BELL CREEK TEST SITE – SIMULATION REPORT

Plains CO_2 Reduction (PCOR) Partnership Phase III
Task 9 – Deliverable D66

Prepared for:

Andrea T. McNemar

National Energy Technology Laboratory
U.S. Department of Energy
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

DOE Cooperative Agreement No. DE-FC26-05NT42592

Prepared by:

Hui Pu
John A. Hamling
Jordan M. Bremer
Terry P. Bailey
Jason R. Braunberger
Jun Ge
Dayanand Saini
James A. Sorensen
Charles D. Gorecki
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

August 2011
Approved

2012-EERC-04-21

EERC DISCLAIMER

LEGAL NOTICE This research report was prepared by the EERC, an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy. Because of the research nature of the work performed, neither the EERC nor any of its employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the EERC.

DOE DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

NDIC DISCLAIMER

This report was prepared by the Energy & Environmental Research Center (EERC) pursuant to an agreement partially funded by the Industrial Commission of North Dakota, and neither the EERC nor any of its subcontractors nor the North Dakota Industrial Commission nor any person acting on behalf of either:

(A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

(B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the North Dakota Industrial Commission. The views and opinions of authors expressed herein do not necessarily state or reflect those of the North Dakota Industrial Commission

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

BELL CREEK TEST SITE – SIMULATION REPORT

EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership is working with Denbury Onshore LLC (Denbury) to evaluate the effectiveness of large-scale injection of carbon dioxide (CO_2) into the Bell Creek oil field for simultaneous CO_2 enhanced oil recovery (EOR) and long-term CO_2 storage. Discovered in 1967, the Bell Creek oil field in southeastern Montana has undergone primary production (solution gas drive), waterflooding, and two micellar–polymer pilot tests. An estimated 220 million barrels (MMbbl) of oil remains in the reservoir, with about 37.7% of the estimated 353 MMbbl of original oil in place (OOIP) having been produced to date. It is anticipated that 35 MMbbl of additional oil could be produced through CO_2 flooding in this field.

With the goal of providing a comprehensive assessment of CO_2 storage behavior and potential while supporting Denbury's EOR efforts, members of the PCOR Partnership have initiated a preliminary numerical simulation program to 1) characterize and model the study area using advanced geological modeling, 2) history-match Bell Creek static model parameters regarding pressure, volume, temperature (PVT) tests, address and predict minimum miscibility pressure, and 3) utilize predictive simulations to aid in the development of effective strategies for monitoring an integrated CO_2 EOR and long-term CO_2 storage project.

Some of the key results of this work include the following:

- PVT history matching between laboratory data and predicted results for three fluid samples are in general agreement. Results indicate that miscibility for oil samples can be achieved at approximately 2800 psia.

- A 3-D model was constructed using a stratigraphic framework, yielding a structural model into which rock and fluid petrophysical properties were populated. This 3-D geological model will be used as input for history matching and predictive reservoir simulations.

In order to validate the geological model, the next steps involve matching historic production and injection in the Bell Creek Field. After history matching, coupled and uncoupled predictive simulation will be used to better understand the long-term fate of the injected CO_2 and the performance of the CO_2 EOR operations. The results of the modeling and simulation program will be used to improve the efficiency of the CO_2 EOR project as well as develop a more effective monitoring program for simultaneous CO_2 storage.

BELL CREEK TEST SITE – SIMULATION REPORT

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC), is working with Denbury Onshore LLC (Denbury) to determine the effect of a large-scale injection of carbon dioxide (CO_2) into a deep clastic reservoir for the purpose of simultaneous CO_2 enhanced oil recovery (EOR) and CO_2 storage at the Bell Creek oil field, which is owned and operated by Denbury Onshore LLC (Denbury). A technical team that includes Denbury, the EERC, and others will conduct a variety of activities to determine the baseline reservoir characteristics and conduct predictive simulations of the CO_2 injection. This will facilitate assessment of various potential injection schemes, guide monitoring strategies, and determine the ultimate fate of injected CO_2. Denbury will carry out the injection and production operations, while the EERC will provide support for the site characterization, modeling and simulation, and integrated risk assessment and will aid in the development of the monitoring, verification, and accounting (MVA) plan to address CO_2 leakage risks and mitigation strategies.

The Bell Creek oil field in southeastern Montana is a significant hydrocarbon accumulation which lies near the northeastern corner of the Powder River Basin (Figure 1). Exploration and production activities for mineral and energy resources in the area over the last 55 years have yielded a significant amount of information about the geology of southeastern Montana and the northern Powder River Basin. Decades of oil and gas production through primary and secondary recovery (waterflood and polymer flood pilot tests) has resulted in reservoir decline and now leads to the planned implementation of tertiary recovery techniques, with CO_2 EOR as the foremost applicable technology. CO_2 will be delivered to the site via pipeline from the Lost Cabin gas plant where it is separated (and traditionally vented) from the process stream during natural gas refinement. The plant is located in Fremont County, Wyoming, and currently generates around 50 million cubic feet of CO_2 per day (Figure 1).

The Bell Creek CO_2 EOR and CO_2 storage project will provide a unique opportunity to develop a characterization and predictive modeling workflow for a complex, large scale (>1 million tons per year) combined CO_2 EOR and CO_2 storage operation in an active oil field. The baseline geological characterization and simulation work that will be conducted over the course of this project will also provide valuable data to support the design and implementation of an injection/production scheme for large-scale CO_2 EOR and storage at the Bell Creek oil field.

CO_2 will be injected into the oil-bearing sandstone reservoir in the Lower Cretaceous Muddy (Newcastle) Formation at a depth of approximately 4500 feet (1372 meters). CO_2

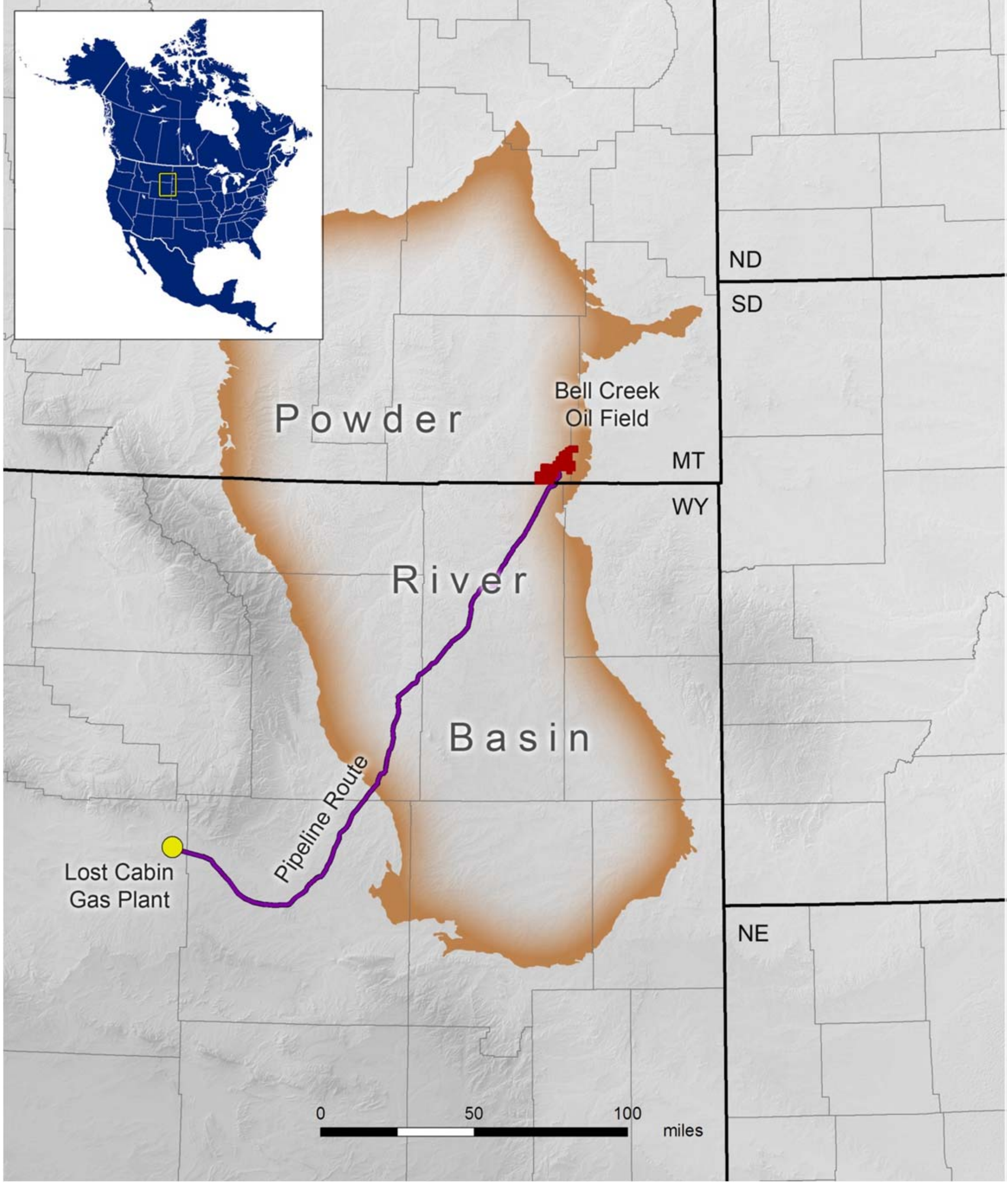


Figure 1. Map depicting the location of the Bell Creek oil field in relation to the Powder River Basin and the planned pipeline route to the site from the Lost Cabin gas plant.

injection will occur via completed wellbores in a staged approach across the field. It is expected that the reservoir will be suitable for miscible flooding conditions with an incremental oil production target of approximately 35 million barrels. The activities at the Bell Creek oil field will inject an estimated 1.1 million tons of CO_2 annually, much of which will be permanently stored.

Within the Bell Creek oil field, the Muddy Formation is dominated by high-porosity (~24%) and -permeability (~900 millidarcy) sandstones deposited in a near-shore marine environment (Encore Acquisition Company, 2009). The oil field is located on a shallow monocline with a 1° dip to the northwest and whose axis trends southwest to northeast for a distance of approximately 20 miles. Stratigraphically, the Muddy Formation in the Bell Creek oil field features an updip facies change from sand to shale that serves as a trap. The sand bodies of the reservoir are partially dissected and somewhat compartmentalized by intersecting shale-filled incisive erosional channels.

The overlying Upper Cretaceous Mowry Formation shale will provide the primary seal, preventing fluid migration to overlying aquifers and to the surface. On top of the Mowry Formation are several thousand feet of low-permeability shale formations, including the Belle Fourche, Greenhorn, Niobrara, and Pierre shales, which will provide redundant layers of protection in the unlikely event that the primary seal fails to prevent upward fluid migrations fieldwide (Figure 2).

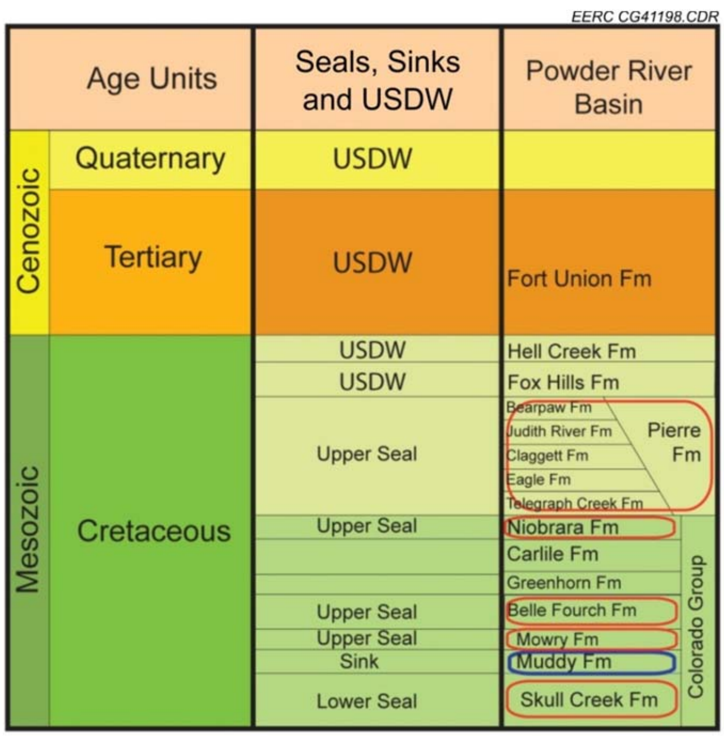


Figure 2. Late Cretaceous to Quaternary stratigraphic column of the Powder River Basin. Sealing formations are circled in red, and the primary sink formation is circled in blue. Formations bearing underground sources of drinking water (USDW) are also identified.

