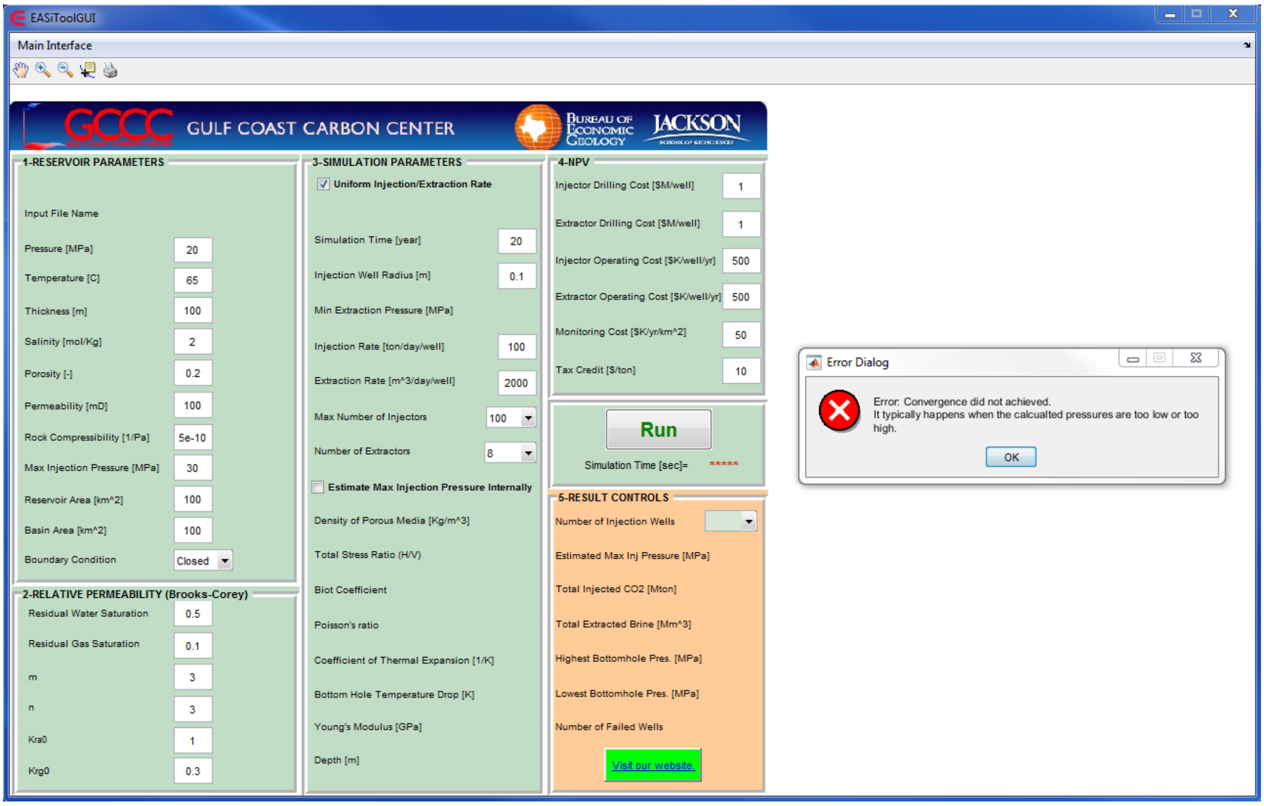


Midsimulation Errors

When the simulation cannot reach the convergence the simulation will fail. The main reasons for convergence failure are the following:

- The total rate of extraction is much higher than total rate of injection, which results in over-depletion of reservoir.
- The total rate of injection is much higher than total rate of extraction, which results in over-pressurization of reservoir.

In the following example, the total extraction rate using eight extractors is much higher than the total injection rate using nine injectors. Therefore, the reservoir pressure becomes unrealistic and the convergence fails.

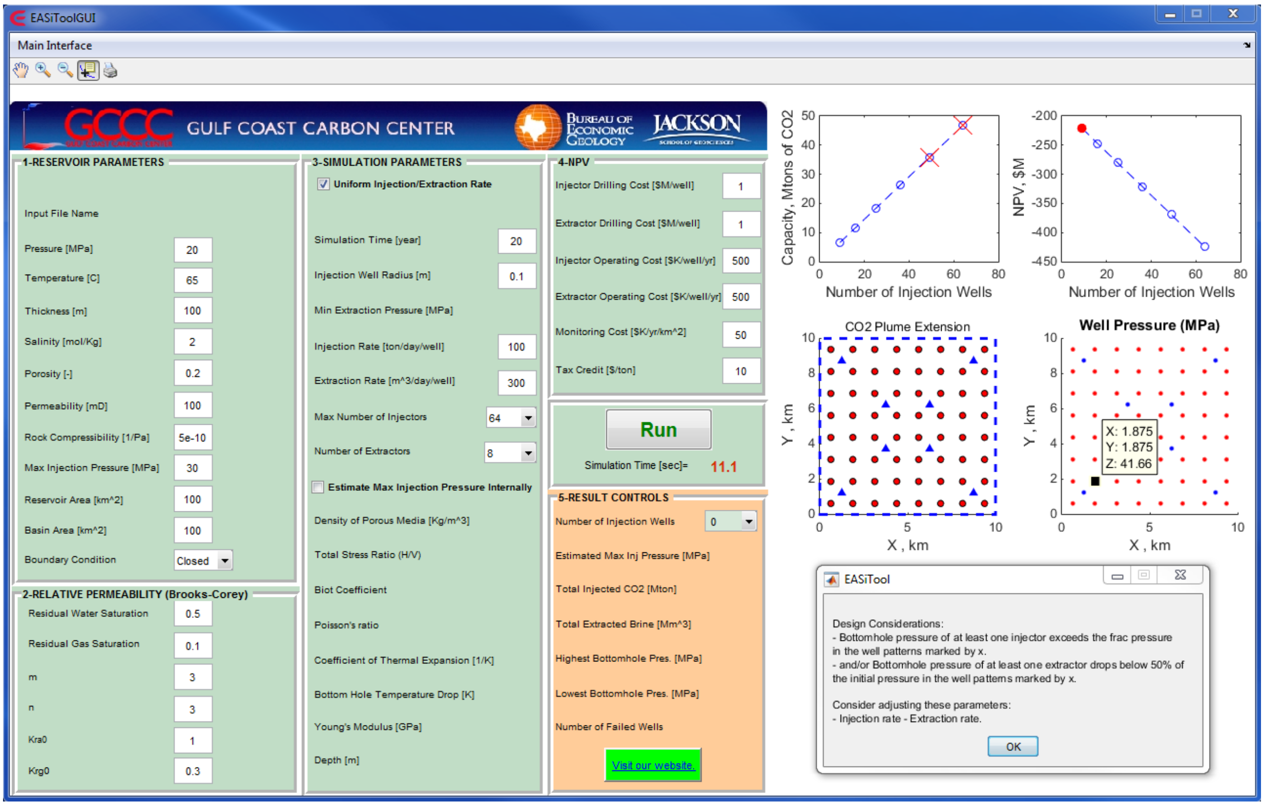


Postsimulation Warnings

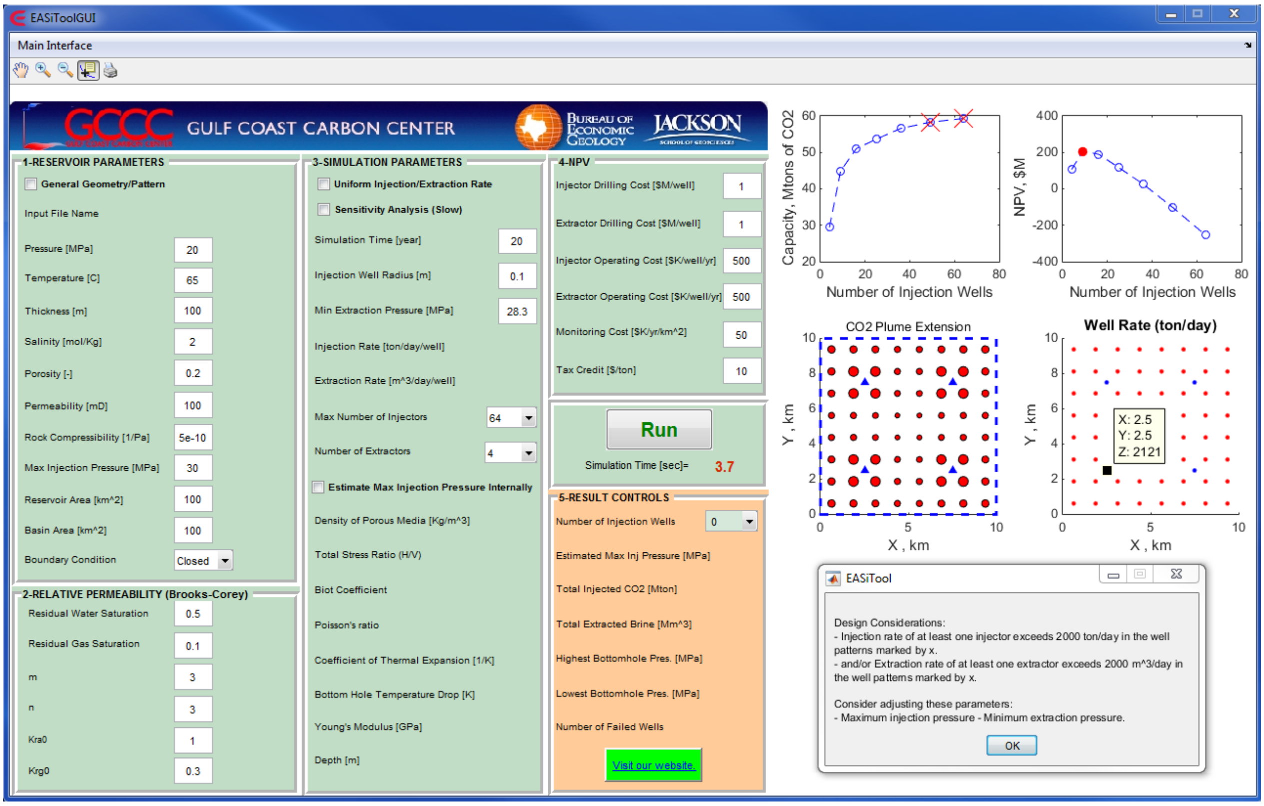
When the simulation is finished, the results will be compared with the monitoring constraints. The monitoring constraints are the following:

- Uniform Injection/Extraction Rate: "Max Injection Pressure" for injectors and 50% of the initial pressure for the extractors.
- Optimal Injection/Extraction Rate: 2,000 ton/day for injectors and 2,000 m^3/day for extractors.

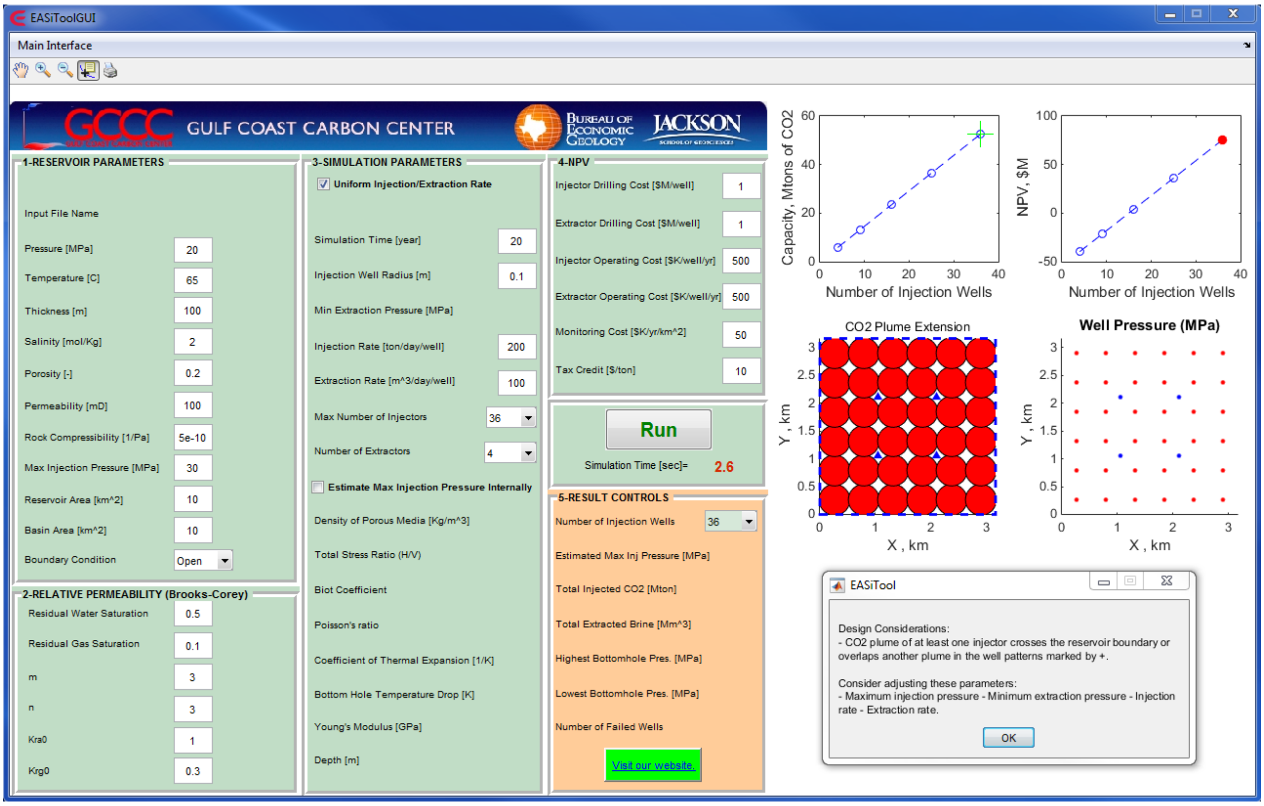
In the "Uniform Injection/Extraction Rate" case, if the calculated pressures violate the monitoring constraints, a warning will pop up at the end of the simulation and the following will be suggested: adjust the operating constraints ("Injection Rate" and/or "Extraction Rate"). In the following example, the bottom-hole pressure of some injectors in well patterns of 49 and 64 injectors increases above the "Max Injection Pressure." The well patterns which have out of the range pressures will be marked by a red "X."



In the "Optimal Injection/Extraction Rate" case, if the calculated rates violate the monitoring constraints, a warning will pop up at the end of the simulation, and the following will be suggested: adjust the operating constraints ("Max Injection Pressure" and/or "Minimum Extraction Pressure"). In the following example, the extraction rate of some extractors in well patterns of 49 and 64 injectors is above 2,000 m^3/day. The well patterns which have out of the range rates will be marked by a red "X."



At the end of the simulations, the plume extensions will be checked to make sure the CO_2 plumes do not overlap or cross the reservoir boundaries. If the CO_2 plumes overlap or cross the reservoir boundaries, a warning message will pop up and the well patterns with oversized plumes will be marked by a green "+". In the following example, some of the CO_2 plumes overlap or cross the boundaries for well pattern of 36 injectors.



Examples and Verifications

Table 1 summarizes the input for the EASiTool template. The aquifer is located at a depth of 1,000 m. In this study, the problem was solved for closed and open boundary conditions. The basin area is the same as the reservoir area for the case of the closed boundary condition. The basin area is 10,000 km^2 for the case of the open boundary condition. The maximum allowable injection pressure is assumed to be 20 MPa.

Table 1: Reservoir Parameters

Initial pressure, MPa	10
Initial temperature, ˚C	40
Thickness, m	100
Salinity, kg/mol	0
Porosity	0.2
Permeability, mD	100
Rock compressibility, 1/Pa	5.0E-10
Maximum injection pressure, MPa	20
Reservoir area, km^2	100
Basin area, km^2	100 or 10,000
Boundary Condition	Closed or Open

Table 2 summarizes the relative permeability parameters used in the Brooks-Corey model for a two-phase flow of gas and aqueous phases.

Table 2: Relative Permeability Parameters for Brooks-Corey Model

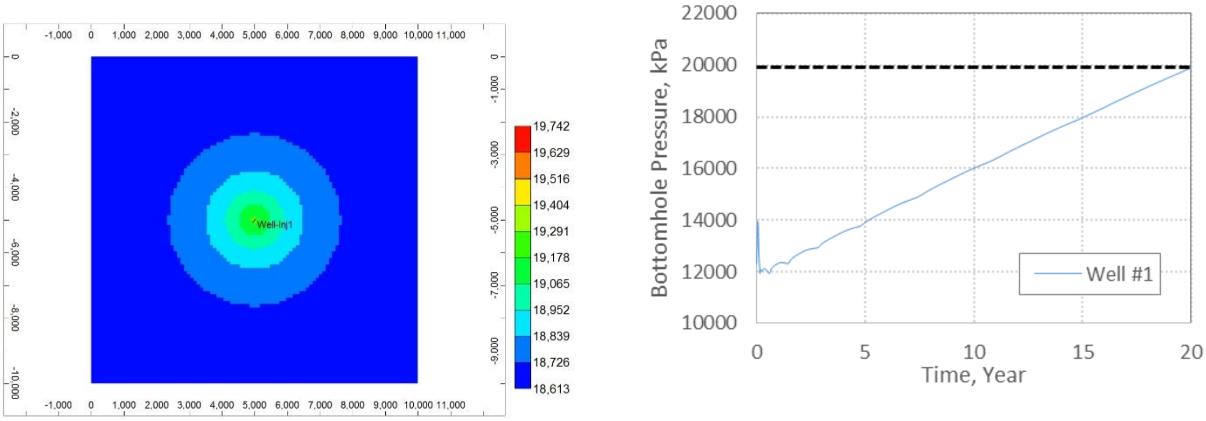
Residual water saturation, S_{wr}	0.5
Residual gas saturation, S_{gr}	0.1
Water exponent, m	3.0
Gas exponent, n	3.0
Water end-point relative permeability, k_{rw}°	1.0
Gas end-point relative permeability, k_{rg}°	0.3

Table 3 shows the simulation parameters.

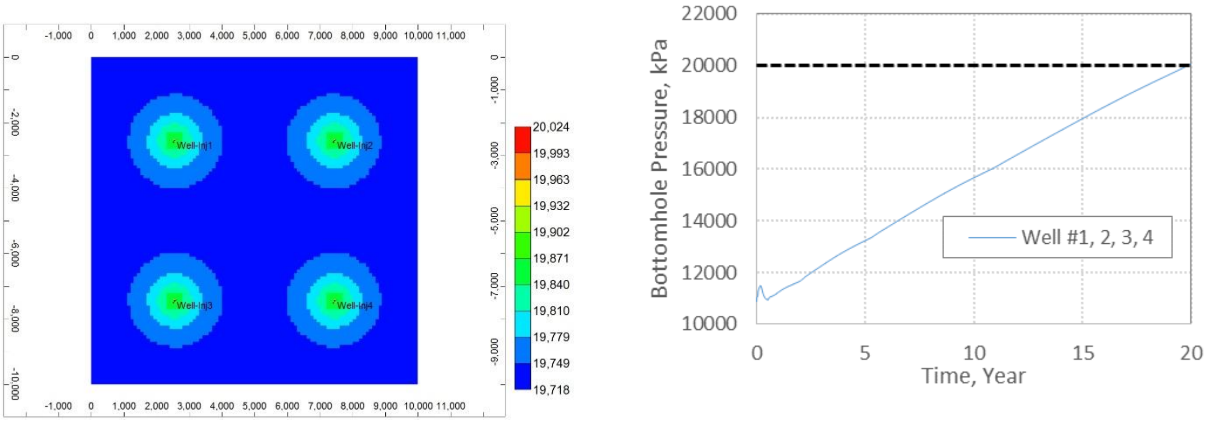
Table 3: Simulation Parameters

Simulation time, year	20
Injection well radius, m	0.1
Minimum extraction pressure, MPa	19
Maximum number of injectors	16
Number of extractors	0

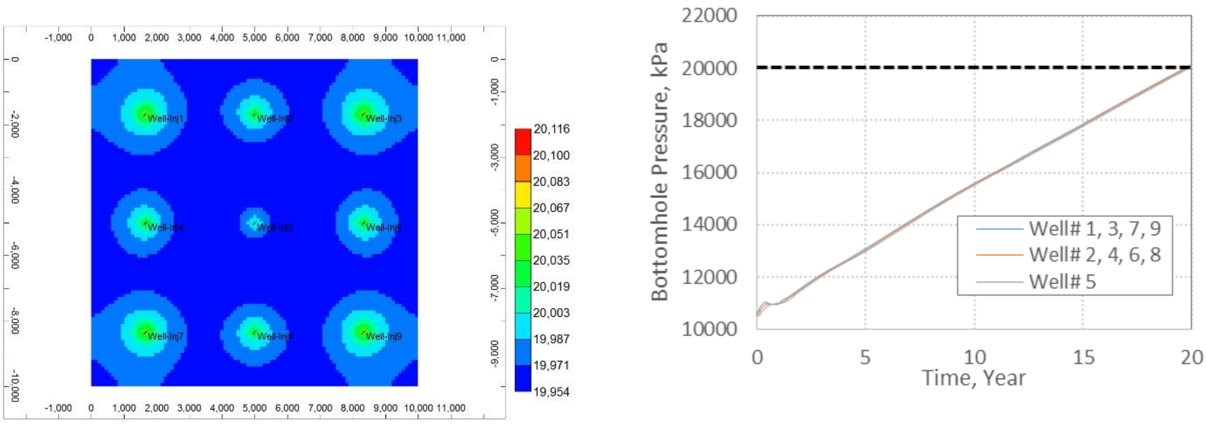
The basin models were prepared for numerical simulation using GEM by CMG (Computer Modeling Group) for both boundary conditions. The injection rates calculated by EASiTool were used in numerical simulation to compare the analytical and numerical results. Figure 1 shows the pressure distributions throughout the reservoir and bottom-hole pressures of all wells after 20 years of injection using 1, 4, 9, and 16 injectors. The injection rates were calculated using the closed boundary condition of EASiTool. The color legend shows the range of pressure throughout the reservoir at the end of 20 years. It is observed that the maximum pressure in the reservoir is very close to the target pressure of 20 MPa. The pressure distribution is more uniform by using more injectors. The bottom-hole pressure of all wells is very similar throughout the injection period.