The EERC's modeling of the subsurface and predictive simulation activities will aid in understanding the behavior of injected CO_2 and reservoir fluids over the injection and postinjection project periods. Modeling and simulation are important for assessing reservoir sweep, CO_2 storage efficiencies, and potential out-of-zone fluid migrations. This type of assessment is an essential input to the integrated risk assessment and MVA plans, which in turn helps to ensure that the maximum benefit to the EOR process is achieved in a safe and efficient manner.

To meet project and simulation modeling goals, a 3-D geologic model was constructed with pertinent reservoir simulation properties. These attributes were collected and assigned based on literature review of geologic reports, special core analysis, fluid analysis, PVT testing, and well logs. These data enabled calculations regarding the impact of current reservoir conditions on miscibility, flow dynamics, and other simulation values. To this point, the simulation model has been constructed and will be history matched with available production data and validated by data collected during the monitor well installation in fall 2011. It is also expected that geomechanical properties will be incorporated into the simulation model to assess the impact and risk of overpressurization of the reservoir as well as provide on upper limit for injection pressure.

PURPOSE

The PCOR Partnership is developing a philosophy which integrates site characterization, modeling, simulation, risk identification, and MVA strategies into an iterative process to produce meaningful results for large-scale CO_2 storage projects (Figure 3). Elements of any of these activities play a crucial role in the understanding and development of the others. The modeling and simulation activities described in this report were developed to 1) identify areas where more site characterization data is needed, 2) aid in the identification of potential subsurfaces risks such as out of zone fluid migration, and 3) help in the development of effective monitoring strategies. This integrated process will be iterated and refined through each incremental stage of the project from initial planning, to injection and through post-closure.

The EERC's modeling of the subsurface aids in understanding and predicting the behavior of the injected CO_2 and reservoir fluids over the injection and postinjection period. The simulation work, in turn, is a highly valuable tool for assessing scenarios of fluid migration within the reservoir and the potential for out-of-zone fluid migration. Additionally, simulation activities provide a means to evaluate the efficiency and applicability of various injection strategies and parameters related to both CO_2 storage and CO_2 EOR.

This type of assessment is an essential input for risk identification and to guide MVA strategies, as it lays the foundation for a project-specific, risk-based, goal-oriented MVA plan. The goal of the MVA plan is to effectively monitor the behavior of the CO_2 in the subsurface, the reservoir, and reservoir fluids to help ensure that the maximum benefit to the EOR process is achieved in a safe and efficient manner. Accurate simulations allow for targeted deployment of MVA data acquisitions at optimal geographic locations and time intervals to maximize the knowledge gained. The results and experience gained at the Bell Creek oil field will provide insight and knowledge that can be directly and readily applied to similar projects within the PCOR Partnership region and throughout the world.

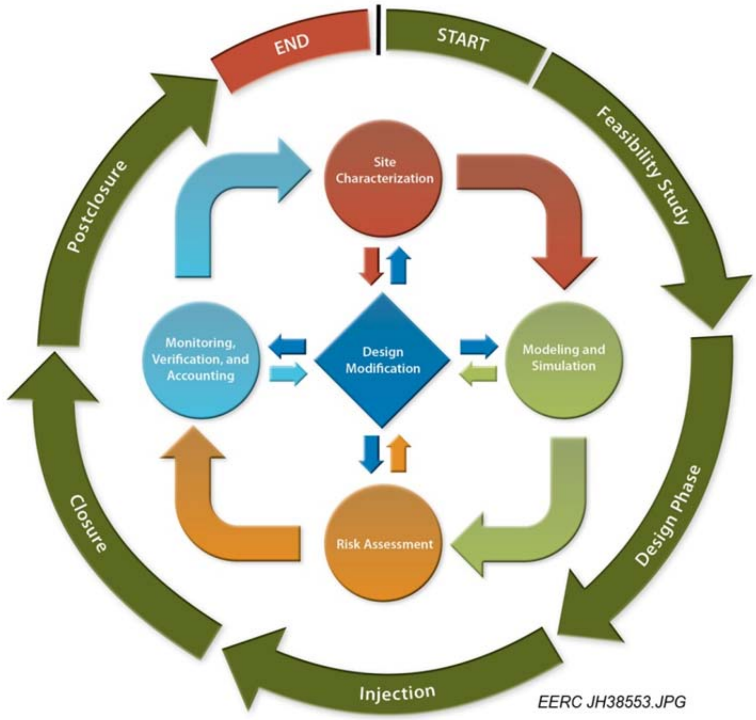


Figure 3. Project elements of the Bell Creek CCS project. Each of these elements feeds into another, iteratively improving results and efficiency of evaluation.

SCOPE OF WORK

The Muddy Formation sandstone of the Bell Creek reservoir was geologically modeled in order to evaluate the efficiency of large-scale CO_2 injection for simultaneous CO_2 EOR and CO_2 storage. Specifically, a geologic model was created to be utilized as framework for simulation activities geared toward addressing fluid migration pathways and to predict the ultimate fate of CO_2 which is expected to remain in the subsurface environment permanently. Numerical simulation efforts provide statistical prediction of CO_2 propagation in the subsurface, which in turn allows for targeted monitoring activities and a means of theoretically evaluating various injection scenarios for oil recovery and CO_2 storage. In order to fully evaluate both current and anticipated reservoir conditions, original oil in place (OOIP), incremental production assessments, and the ultimate fate of injected CO_2, extensive data reconnaissance was performed. Available data were analyzed, interpreted, and incorporated into the 3-D static geologic model to represent reservoir properties in order to provide a solid groundwork for simulation activities.

In preparation for CO_2 EOR, the field is currently undergoing active water injection to increase reservoir pressure to the expected miscibility pressures which have been calculated to be between 2700 to 2800 psi. A baseline CO_2-monitoring and characterization program is currently under development to establish preinjection pressures, fluid saturations, and reservoir properties in order to reduce the uncertainty in the geologic model.

3-D GEOLOGIC MODELING

Data reconnaissance activities were performed in order to acquire pertinent reservoir characterization data for the Bell Creek oil field. Because of the historic oil and gas activity within the field, an abundance of vintage geologic data exists in the form of geophysical well logs, lithology descriptions from well files, geologic maps, core data analysis, and cross sections. This data aided in selecting stratigraphic tops across the study area. In order to create a structural framework, stratigraphic tops must be picked for each zone of interest. This is primarily accomplished by analyzing geophysical well logs and incorporating other applicable geologic data, ultimately assigning a depth value to each top.

Advanced 3-D geologic modeling utilizing Schlumberger Petrel® software was conducted in order to characterize the geologic framework of the Muddy Formation within the geologic model boundary which is underlain by Skull Creek shale and overlain by Mowry shale. The study area encompasses the Phase 1 area and portions of Phase 2, 3 and 7 areas so as to engage surrounding data and eliminate extrapolation edge effects experienced when only using data contained within a given area (Figure 4). The 3-D geologic model was constructed to incorporate a distribution of geological and geophysical properties, commonly referred to as petrophysical properties. These properties were geostatistically assigned throughout the model, including the following:

- Total porosity
- Shale volume
- Effective porosity
- Net-to-gross ratio,
- Absolute permeability
- Water saturation
- Formation pressure
- Formation temperature

The geologic framework and assigned properties contained within the geologic model are necessary components for flow simulations which aid in estimating CO_2 storage and EOR efficiencies, estimating OOIP and incremental oil recoveries, and provide a means of enhancing the monitoring program through targeted monitoring equipment deployments.

Stratigraphic Framework

The Muddy Formation in the Bell Creek Field area consists of four distinct lithofacies, which were assigned structure and variability according to observed properties and trends in available data. In ascending order, these depositional sequences are designated as “Rozet shale,”

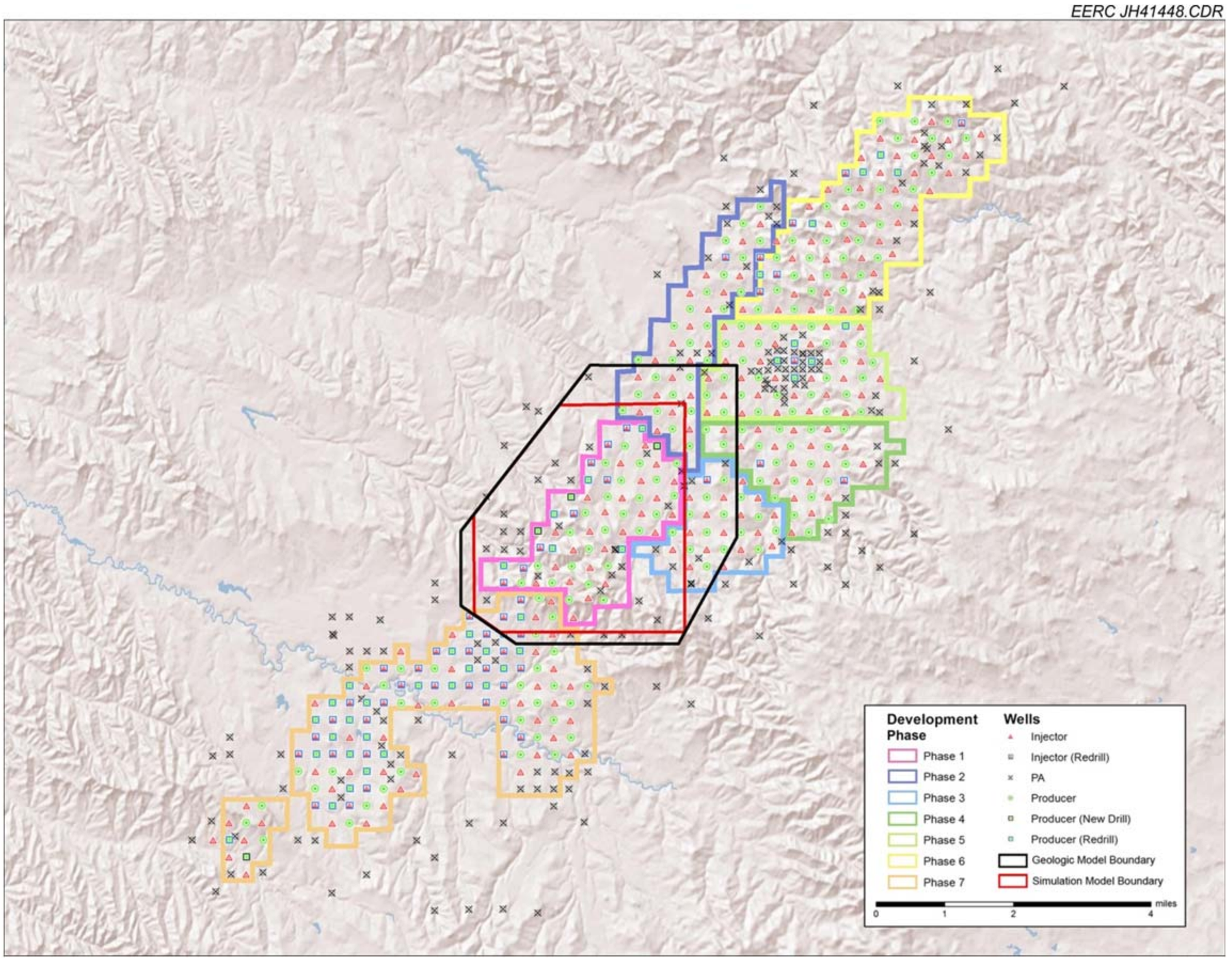


Figure 4. Map showing the geologic model boundary (black), the simulation model boundary (red) and their relation to the planned Bell Creek project development phases.

the "Bell Creek sand," the "coastal plain," and "Springen Ranch shale" (Figure 5). For the, geologic model, the Bell Creek sequence was further subdivided into three separate but connected producing zones: BC10, BC20, and BC30, corresponding to three previously identified barrier bar sequences in the field (Figure 6). The Bell Creek subdivisions were implemented in order to model and assess compartmentalization in the reservoir caused by short-scale transgressive/regressive events, which led to deposition of thin layers of low-permeability rock in some areas. Subdivision also enables finer-scale property prediction based on more focused and geostatistically applicable rock.