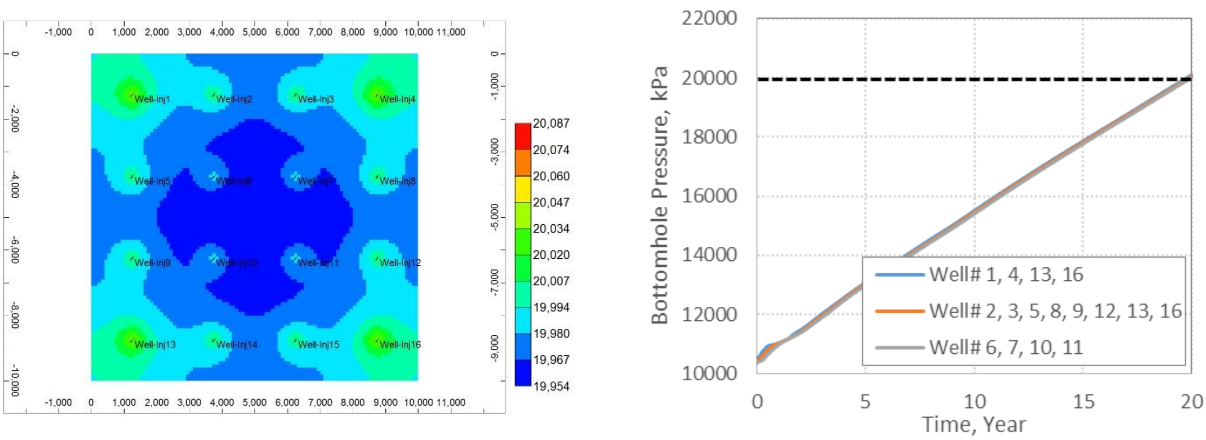
a) 1 well



b) 4 wells



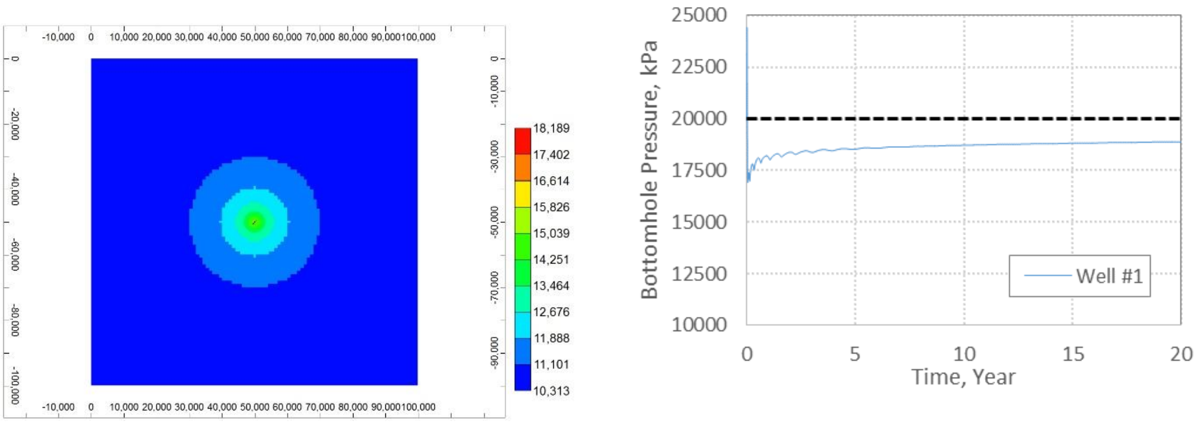
c) 9 wells



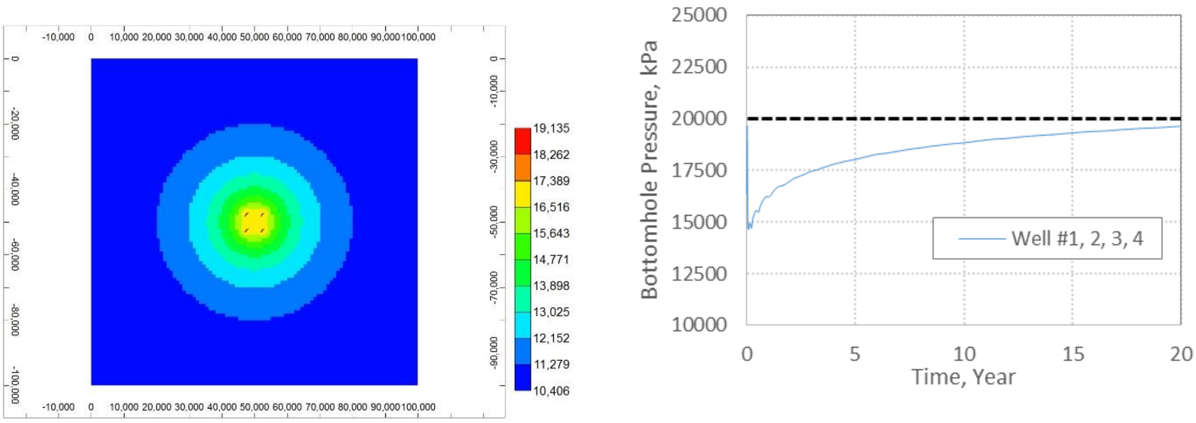
d) 16 wells

Figure 1: Pressure distributions and bottom-hole pressures for the closed boundary condition after 20 years of constant injection at a depth of 1000 m.

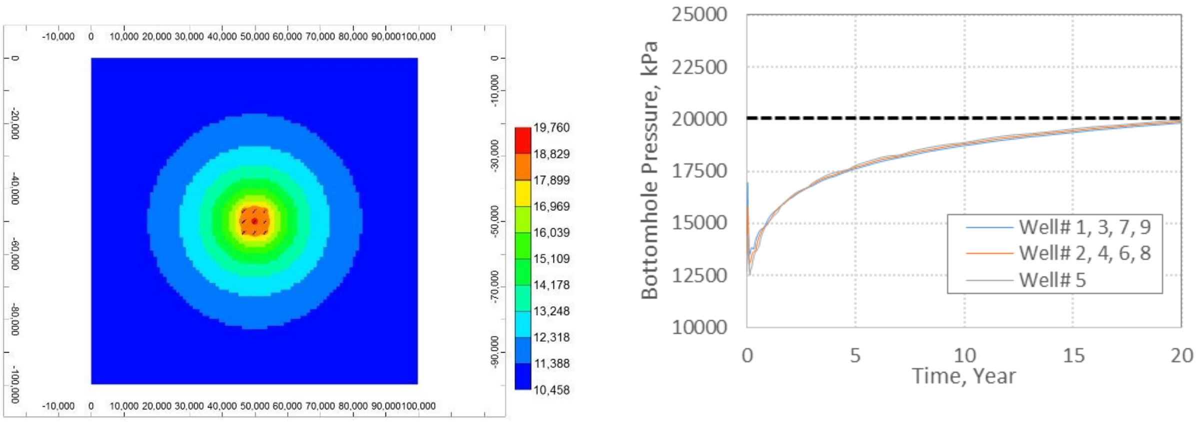
Figure 2 shows the pressure distributions and bottom-hole pressures after 20 years of injection using the open boundary condition. A 100-km² reservoir is located at the center of a 10,000-km² basin. The final pressure from simulations differs slightly from the final pressure of 20 MPa used for calculating the rates by EASiTool. This difference decreases when more injectors are used. In addition, the simulation results show that the effect of pressure reaches the boundaries of the basin at the end of the injection process. The implication is that the open boundary condition is not accurate for a 20-year process.



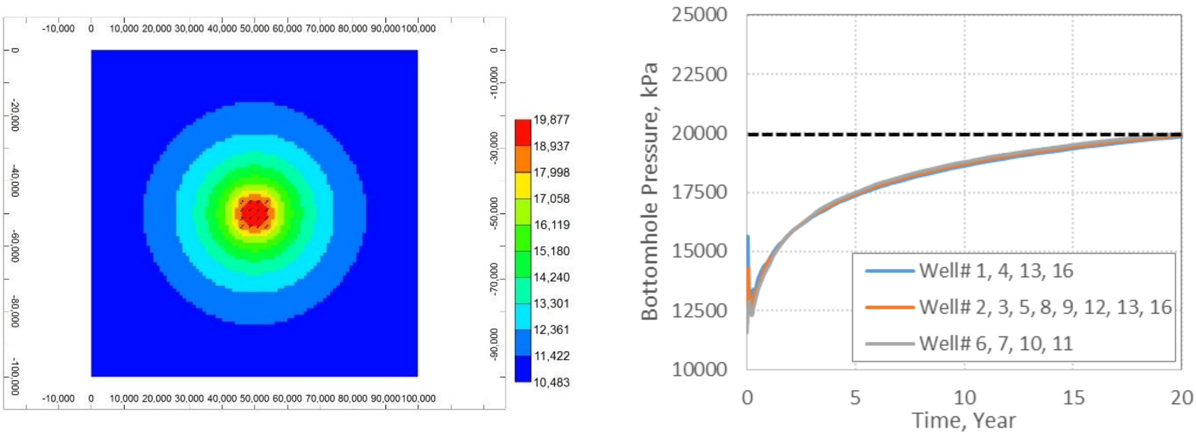
a) 1 well



b) 4 wells



c) 9 wells



d) 16 wells

Figure 2: Pressure distributions and bottom-hole pressures for open boundary condition after 20 years of constant injection at a depth of 1000 m.

Figures 3 and 4 show the maximum capacity for closed and open boundary problems versus the number of injectors. The open boundary reservoirs have a much larger storage capacity. The storage capacity of reservoirs remains constant after a specific number of injectors is reached.

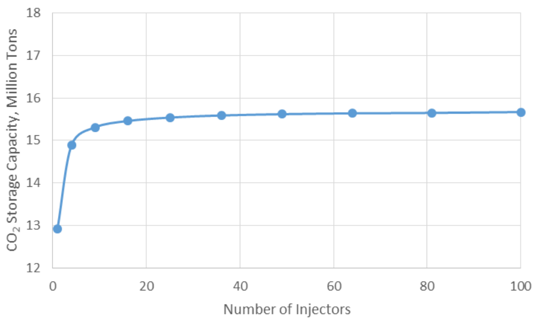


Figure 3: CO_2 capacity for 20 years of injection versus number of injectors using closed boundary condition at a depth of 1000 m.

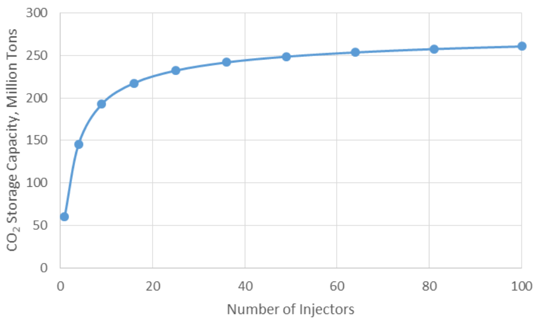
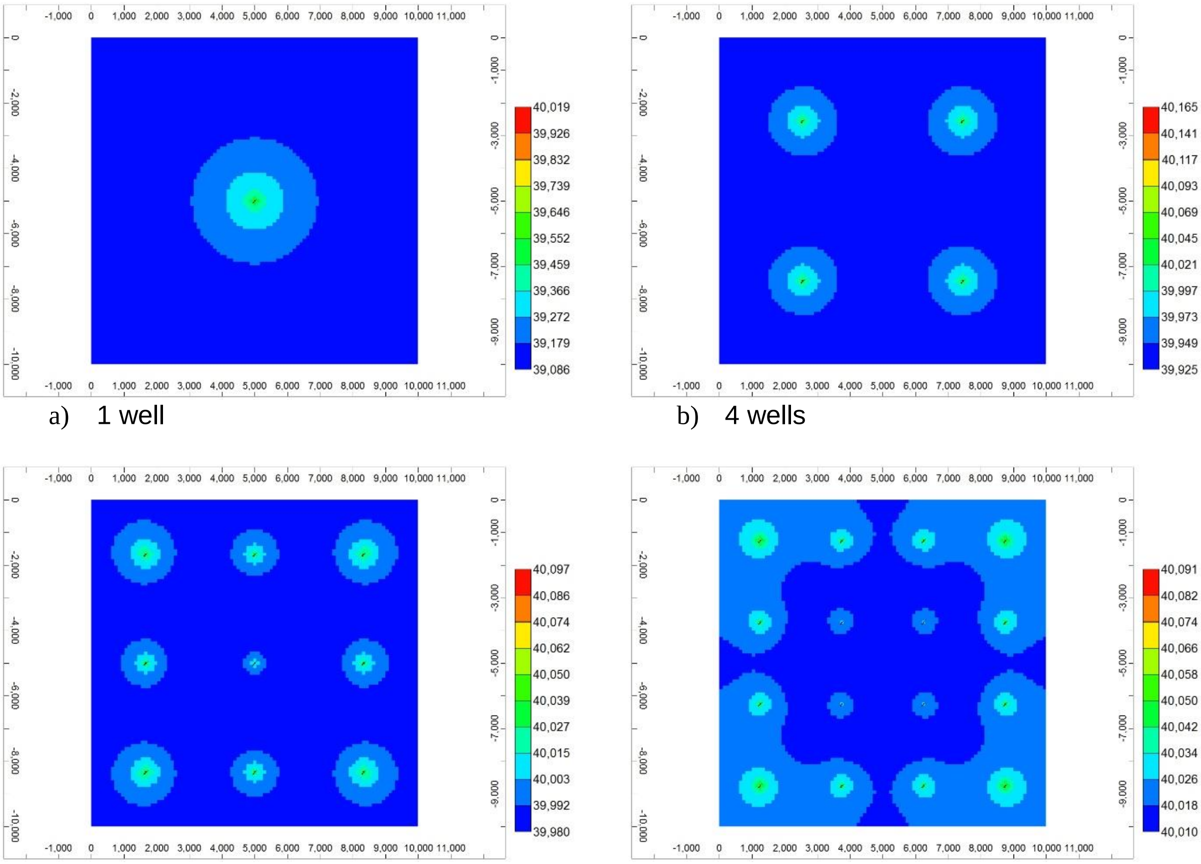


Figure 4: CO_2 capacity for 20 years of injection versus number of injectors using open boundary condition at a depth of 1000 m.

The same comparative study was performed for a reservoir at a depth of 3,000 m. The initial temperature and pressure in this study were 90 ˚C and 30 MPa, respectively. It was assumed that the maximum pressure in the reservoir would be 40 MPa after 20 years of injection. Figures 5 and 6 show the final pressure distribution obtained by simulation. Again, the results of the closed boundary case are closer to the results of EASiTool than are the results of the open boundary case.



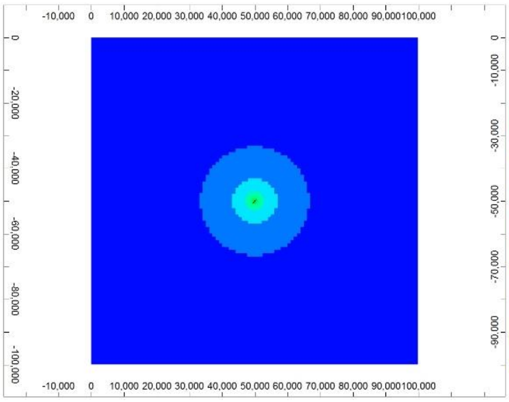
a) 1 well

b) 4 wells

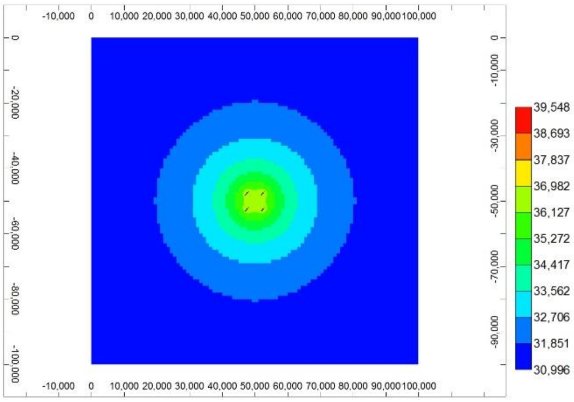
c) 9 wells

d) 16 wells

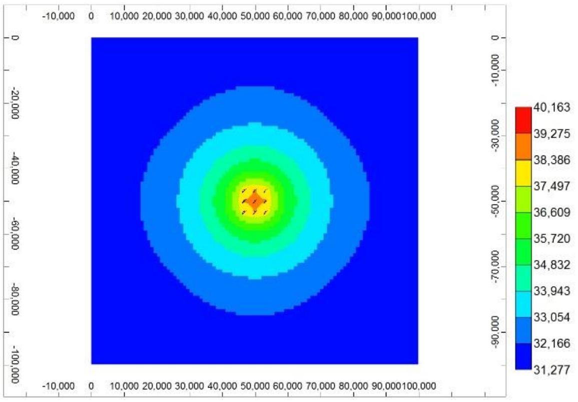
Figure 5: Pressure distribution for closed boundary condition after 20 years of constant injection at a depth of 3,000 m.



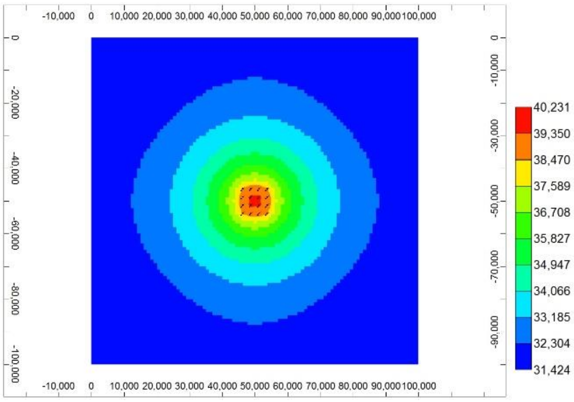
a) 1 well



b) 4 wells



c) 9 wells



d) 16 wells

Figure 6: Pressure distribution for open boundary condition after 20 years of constant injection at a depth of 3,000 m.

Figures 7 and 8 show the maximum capacity for closed and open boundary problems versus the number of injectors. It is observed that the open boundary reservoirs have a much larger storage capacity.

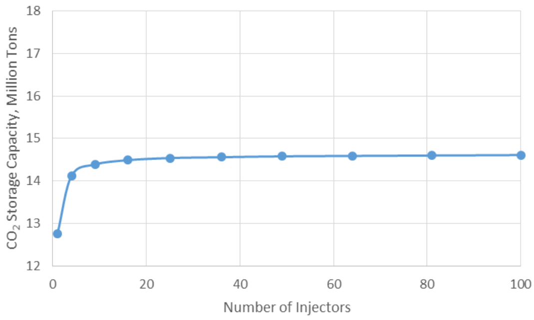


Figure 7: CO_2 capacity for 20 years of injection versus number of injectors using closed boundary condition at a depth of 3,000 m.

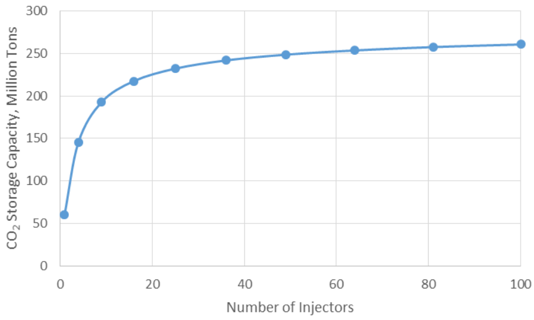


Figure 8: CO_2 capacity for 20 years of injection versus number of injectors using open boundary condition at a depth of 3,000 m.

EASiTool assumes that the reservoir is square, flat, and horizontal. The effect of reservoir shape and structure on the EASiTool estimations was studied. An anticline model was used for reservoir simulation with the average properties of the reservoir used as input for EASiTool. Estimated injection rates by EASiTool were also used as input for reservoir simulation. Tables 4 and 5 show the average properties of the anticline reservoir and the simulation parameters. Figure 9 shows the pressure distribution in the reservoir after 10 years of injection using 16 injectors. The simulation predicts the maximum pressure of 24.07 MPa, which is very close to the target pressure of 25 MPa.