Following data preparation and analysis, over 1000 formation subunit tops were picked from analysis on 154 wells within the model boundary. The stratagraphic tops were used to generate surfaces representing intervals of interest containing geologically similar reservoir properties. A total of seven surfaces were produced for the 3-D geologic model: Springen Ranch, coastal plain, Bell Creek (BC)10, BC20, BC30, Rozet, and a basal surface. The Springen Ranch and basal surfaces were assigned arbitrary thicknesses so as to not incorporate several hundred feet of nonrelevant tight rock.

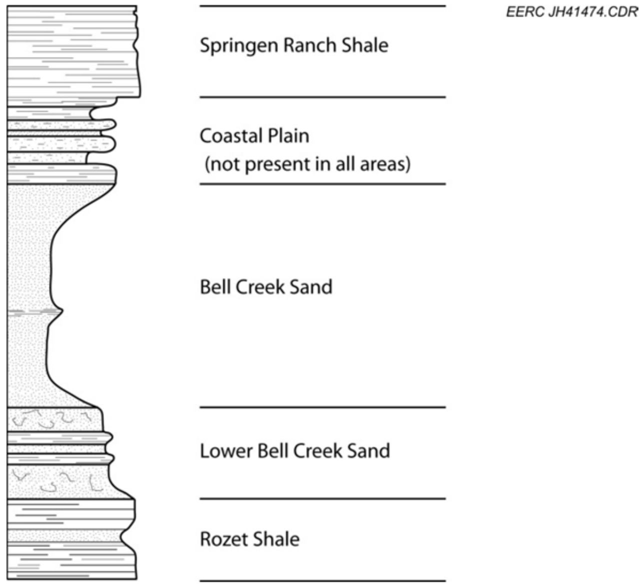


Figure 5. Generalized lithology and stratigraphic zones chosen for the Bell Creek static model.

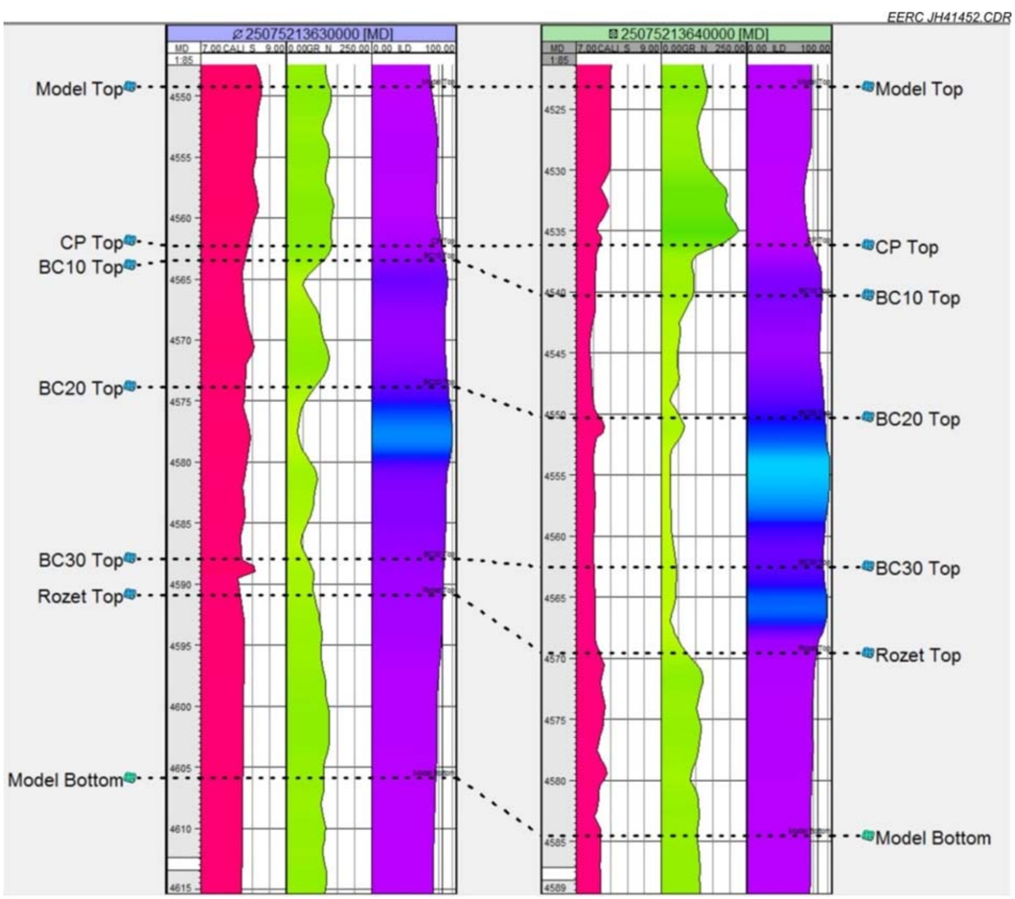


Figure 6. Type log including the seven picked stratigraphic tops. The first column from left to right is caliper followed by gamma ray and resistivity.

Areas exist within the geologic model where pressure compartmentalization and sparse well log data show that the Bell Creek sand has been completely eroded away, resulting in a network of deep incised valleys, which were later filled with tight marine sediments (Figure 7). Definition of these barriers will be imperative to the design of the injection process and to analyze long-term reservoir flow effects. History-matching practices will aid in defining the impact of the incised valley network present in the Bell Creek Field.

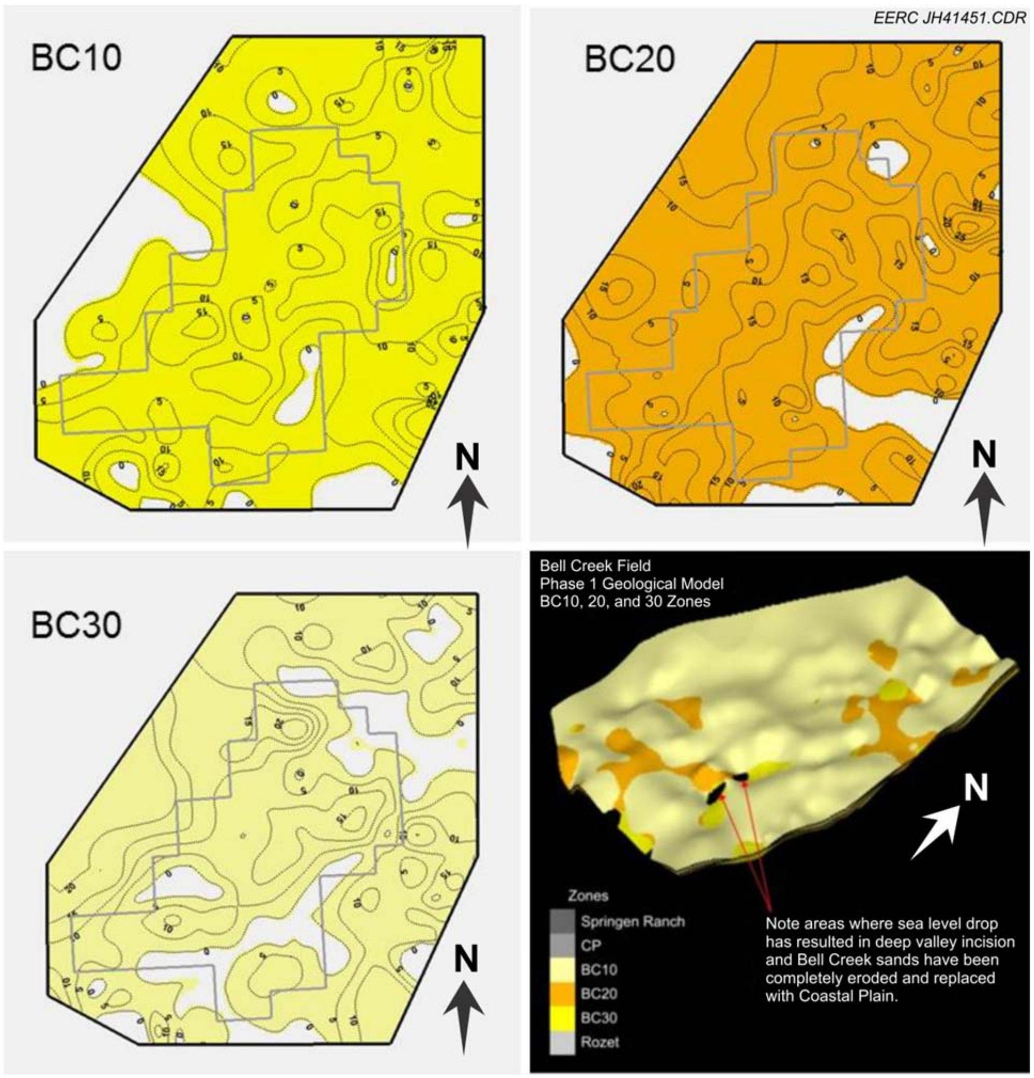


Figure 7. Map views of BC10, BC20, and BC30 zones with labeled thickness contours. Phase 1 development area outline is in gray.

Structural and Property Model

Grid thickness was assigned to each zone to refine reservoir properties and model resolution. In total, 34 layers were assigned to the structural model within the six zones (Table 1) based on optimal grid size analysis which resulted in cell sizes of 100' × 100' and maximum thicknesses of 3–5 ft. The model contains a total of 1,462,884 grid cells with 202, 213, and 34 cells in the i, j, and k directions respectively.

The structural model was then populated with petrophysical properties obtained through data reconnaissance. These properties include total porosity, shale volume, effective porosity, net-to-gross ratio, permeability, water saturation, formation pressure, and formation temperature. The distributions of these properties within the 3-D geologic model are provided in Appendix B.

RESERVOIR SIMULATION

While the geologic model provides a framework for planned simulation activities, reservoir simulation incorporates a variety of additional reservoir data to accurately simulate the reservoir's pressure and fluid mobilization response to injection or production processes. Much of the geologic and structural reservoir properties will be directly incorporated through the integration of the 3-D geologic model; however, additional PVT data, relative permeability data (obtained through special core analysis), and well production history are also imperative to simulation activities.

Reservoir Fluids and PVT

Injection processes are most effective to enhance recovery when the injected gas is nearly or completely miscible with the oil in the reservoir. It is known that the behavior of gas miscibility is highly pressure dependent and is expressed as MMP (minimum miscibility pressure) which defines whether the displacement mechanism is miscible or immiscible. By determining MMP in context with the study area, miscibility between Bell Creek crude oil and injected CO_2 can be better understood.

Compositional analyses of Bell Creek crude oil from Wells 2608 and 0511 show that the reservoir produces sweet, black crude oil with a mole fraction of liquid hydrocarbons (C_{7+}) for

Table 1. Model Layering of Geological Model

			Cell Thickness, ft	
Zone	Layers	Layer Number	Range	Average
Springen Ranch	3	1–3	4.33	4.33
Coastal Plain	5	4–8	0–4.5	0.94
BC10	8	9–16	0–3.0	1.03
BC20	8	17–24	0–3.4	1.08
BC30	7	25–31	0–3.1	1.05
Rozet	3	32–34	5	5.00

all samples greater than 25%. Results show that the crude oil samples from Wells 2608 and 0511 are of similar composition. The oil compositions were utilized in conjunction with appropriate reservoir conditions in order to predict MMP.