Table 4: Properties of Anticline Reservoir

Reference pressure, MPa	16.55
Reference depth, m	1750
Initial temperature, ˚C	40
Average thickness, m	24.39
Salinity, kg/mol	0
Porosity	0.2
Permeability, mD	100
Rock compressibility, 1/Pa	5.0E-10
Reservoir area, km^2	42.87
Basin area, km^2	42.87
Boundary condition	Closed

Table 5: Simulation Parameters

Simulation time, year	20
Injection well radius, m	0.1
Maximum injection pressure, MPa	25

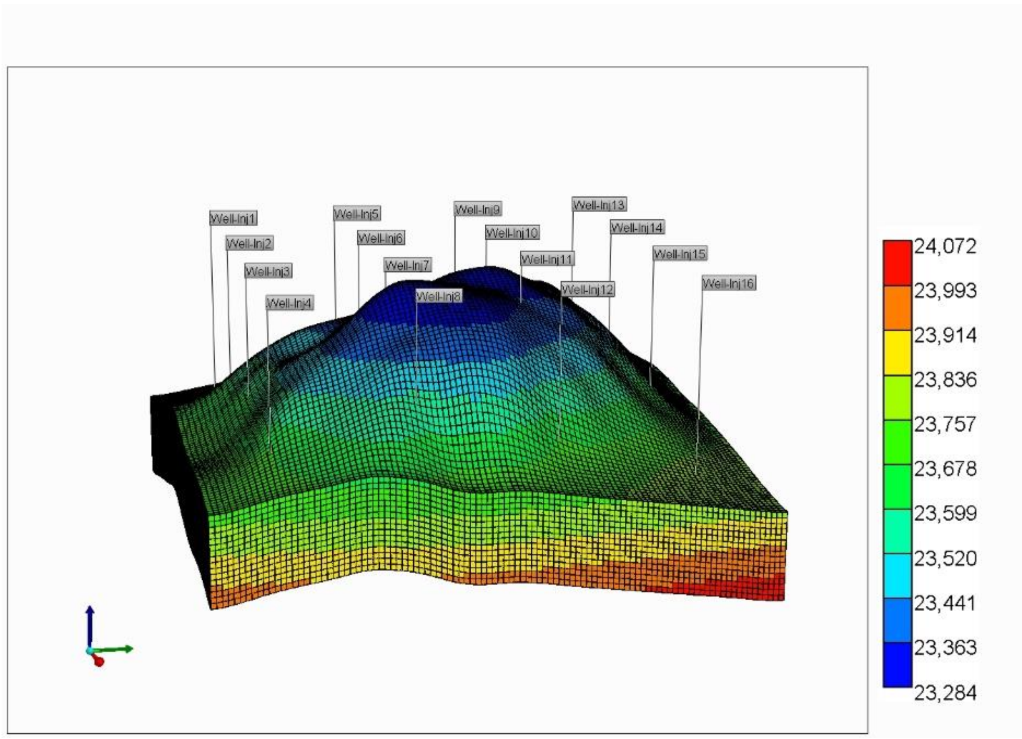


Figure 9: Pressure distribution after 20 years of injection using 16 injectors.

EASiTool assumes that the reservoir is homogeneous. The effect of reservoir heterogeneity on the EASiTool estimations was studied. The same anticline in Figure 9 was used for reservoir simulation using the average properties and simulation parameters of Tables 4 and 5. Two realizations for permeability distribution were prepared with Petrel software. Figures 10 and 11 show the histograms of the two realizations. The second model is more heterogeneous than the first.

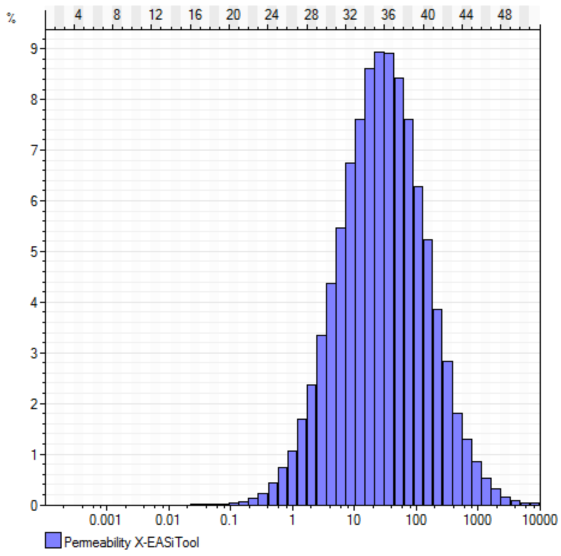


Figure 10: Histogram of permeability for first realization.

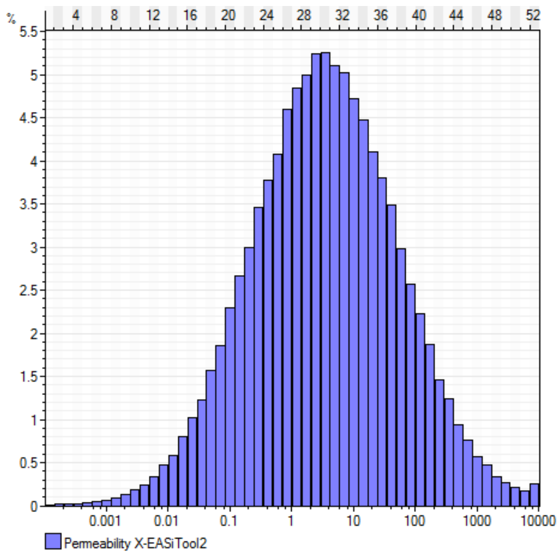


Figure 11: Histogram of permeability for second realization.

Figures 12 and 13 show the permeability distributions of the respective models. The estimated injection rates by EASiTool were used as input for reservoir simulation for both models.

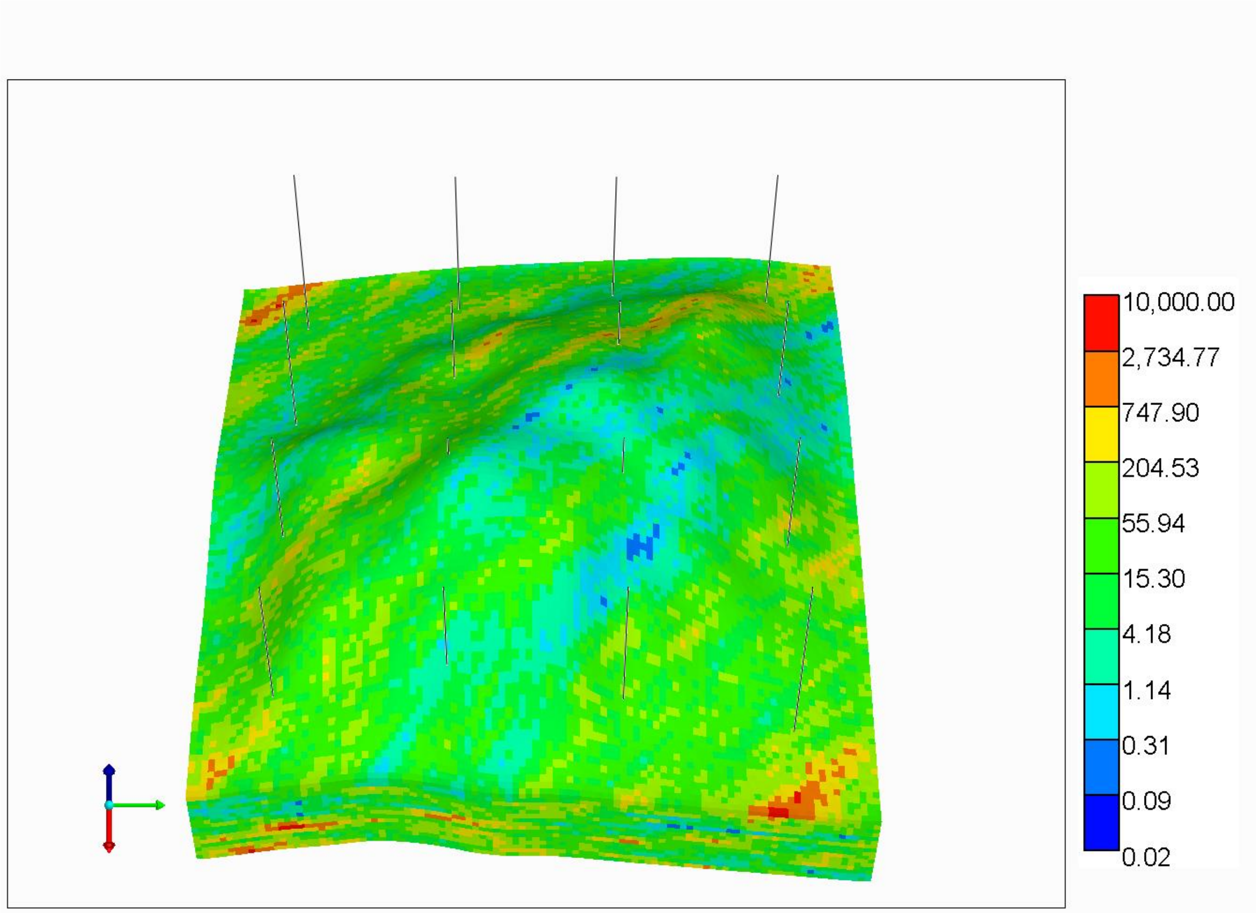


Figure 12: Permeability distribution for first realization.

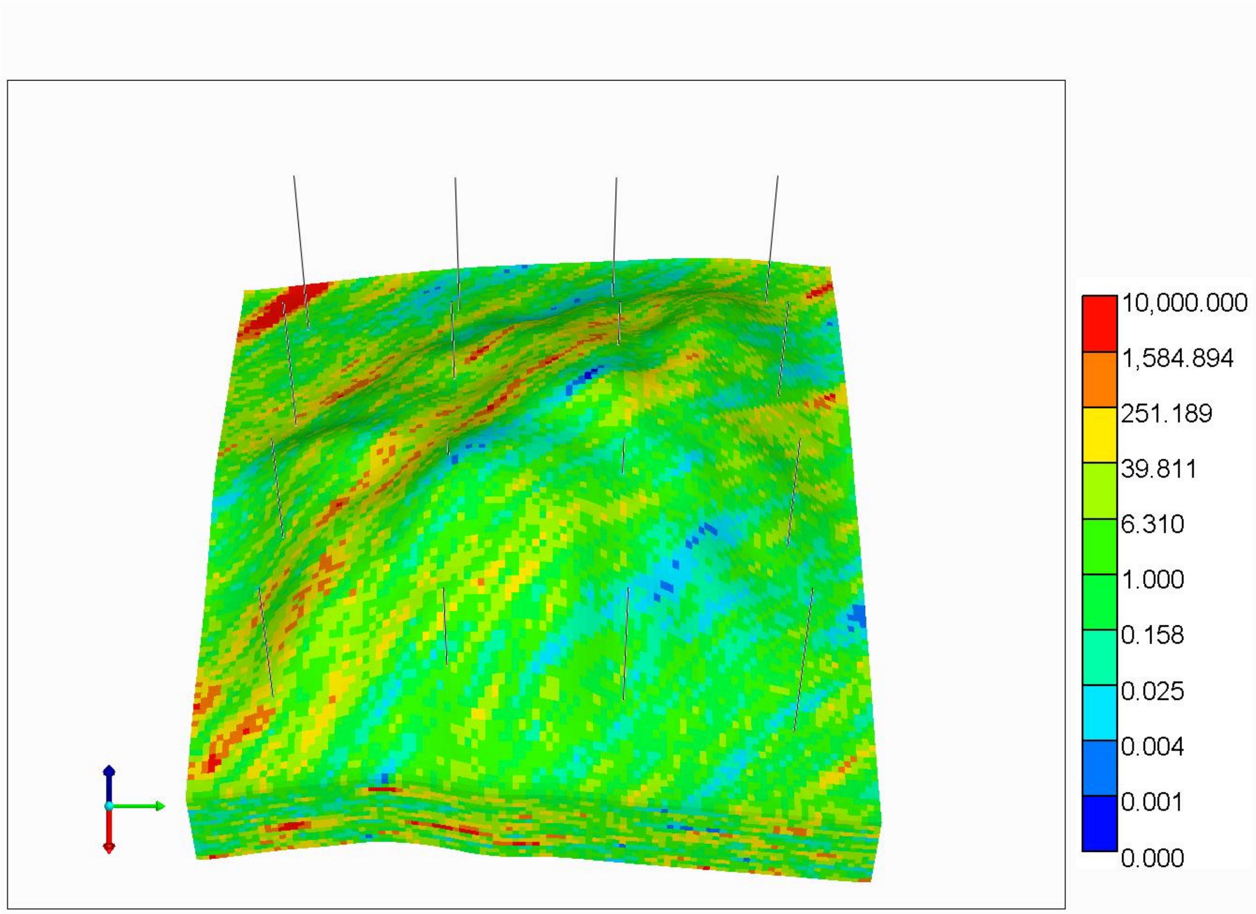


Figure 13: Permeability distribution for second realization.

Figures 14 and 15 show the pressure distribution in the reservoir after 20 years of injection using 16 injectors. The simulation predicts the maximum pressure of 25.07 and 25.51 MPa, respectively, which are very close to the target pressure of 25 MPa.

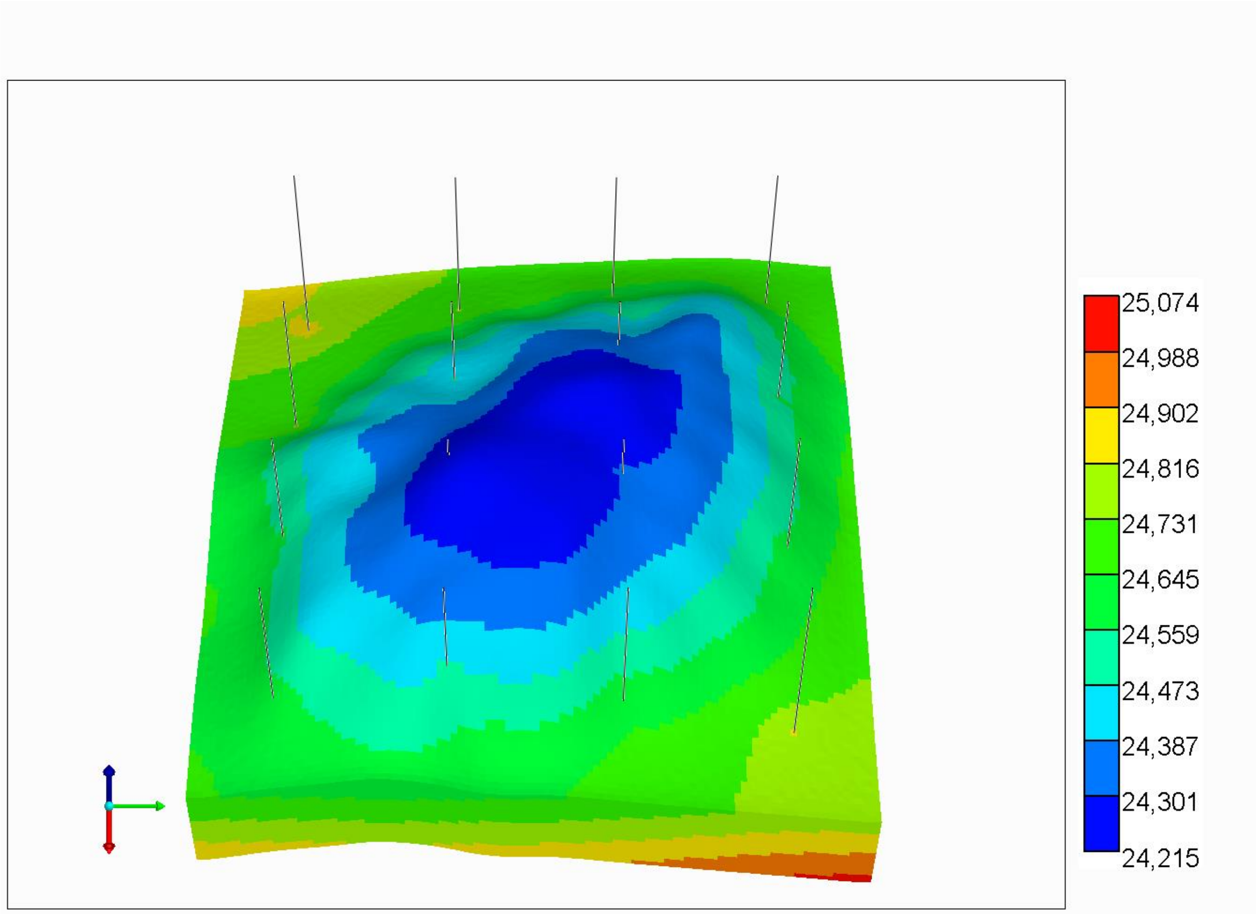


Figure 14: Pressure distribution for first realization.

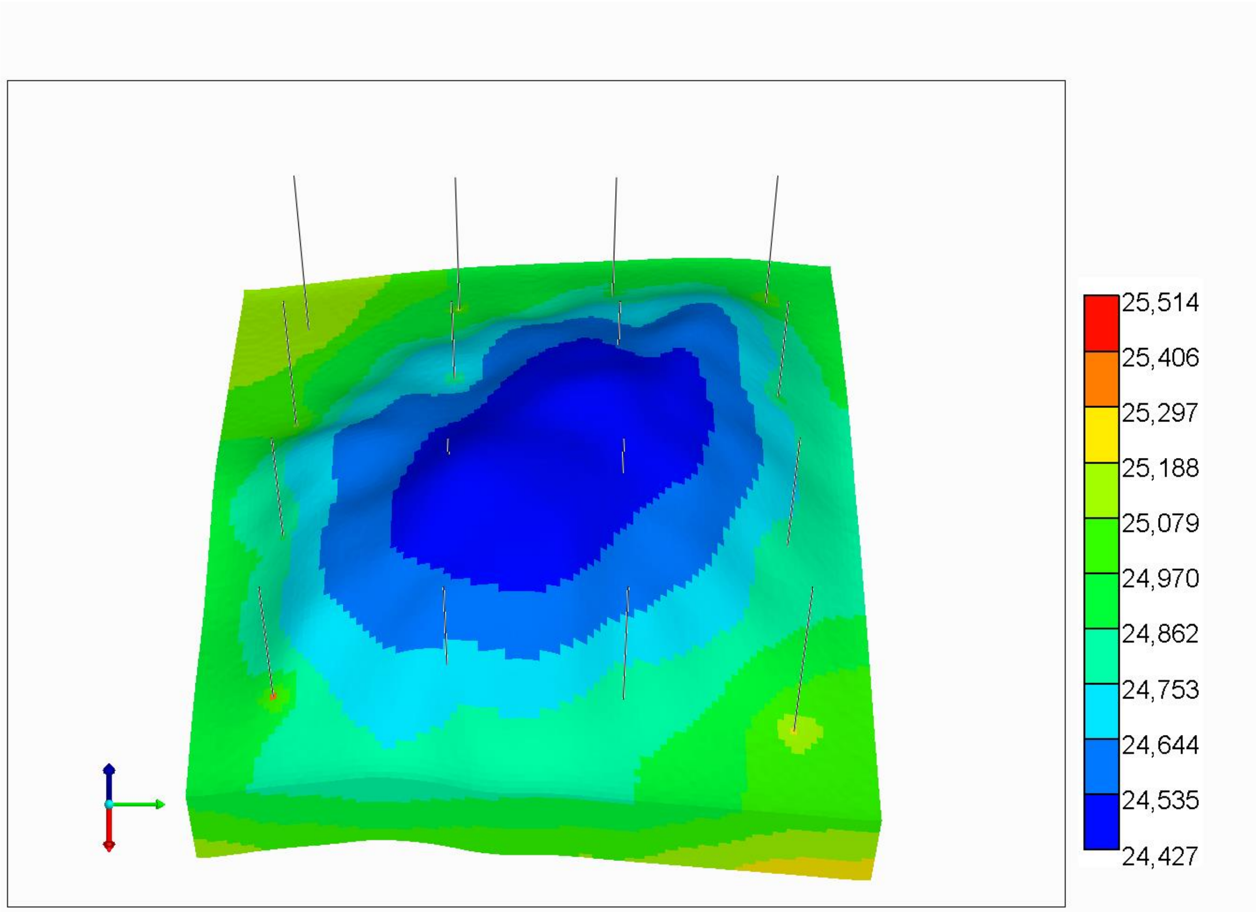


Figure 15: Pressure distribution for second realization.

Figures 16 shows the results of simulation using nine injectors and four extractors. The initial pressure is 20.0 MPa. The final target bottom-hole pressures are 25.0 and 20.0 MPa for the injectors and extractors, respectively. Figure 16 shows the distribution of reservoir pressure after 20 years. In addition, Figure 17 shows the bottom-hole pressure of one injector and one extractor. The final reservoir pressures are 25.1 and 20.1 MPa which are very close to the target pressures of 25.0 and 20.0 MPa.