Reservoir fluid reactions to PVT (pressure, volume, and temperature) data are an integral part of reservoir simulation, as they are necessary to accurately define fluid properties and behaviors at varying reservoir conditions. PVT data for three Bell Creek crude oil samples from Wells 2605, 2608, and 0511 are available and were used to define PVT relationships under reservoir conditions (Figure 8). Constant composition expansion (CCE), differential liberation (DL) analysis, separator, swelling test and fluid compositional analysis data were also available for oil samples from these three wells (C_1 through C_{11+} for Well 2605 and C_1 through C_{36+} for Wells 0511 and 2608).

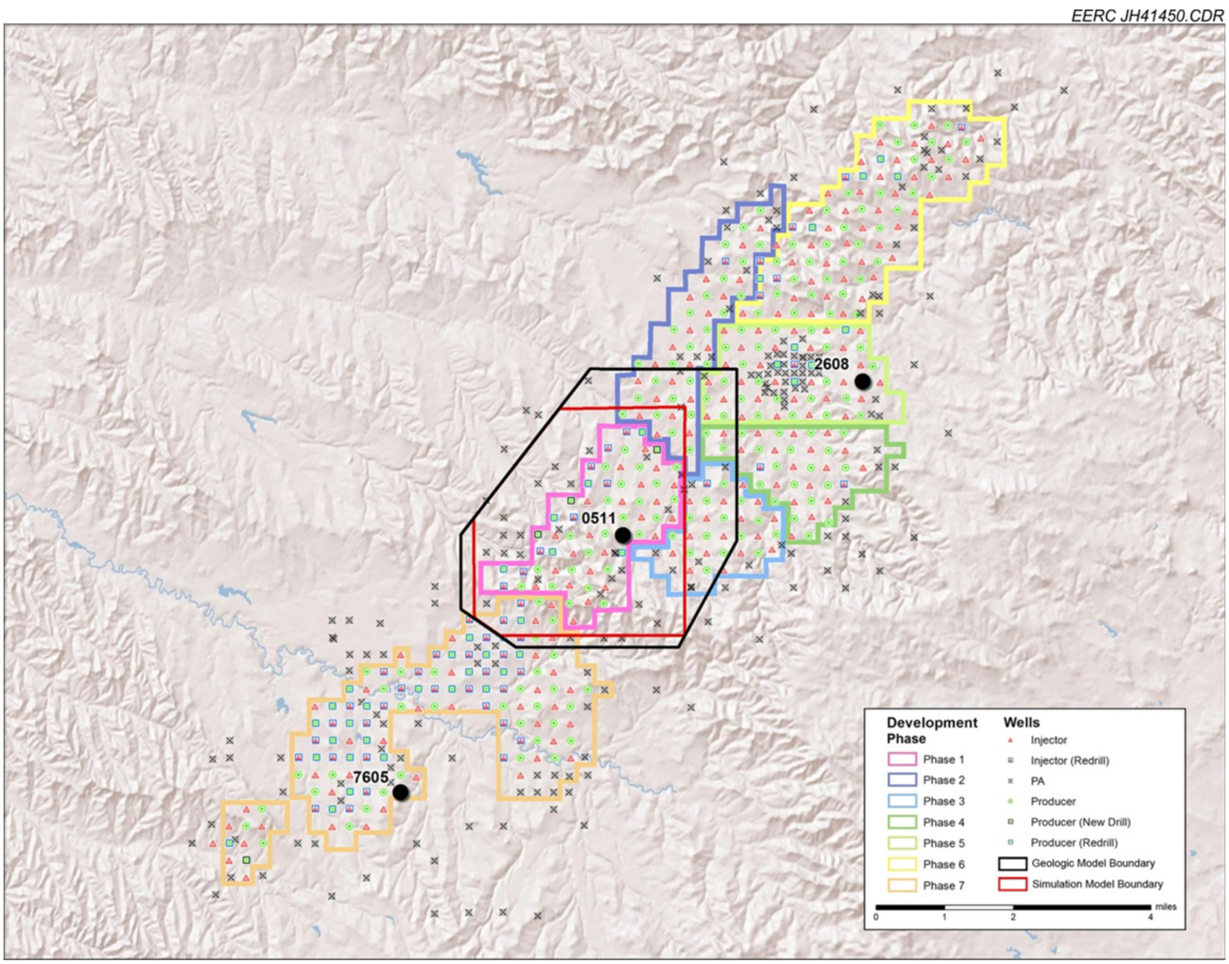


Figure 8. Map of the Bell Creek oil field showing development phases and the three wells with available PVT analysis within the Bell Creek Field.

Minimum Miscibility Pressure

Injected CO_2 interacts with reservoir fluids in either a miscible or an immiscible process. The fashion and efficiency of this system is highly dependent on reservoir conditions (pressure and temperature) but also is a function of gas and oil composition. For instance, high-molecular-weight oil and oils already containing dissolved gas such as methane and nitrogen tend to have higher MMPs.

An equation of state (EOS) was utilized to model the fluid properties of the Bell Creek reservoir to improve fluid property predictions over conventional generic black oil models. Computer Modeling Group's (CMG's) WinProp, a PVT analysis application, uses cubic EOS to perform phase equilibrium and property calculations. Simulations of PVT experiments on the three available samples were conducted and, because of the tight range of resulting data, only the results from Well 0511 are discussed, as the data set and location of this well is most applicable to the model area. PVT data from Well 0511 were tested in regard to simulated results of DL, CCE, and swelling tests and showed less than a 2% variance between experimental data and calculated results of EOS after tuning. Comparative results between the EOR tuned simulation results and the PVT experimental data for C_1 through C_{6+} are presented in Appendix A. Table 2 provides a comparison of experimental values of MMP and calculated simulation results.

On the basis of collected experimental data, the solution gas-to-oil ratio (GOR, expressed in standard cubic feet [scf] per stock tank barrel of oil [STB]) as a function of pressure was determined from the DL experiment, as shown in Table 3. After the regression of PVT tests, the predicted CO_2 MMP for oil with a GOR of 227.80 scf/STB is 2875 psia. It should be noted, however, that the PVT tests for oil samples with GORs other than 227.80 scf/STB were not performed. With the exception of a MMP prediction of 2875 psia, the other MMP predictions

Table 2. Comparison of Experimental MMP Values and Calculated Simulation Results

	Oil from Well 0511		
Experimental	3181		
	C_{6+} Fraction	C_{36+} Fraction	Component Lumping
Calculated	2825	2750	2725

Table 3. MMP for Reservoir Fluid and Stock Tank Oil (Well 2608)

Bubble point Pressure, psia	GOR, scf/STB	MMP, psia
1208	227.80	2875
915	175.64	2665
615	126.71	2470
215	54.32	2140
15	0	1915

were made without regression of PVT tests. It has been shown that GOR has a strong impact on MMP, where higher light fractions raise miscibility pressures and low gas contents lower miscibility pressures.

Light fractions in Bell Creek crude oil consist primarily of methane (C_1). The mole fractions of the C_1 component were varied to have different GORs in the reservoir fluid, and then a simulation was run to predict the MMP (Table 3). The predicted value for MMP dropped 33%, from 2875 psia for Bell Creek reservoir oil to 1915 psia for the stock tank oil, which is considered to be completely degassed (Figure 9). CO_2 MMP for the reservoir fluid as the solution gas is released decreases monotonically with the GOR of the oil, assuming the primary gas contribution is C_1. The results show that the effect of GOR (solution gas) present in the oil can be significant.

While GOR and the required reservoir pressure are complicated in terms of reservoir heterogeneity and past and future management, this value should be a target to reach, exceed, and maintain to maximize production. In the event that compartmentalized blocks have been shown to produce low gas or dead oil, miscibility may be significantly lower, as predicted above, and may be reasonably managed as such if lower pressures are determined to be practical.

FUTURE WORK

Prior to the start of injection, the current geologic model will be updated with seismic data, petrophysical well log interpretation, and core analysis data, which will be acquired during the

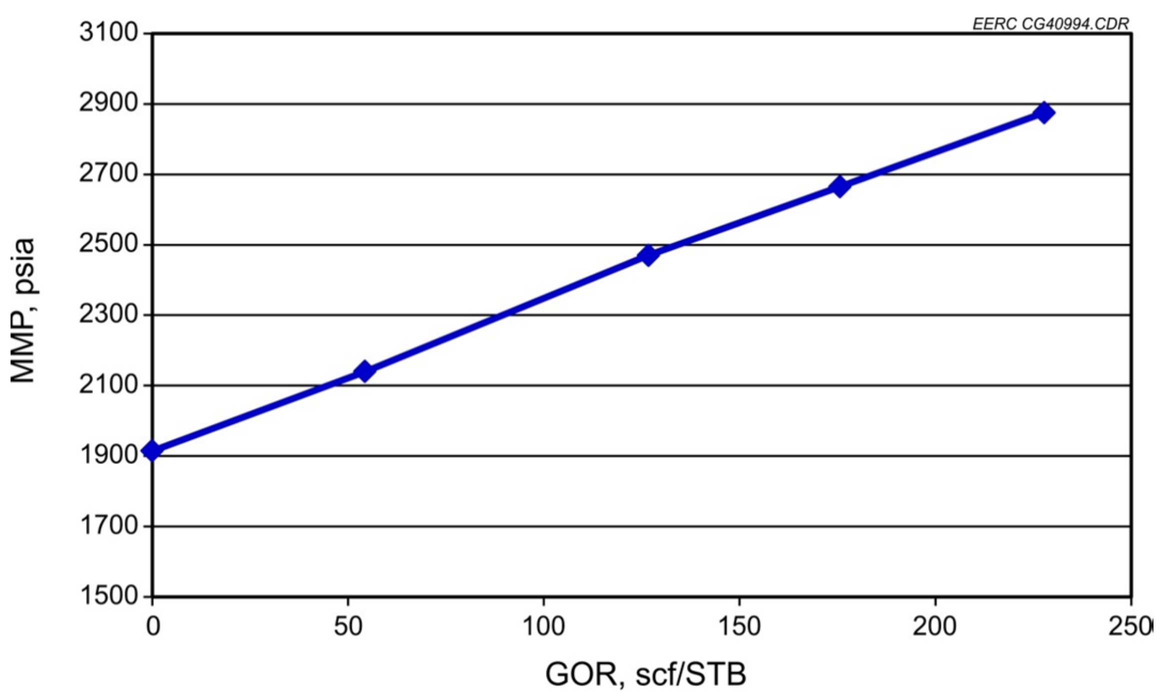


Figure 9. Graph illustrating the calculated effects on MMP as the GOR is increased.

installation of a monitoring well in the Phase 1 development area during the winter of 2011. The data will be analyzed and interpreted for petrophysical properties, structure, fluid saturation, chemical analysis, relative permeability, and rock mechanics for both the reservoir and sealing formations. These additional data will help to better understand the pay zones, reservoir seals, and remaining oil saturation in the model area. Once the new data have been integrated into an updated geological model, a 3-D compositional reservoir simulation model will be built.

In addition to the new information gathered from the monitoring well, which will be vital for reducing uncertainties in the injection simulation results, the monitoring well will also allow for the implementation of a broad array of monitoring techniques and technologies. These technologies will provide data points to check the validity of the simulation results and provide updated time-lapse data which can be used to update simulation parameters, thereby assuring agreement between predictions and the physical reservoir response.

Fluid flow simulation will be performed on the simulation model using GEM, a 3-D compositional reservoir simulator developed by CMG. The flow simulation studies will allow for validation of the geologic model and the fine tuning of model parameters to match physical reservoir conditions through production and injection history matching. The history match on the geologic model will be performed utilizing production and injection rates, water cut, and pressure data from the field spanning the years 1967 to 2010. History matching will reduce the geologic uncertainties, which will allow for more accurate prediction of future reservoir performance during and after injection.

In conjunction with history matching, a sensitivity analysis will be utilized to identify parameters having the greatest effect on simulation results. These key parameters can be targeted for fine-tuning, thereby greatly reducing the time and resources required for the history-matching process. The identified key parameters can be targets for enhanced evaluation during the drilling and completion of the monitoring well to further minimize uncertainties in the model.

Once a good history match is achieved, it will be used as the baseline for evaluation of CO_2 EOR development schemes, improved understanding of CO_2 migration through the reservoir, analysis of project risk, and prediction of the long-term fate of injected CO_2. These simulations will in turn aid in the guidance of monitoring activities to assure that data acquisition occurs at optimal points and/or optimal locations during and after injection to maximize the utility of the data acquired.

Multiple simulations and resulting realizations will be required to evaluate reservoir behavior during injection and to predict CO_2 migration pathways in the subsurface. These realizations will be analyzed in terms of probability to produce estimates of CO_2 migration vectors and saturations. Results will be ranked in terms of likelihood that a particular CO_2 saturation will be experienced at a given distance and direction from an individual injection wellbore. Various injection strategies such as CO_2 injection and CO_2–WAG (water alternating gas) will be evaluated to determine oil recovery efficiencies and CO_2 storage efficiencies under various injection schemes. Other injection parameters that may be evaluated in terms of the combined CO_2 EOR and storage process include injection rate, optimum total slug, optimum slug size per WAG cycle, and optimum WAG ratio.

To assess the potential for CO_2 leakage during and after injection, a 3-D geomechanical model will be constructed to predict the potential for fault reactivations and fracturing caused by the CO_2 injection process. Using rock mechanical properties such as in situ stress and fracture envelopes, potential CO_2 leakage paths can be anticipated and monitored. The geomechanical model will also simulate the long-term variations on the geomechanical parameters to ensure the effective injection and storage of CO_2 for the Bell Creek oil field.

SUMMARY

A 3-D static geologic model of the Bell Creek study area has been created to provide a geologic framework for future reservoir simulation activities. The Peng–Robinson equation of state was tuned to match experimental PVT tests in order to predict CO_2 MMP. A host of petrophysical well logs, core analysis, and well history data was integrated into a 3-D geological model of the Phase 1 and surrounding areas within the Bell Creek oil field to be utilized in conjunction with a planned workflow to simulate and evaluate potential injection strategies for the field.

Ongoing and future work consists of:

- Sensitivity analysis to optimize computational time and resources while maximizing accuracy of the model.
- History matching the production and injection data to validate and fine-tune the geologic model.
- Evaluating multiple likely CO_2 EOR and storage schemes.
- Predicting the migration pathway, plume size, and reservoir storage efficiency of the injected CO_2.
- Constructing a coupled geomechanical model to identify, anticipate, and evaluate the potential risk for out-of-zone fluid migration caused by reservoir integrity in order to guide the monitoring program.
- Determining the long-term fate of injected CO_2 in the simultaneous CO_2 EOR and CO_2 storage operations.

Key results of current work include:

- The calculated results of PVT tests in CMG's WinProp PVT package match the laboratory measurements with precision.
- PVT simulations indicate miscibility will be attained with CO_2 gas at approximately 2800 psia.

- Qualitative investigation of the effect of GOR on MMP indicates that GOR could significantly affect MMP.

- Construction of a 3-D static geologic model of the Bell Creek Field has resulted in new interpretations regarding the total porosity, shale volume, effective porosity, permeability, reservoir thickness, and water saturation.

- The 3-D static geologic model will be updated as data from the monitoring well become available. The current geologic model has been constructed to provide a geologic framework using the available geophysical and geological data. This geologic model will aid in the evaluation of various injection strategies and parameters for CO_2 EOR and CO_2 storage.

REFERENCES

Encore Acquisition Company, 2009, Bell Creek CO_2 project: Encore Acquisition Company internal report.

APPENDIX A

PVT REGRESSION RESULTS FOR WELL 0511

PVT REGRESSION RESULTS FOR WELL 0511

Comparison results matching equation of state (EOS) to experimentally measured pressure, volume, temperature (PVT) data are presented. The experimental data and two lines of simulated data are shown on each figure. The first simulated line (Init.) represents the EOS prediction with the preregressed parameters. The second line (Final) represents the EOS prediction with regressed parameters.

Figure A1 shows the results of the detection limit (DL) test for the oil sample from Well 0511. After tuning both gas–oil ratio (GOR) and relative oil volume (ROV) agree extremely well with experimental data (Figure A1a). As shown in Figures A1b and A1c, the gas compressibility (z), gas formation volume factor (FVF), and gas and oil storage gas (SG) are in excellent agreement with experimental measurements. Figure A1d indicates agreements were obtained for both oil viscosity and gas viscosity.

The results of the constant composition expansion (CCE) test are shown in Figure A2. A match was obtained for relative volume (Figure A2a) and oil compressibility (z) (Figure A2b). Figure A2c shows that, after EOS tuning, the calculated results of oil density match well with the experimental data.

The results of the swelling test are shown in Figure A3. After EOS tuning, the calculated saturation pressures and swelling factors agree with the experimental data.

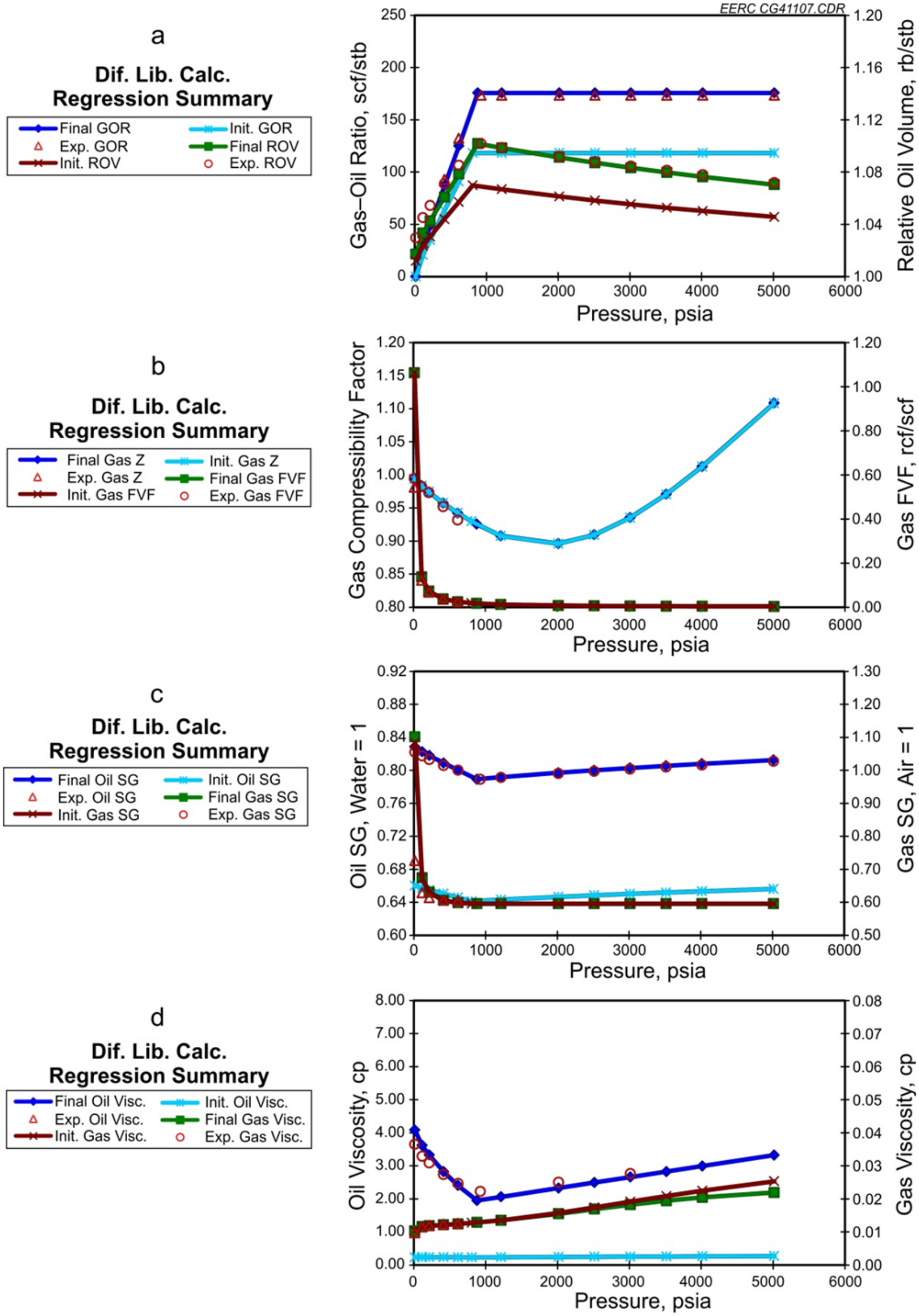


Figure A1a) Regression results of GOR and ROV for the DL East (C_{6+}, Well 0511), b) regression results of gas Z and FVF for the DL test ($C_{6+,}$ Well 0511), c) regression results of oil and gas SG for the DL test ($C_{6+,}$ Well 0511), and d) regression results of the oil and gas viscosity for the DL test (C_{6+}, Well 0511).

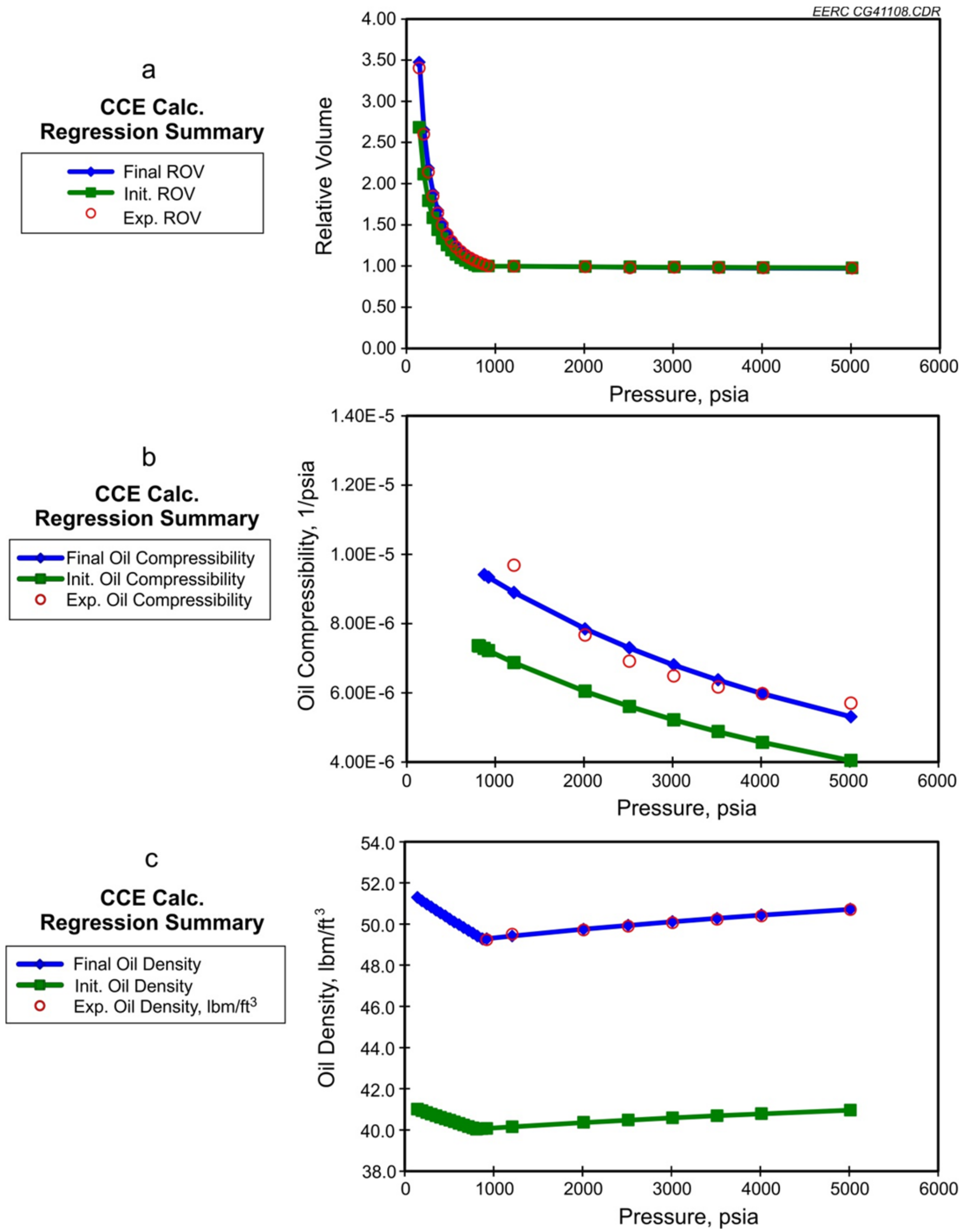


Figure A2a) Regression results of ROV for the CCE test (C_{6+}, Well 0511), b) regression results of oil compressibility for the CCE test (C_{6+}, Well 0511), and c) regression results of oil density for the CCE test (C_{6+}, Well 0511).