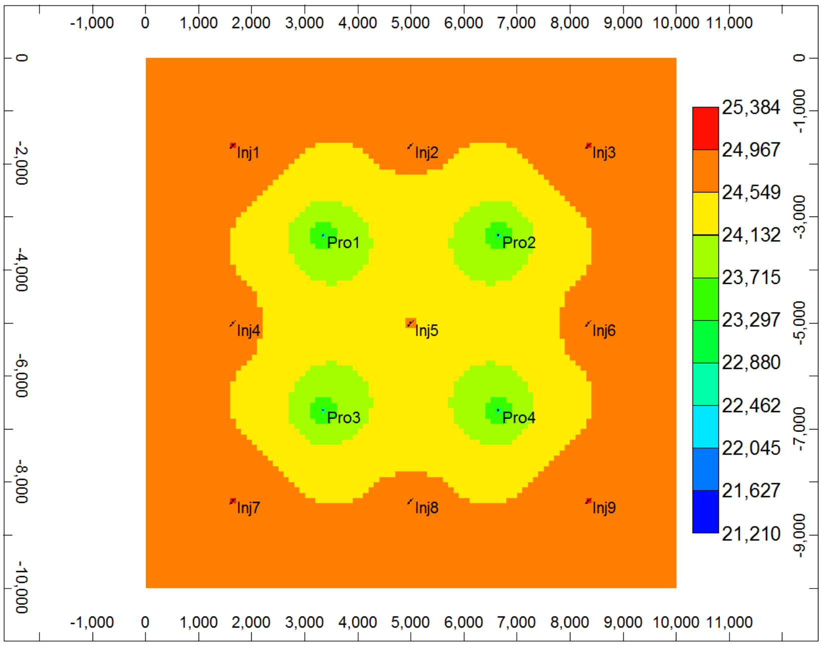


Figure 16: Pressure distribution throughout the aquifer after 20 years using nine injectors and four extractors.

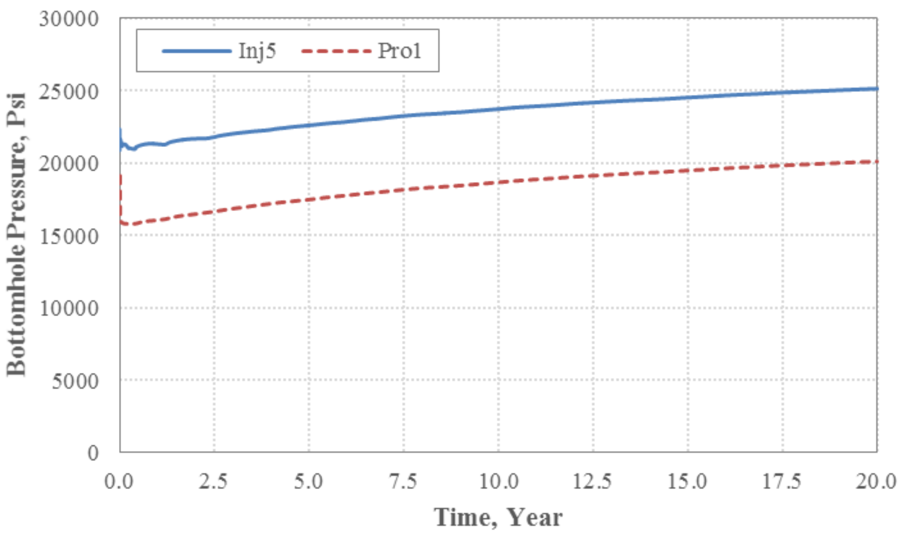


Figure 17: Bottom-hole pressure of injector #5 and extractor #1 versus time.

Figures 18 and 19 show the results of simulation for 16 injectors and 4 extractors. The initial pressure is 20.0 MPa and the target bottom-hole pressure of injectors and extractors are 25.0 and 20.0 MPa, respectively. The predicted bottom-hole pressures after 20 years using numerical simulations are very close to the target pressures.

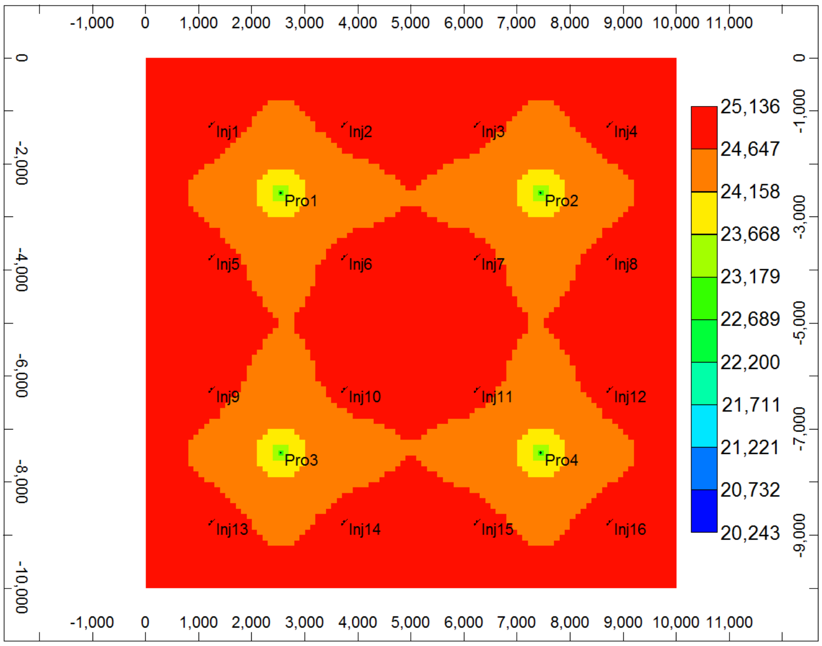


Figure 18: Pressure distribution throughout the aquifer after 20 years using 16 injectors and 4 extractors.

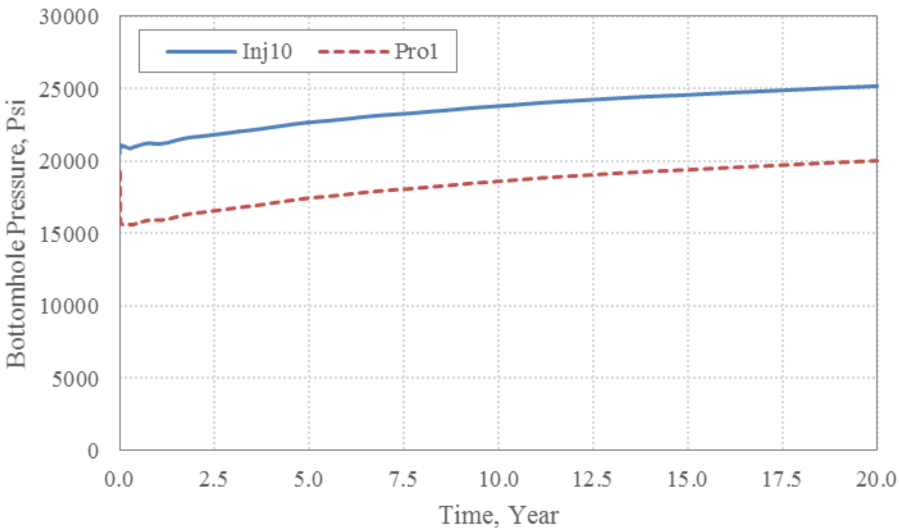


Figure 19: Bottom-hole pressure of injector #10 and extractor #1 versus time.

Table 6 summarizes the reservoir parameters for a general example with 30 injectors and 8 extractors.

Table 6: Reservoir Parameters

Initial pressure, MPa	20
Initial temperature, ˚C	65
Thickness, m	100
Salinity, kg/mol	0
Porosity	0.2
Permeability, mD	100
Rock compressibility, 1/Pa	5.0E-10
Basin X, km	12
Basin Y, km	8
Boundary Condition	Closed

The relative permeability parameters for this problem is the same as the ones presented in Table 2. Table 7 summarizes the simulations parameters.

Table 7: Simulation Parameters

Simulation time, year	10
Injection well radius, m	0.1

Table 8 summarizes the well locations and operating constraints for all injectors and extractors.

Table 8: Well Locations and Operating Constraints

Well Number	Well X (m)	Well Y (m)	Injection Rate (Ton/day)	Extraction Rate (m^3/day)	Max Injection Pressure (Mpa)	Min Extraction Pressure (Mpa)	Well Type (0 for Injector/1 for Extractor)
1	1790	5390	250	0	35	20	0
2	2090	5070	200	0	35	20	0
3	1650	4870	200	0	35	20	0
4	2110	4530	150	0	35	20	0
5	1510	4310	150	0	35	20	0
6	2090	3990	250	0	35	20	0
7	1450	3710	200	0	35	20	0
8	2070	3450	250	0	35	20	0
9	1350	3150	200	0	35	20	0
10	2790	2990	100	0	35	20	0
11	1390	2590	300	0	35	20	0
12	2910	2450	200	0	35	20	0
13	2630	1890	350	0	35	20	0
14	2030	1410	500	0	35	20	0
15	1630	1930	150	0	35	20	0
16	1850	3010	200	0	35	20	0
17	2430	2630	250	0	35	20	0
18	2090	2130	300	0	35	20	0
19	9050	3010	350	0	35	20	0
20	8770	3450	150	0	35	20	0
21	9310	3470	200	0	35	20	0
22	8690	3910	250	0	35	20	0
23	9530	3890	100	0	35	20	0
24	8730	4410	100	0	35	20	0
25	9150	4790	150	0	35	20	0
26	9830	4650	200	0	35	20	0
27	10450	4630	150	0	35	20	0
28	10190	5150	200	0	35	20	0
29	10590	5390	150	0	35	20	0
30	9210	4250	300	0	35	20	0
31	2170	1810	0	200	35	20	1
32	1890	2530	0	200	35	20	1
33	2330	3030	0	200	35	20	1
34	1770	3870	0	200	35	20	1
35	1770	4590	0	200	35	20	1
36	9030	3730	0	200	35	20	1
37	9390	4570	0	200	35	20	1
38	10190	4790	0	200	35	20	1

Table 9 summarizes the output file for the above example.

Table 9: Excel Output File

WellNumber	WellX_m	WellY_m	InjRate_TonPerDay	ExtRate_CubicMeterPerDay	Prssure_MPa	Prssure_Criteria
1	1790	5390	250	0	33.43482	P
2	2090	5070	200	0	33.45416	P
3	1650	4870	200	0	33.45067	P
4	2110	4530	150	0	33.46696	P
5	1510	4310	150	0	33.45002	P
6	2090	3990	250	0	33.57468	P
7	1450	3710	200	0	33.52467	P
8	2070	3450	250	0	33.61311	P
9	1350	3150	200	0	33.54522	P
10	2790	2990	100	0	33.49868	P
11	1390	2590	300	0	33.60333	P
12	2910	2450	200	0	33.56705	P
13	2630	1890	350	0	33.65188	P
14	2030	1410	500	0	33.68509	P
15	1630	1930	150	0	33.49465	P
16	1850	3010	200	0	33.59129	P
17	2430	2630	250	0	33.62914	P
18	2090	2130	300	0	33.64285	P
19	9050	3010	350	0	33.41074	P
20	8770	3450	150	0	33.31918	P
21	9310	3470	200	0	33.32449	P
22	8690	3910	250	0	33.38588	P
23	9530	3890	100	0	33.24537	P
24	8730	4410	100	0	33.2718	P
25	9150	4790	150	0	33.25464	P
26	9830	4650	200	0	33.24743	P
27	10450	4630	150	0	33.14206	P
28	10190	5150	200	0	33.18715	P
29	10590	5390	150	0	33.09748	P
30	9210	4250	300	0	33.39318	P
31	2170	1810	0	200	33.3133	P
32	1890	2530	0	200	33.33027	P
33	2330	3030	0	200	33.33242	P
34	1770	3870	0	200	33.29281	P
35	1770	4590	0	200	33.23397	P
36	9030	3730	0	200	33.09923	P
37	9390	4570	0	200	33.0445	P
38	10190	4790	0	200	32.95544	P

Figures 20 and 21 shows the final pressure contour and CO_2 plume extensions.