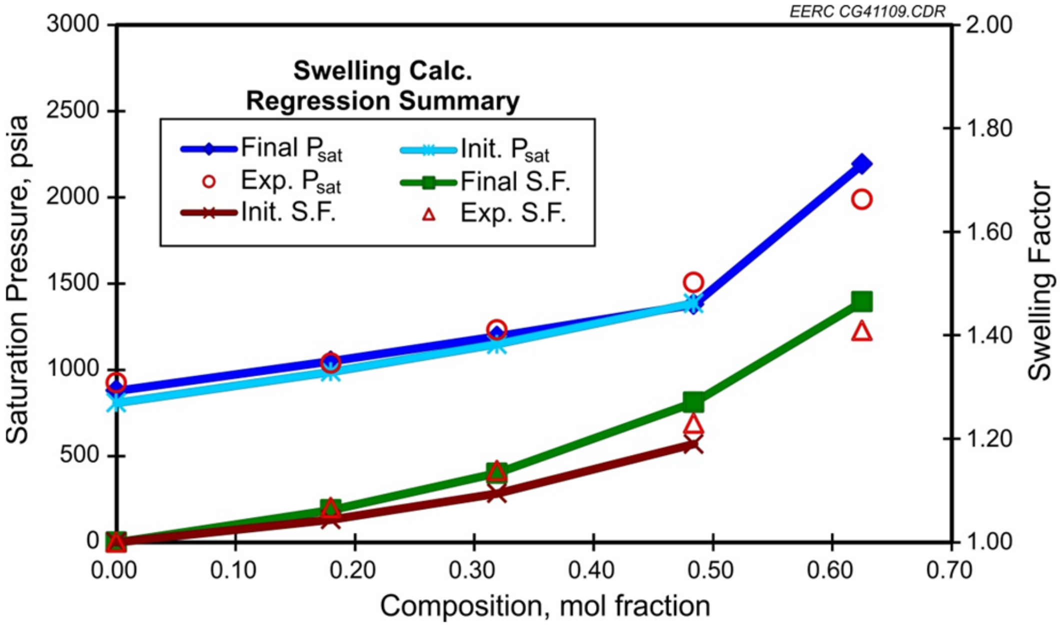


Figure A3. Saturation pressure (P_{sat}) and swelling factor (S.F.) comparison (C_{6+}, Well 0511).

APPENDIX B

3-D GEOLOGICAL MODELING

3-D GEOLOGICAL MODELING

A 3-D geological model was developed to define the spatial extent of the sands and the spatial distributions of reservoir rock and fluid properties.

3-D Grid

Figure B1 shows the geographic locations of three horizontal and two vertical cross sections within the model area (cross-sectional lines are plotted in black). Cross Section Lines A–A′, B–B′, C–C′, and F–F′ trend west to east across the project area, and Lines D–D′, E–E′, and G–G′ trend north to south. These sections were constructed on the basis of the geologic map and well data.

Population of the Grid with Petrophysical Properties

VSH expressed as a decimal fraction or percentage: Figure B2 shows the volume of shale for the coastal plain (CP) and Bell Creek (BC) zones. The shale volume (VSH) map demonstrates a high abundance of shale in the CP sequence with smaller isolated shale bodies in the BC sands. The cross-sectional view of VSH for Cross Section G–G′ is shown in Figure B3.

Porosity and permeability (low, mid-, high case): Figure B4 shows the distributions of porosity for the CP and BC zones. The cross-sectional view of porosity for Cross Section G-G′ is shown in Figure B5.

The distribution of permeability for the CP and BC zones is shown in Figure B6. The cross-sectional view of permeability for Cross Section G-G′ is shown in Figure B7.

Water saturation (S_w) (low, mid-, high case): The distribution of S_w and the depth of oil–water contact (OWC) are illustrated in Figure B8. The OWC for low, mid-, and high cases is –830, –835, and –840 ft, respectively. The cross-sectional view of permeability for Cross Section G–G′ is shown in Figure B9.

Net-to-gross ratio (NTG): Figure B10 shows the midcase NTG distribution map for CP and BC zones. The cross-sectional view of NTG for Cross Section G–G′ is shown in Figure B11.

Formation pressure: Drill stem test (DST) data were utilized to construct a formation pressure gradient map for the Muddy sandstone. Formation pressure in the geological model for the CP, BC10, BC20, and BC30 zones was assigned as the product of a cell's measured depth and the pressure gradient, while the formation pressure for the Springen Ranch and the Rozet zones is equal to the cell's measured depth times 0.433 psi/ft (normal pressure gradient). Figure B12 shows the formation pressure distribution in the 3-D model.

Formation temperature: A formation temperature gradient map for the Phase 1 project area was constructed using DST data from a number of wells in the project area. The formation temperature in the geological model is the cell's measured depth times the temperature gradient. The formation temperature distribution in 3-D model is shown in Figure B13.

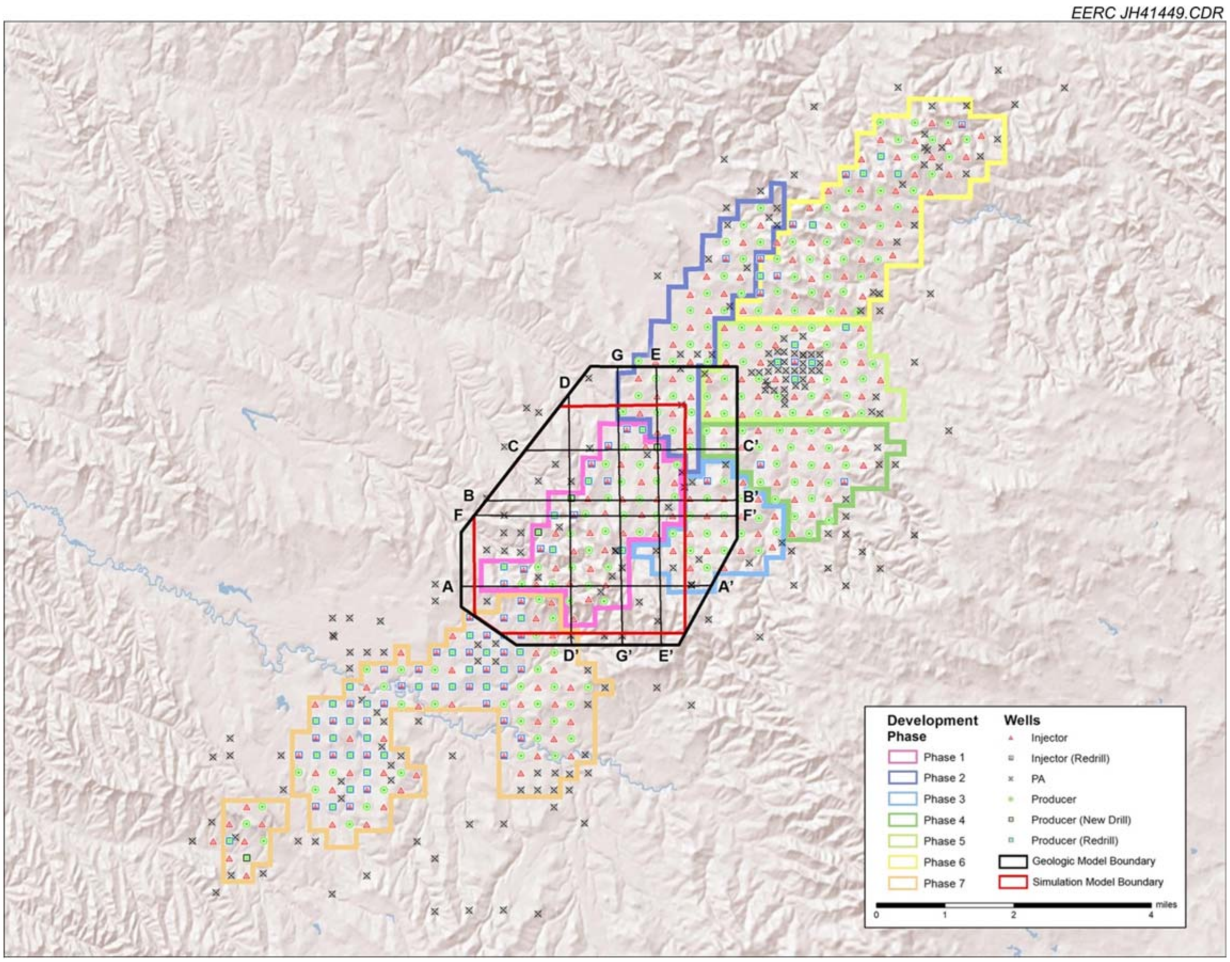


Figure B1. Locations of cross sections generated for model reporting (PA means plugged and abandoned).

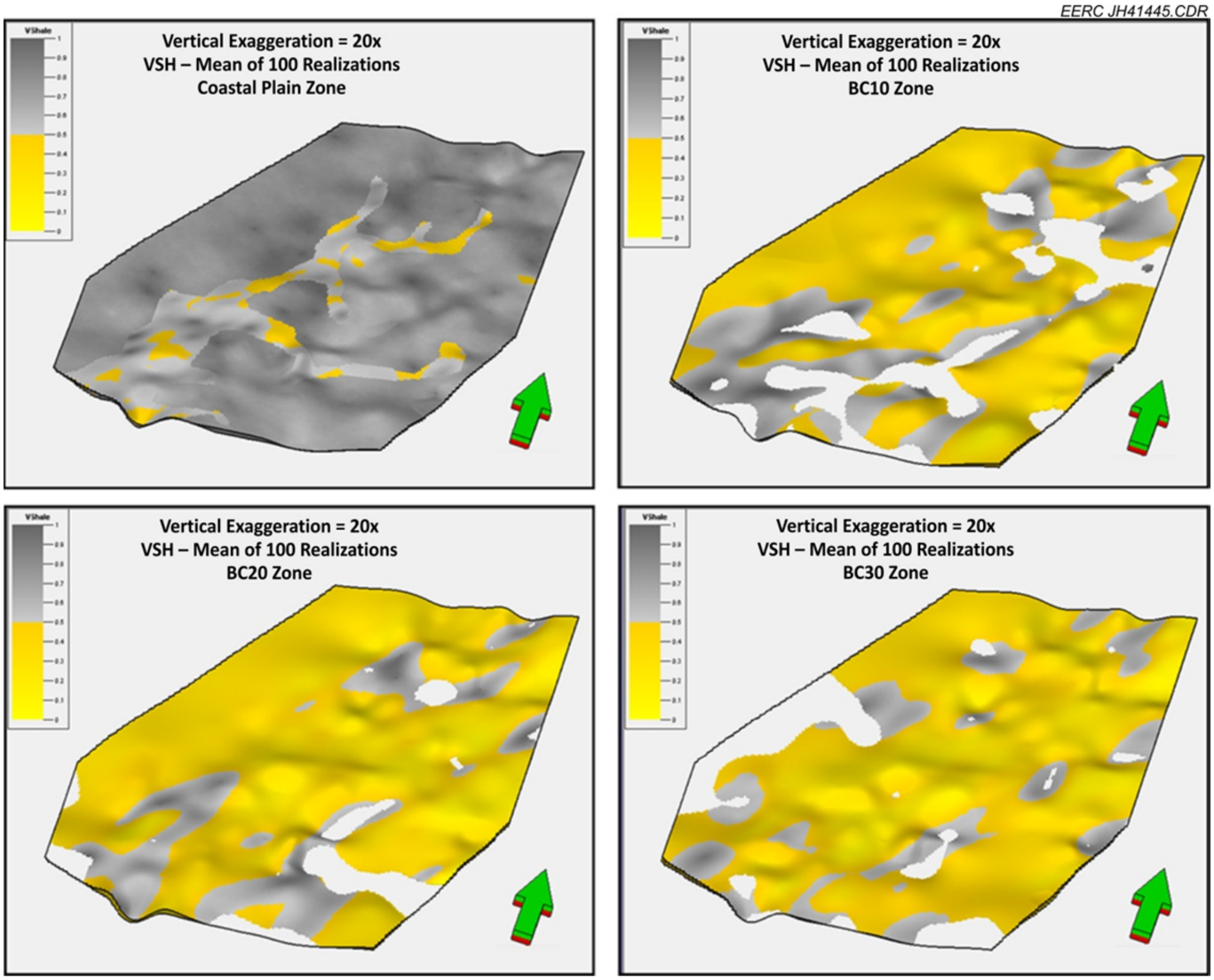


Figure B2. VSH of CP and BC zones.

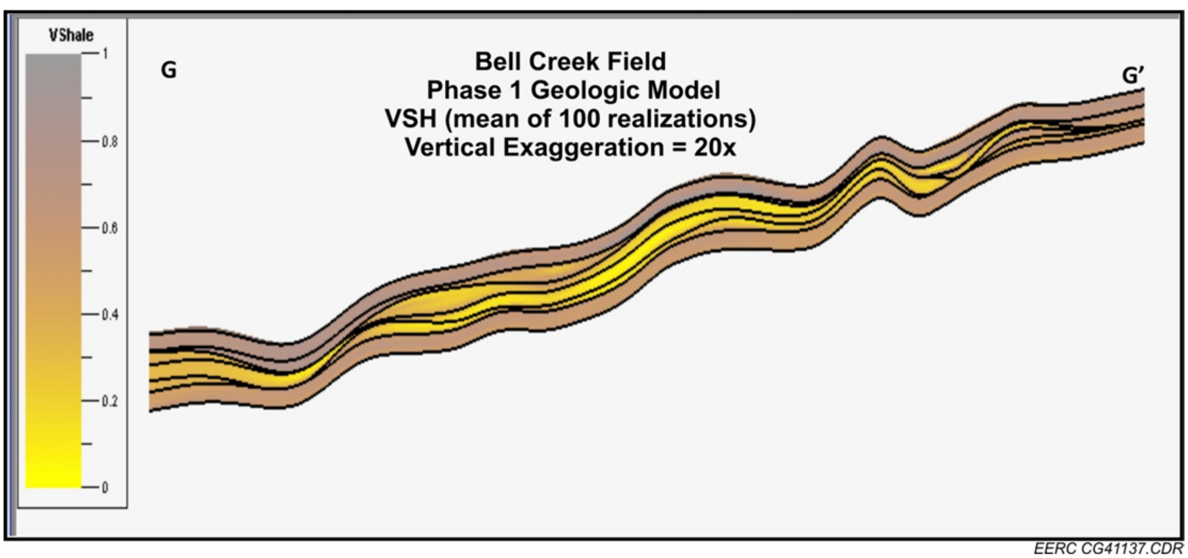


Figure B3. VSH along Cross Section G–G'.

EERC JH41444.CDR

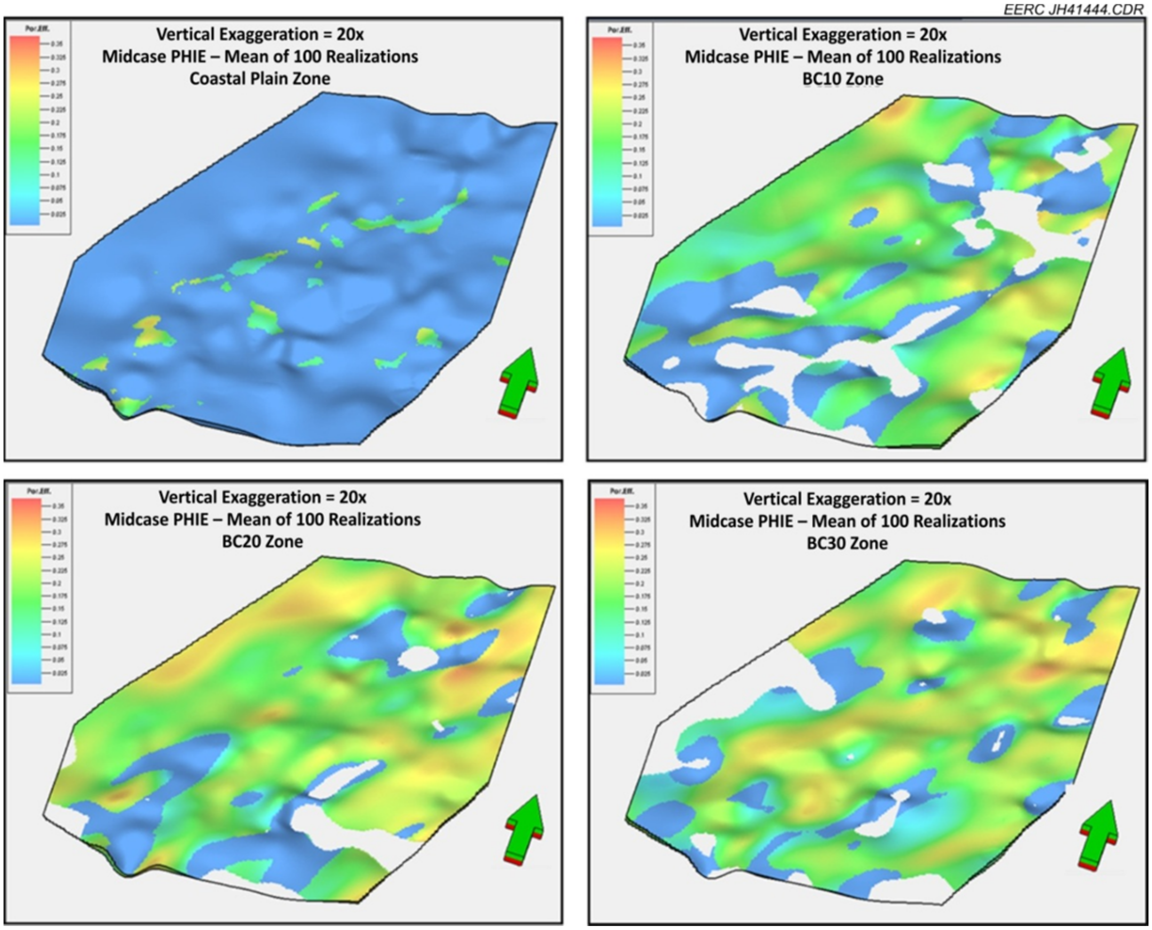
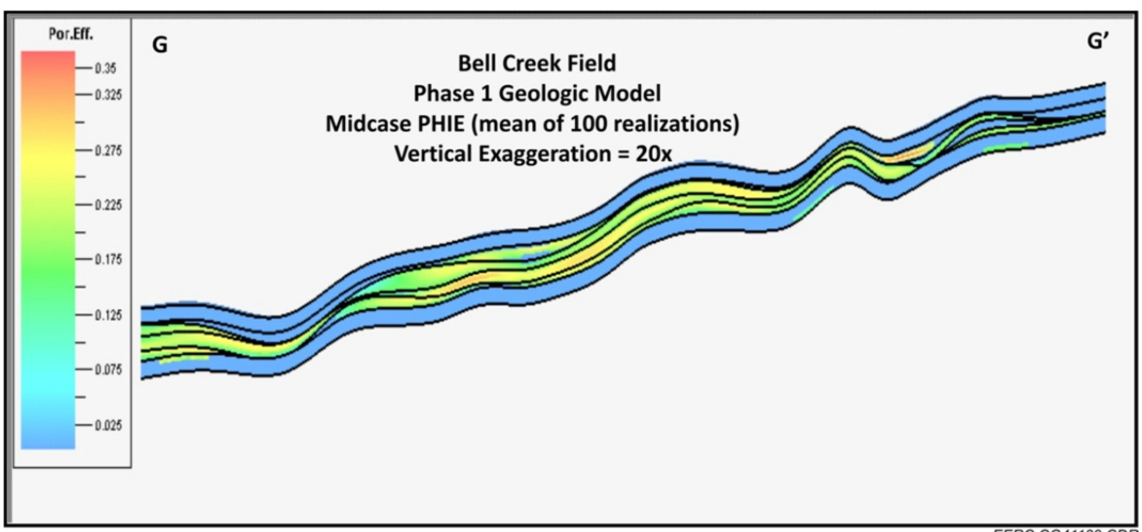


Figure B4. Porosity of CP and BC zones (midcase).



EERC CG41139.CDR

Figure B5. Distribution of porosity along Cross Section G–G'.

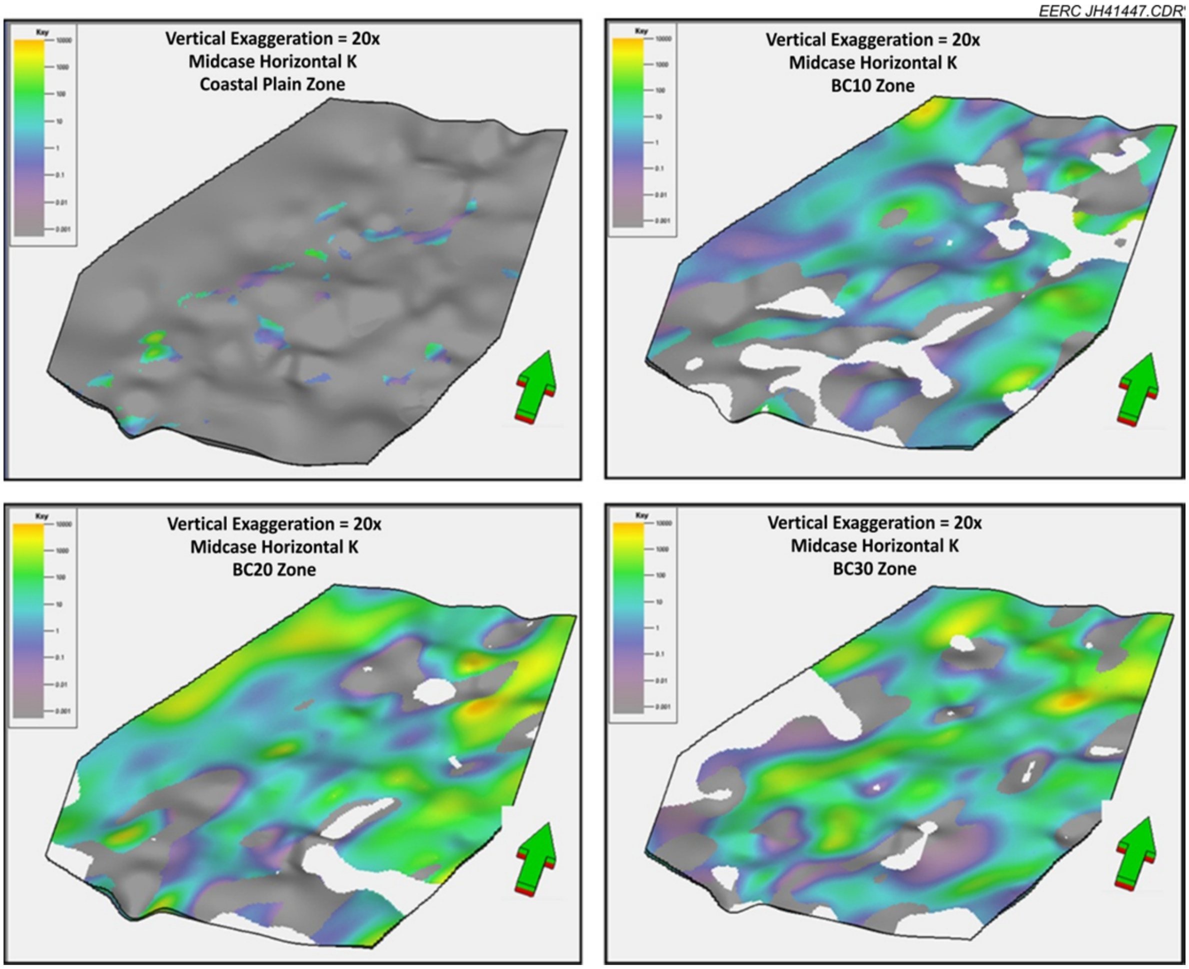


Figure B6. Permeability of CP and BC zones (midcase).