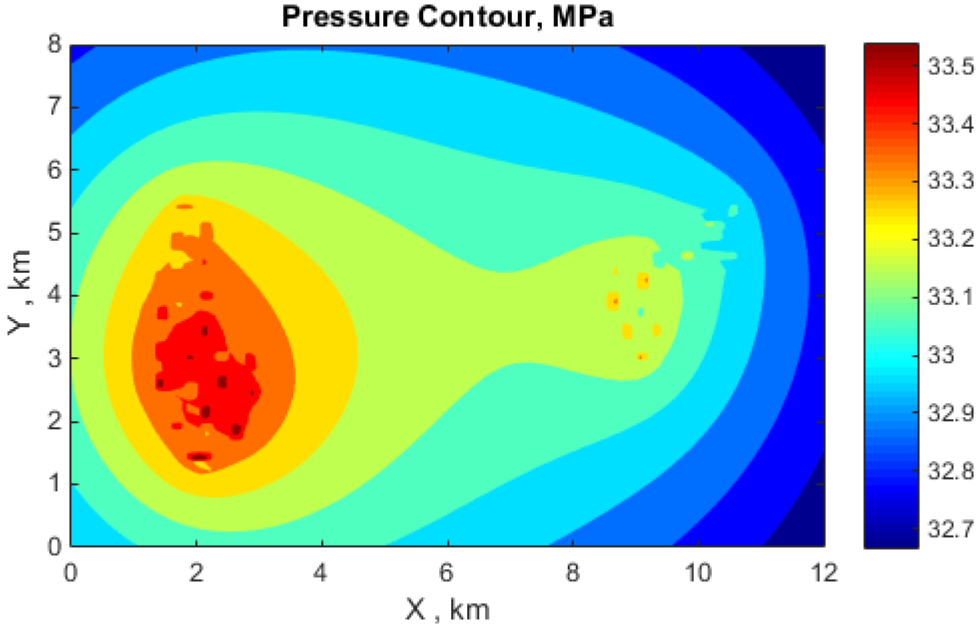


Figure 20: Pressure contour after 10 years of injection and extraction.

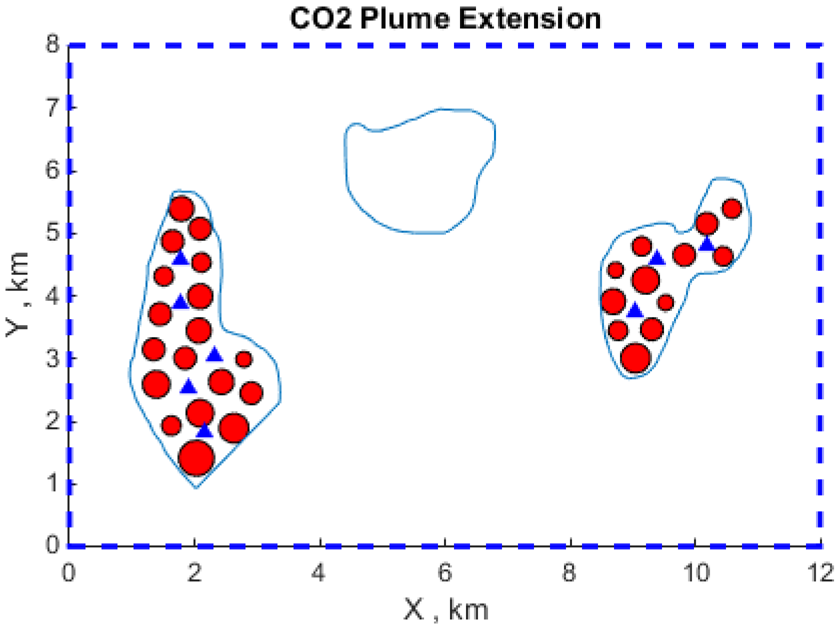


Figure 21: CO_2 plume extensions after 10 years of injection and extraction.

Figures 22 and 23 show the numerical simulation results for this general case. The results show that the predicted pressure and plume extension by EASiTool is very close the predictions by numerical simulation.

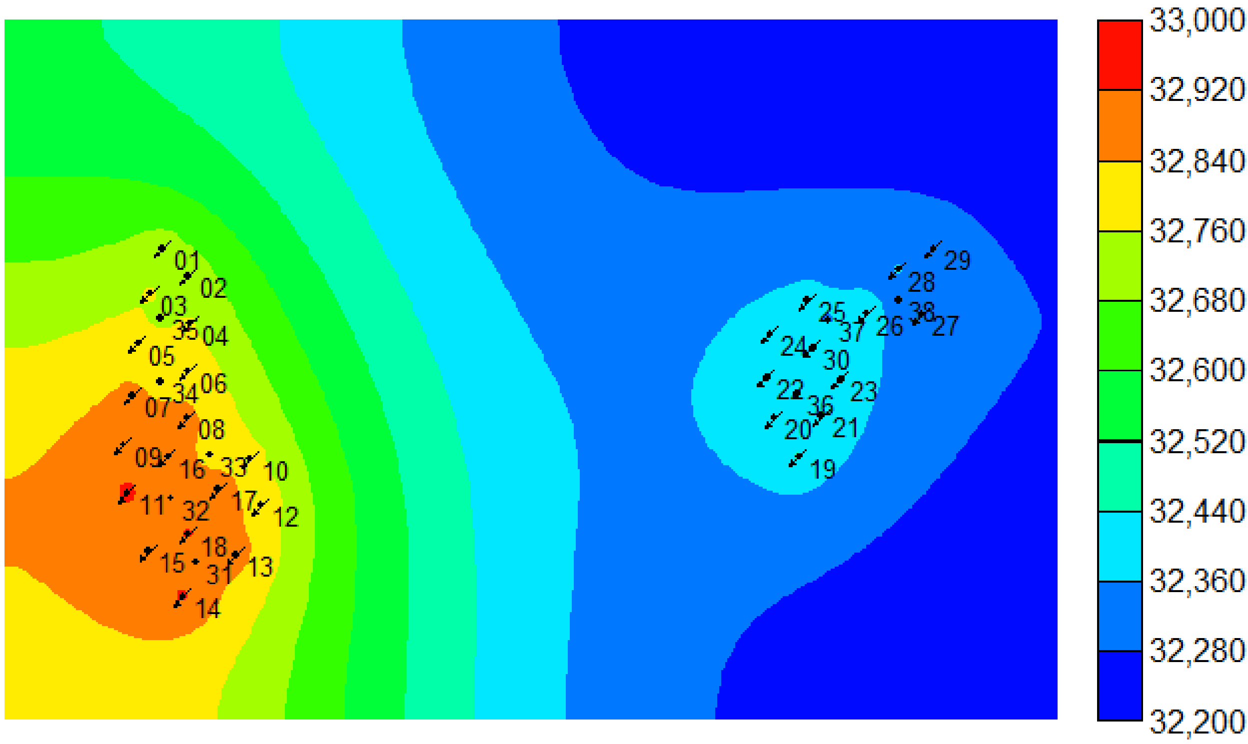


Figure 22: Pressure contour by numerical simulation.

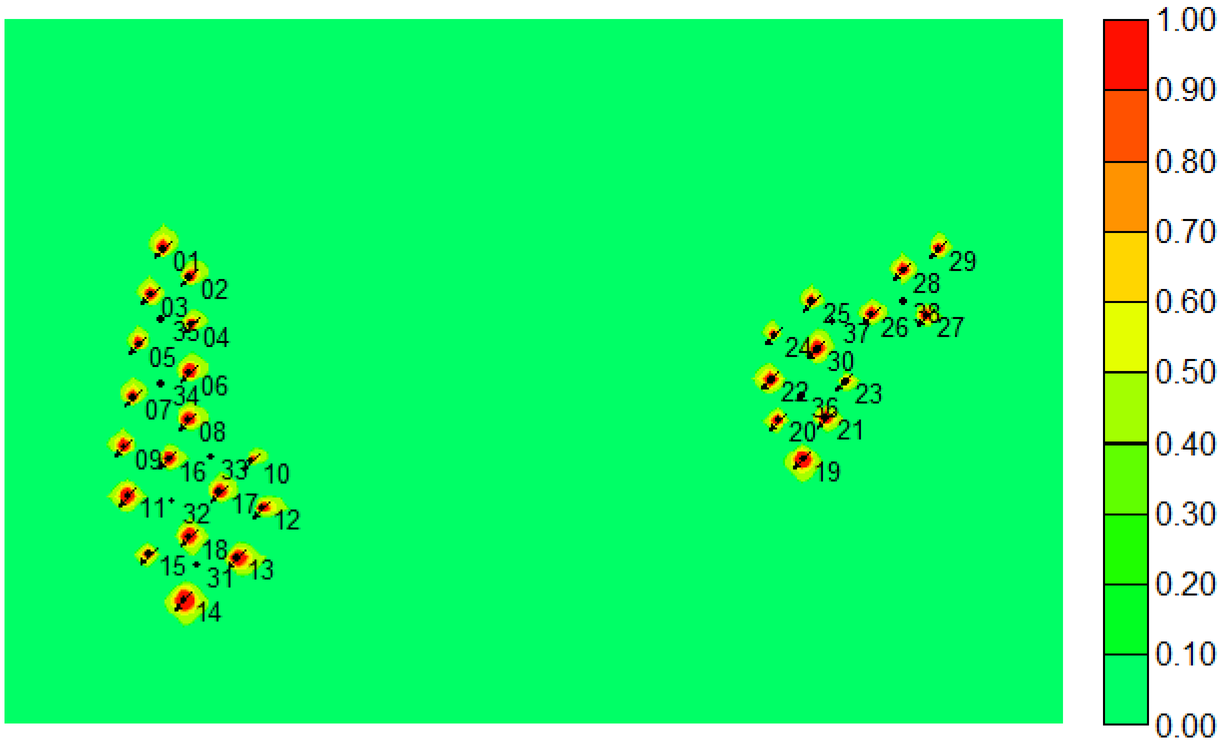


Figure 23: Gas saturation by numerical simulation.

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