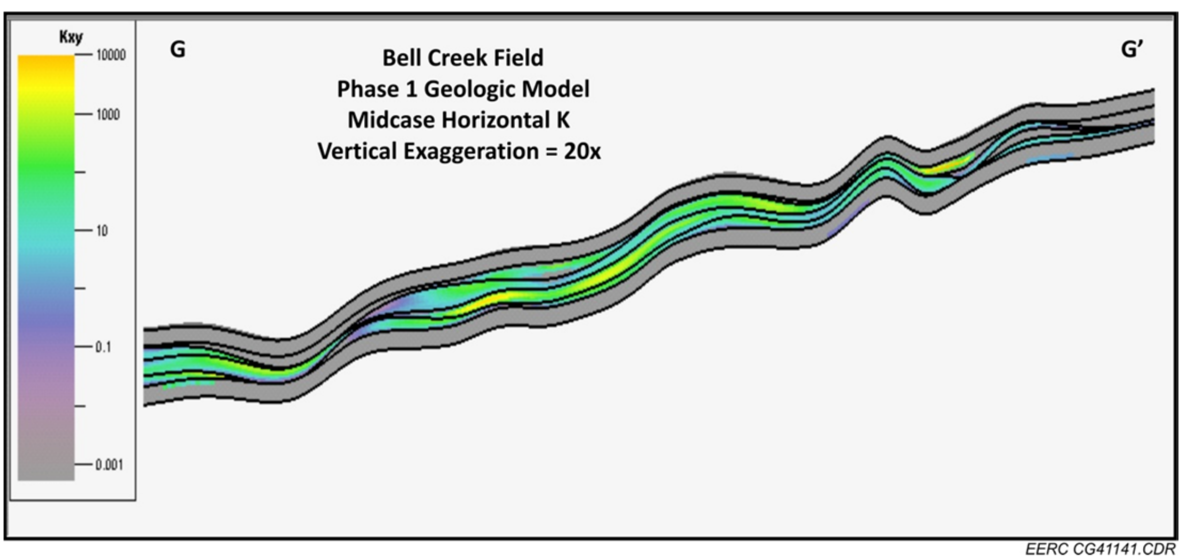


Figure B7. Distribution of permeability along Cross Section G–G'.

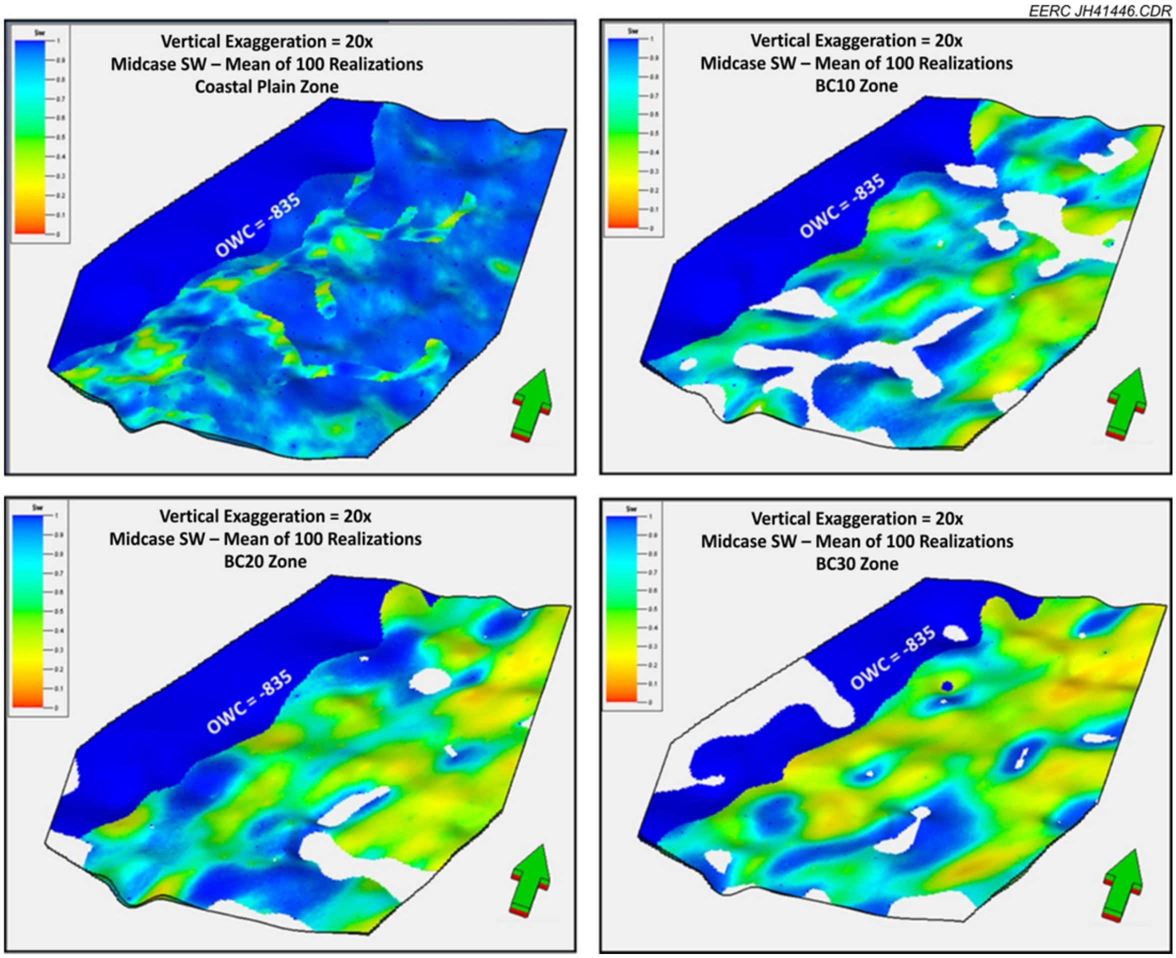


Figure B8. Water saturation of CP and BC zones (midcase).

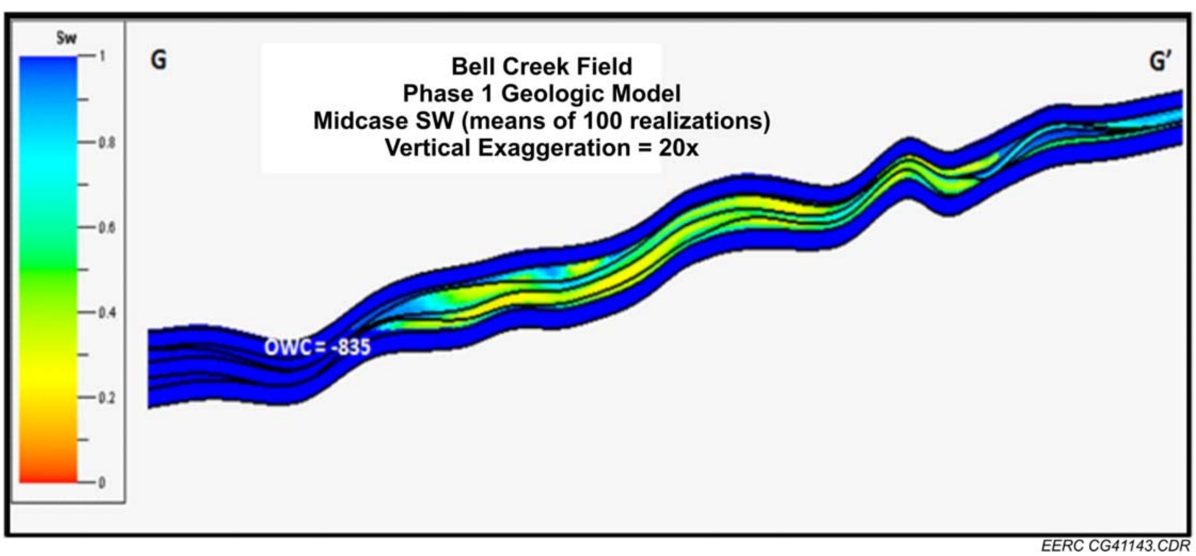


Figure B9. Distribution of water saturation along Cross Section G–G'.

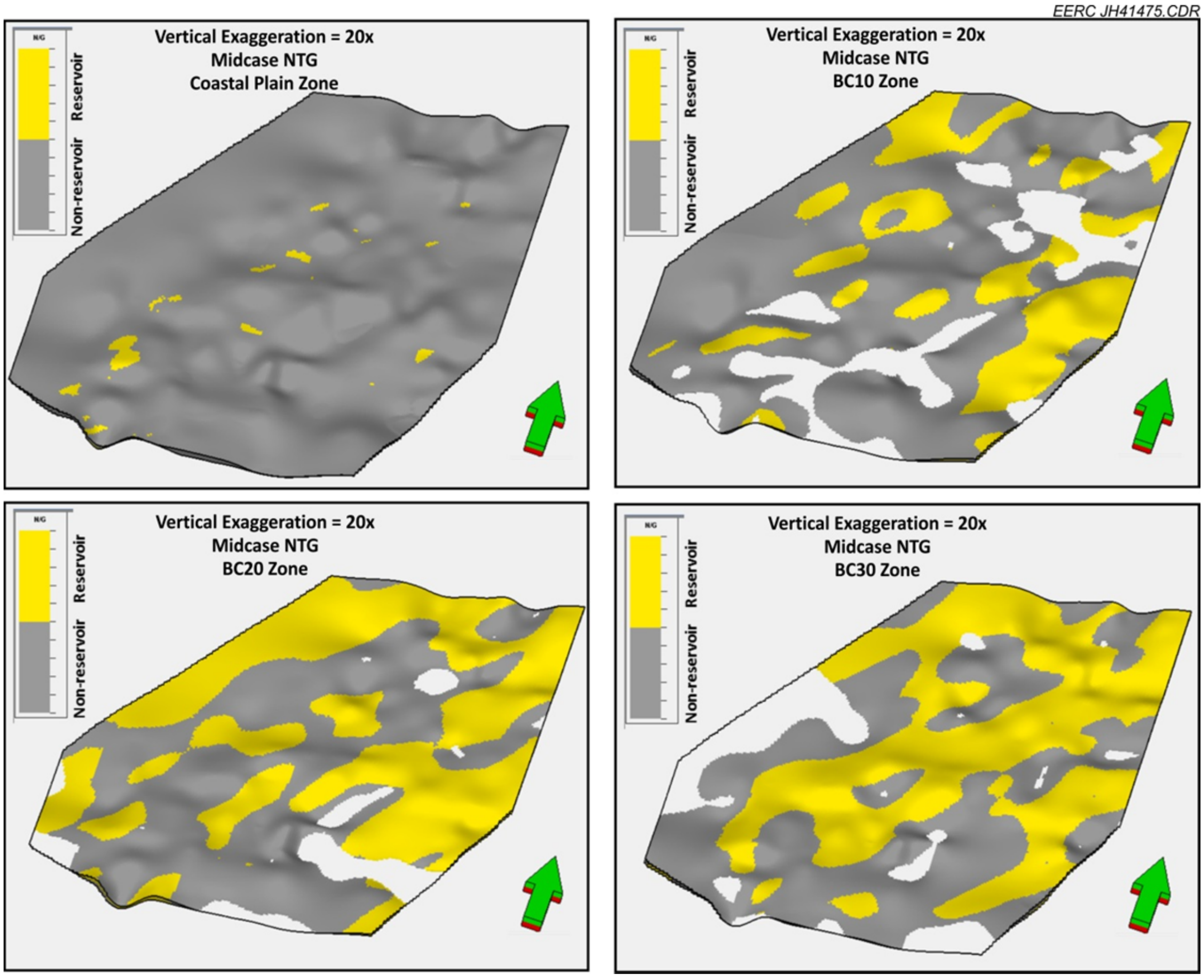


Figure B10. NTG of CP and BC zones (midcase).

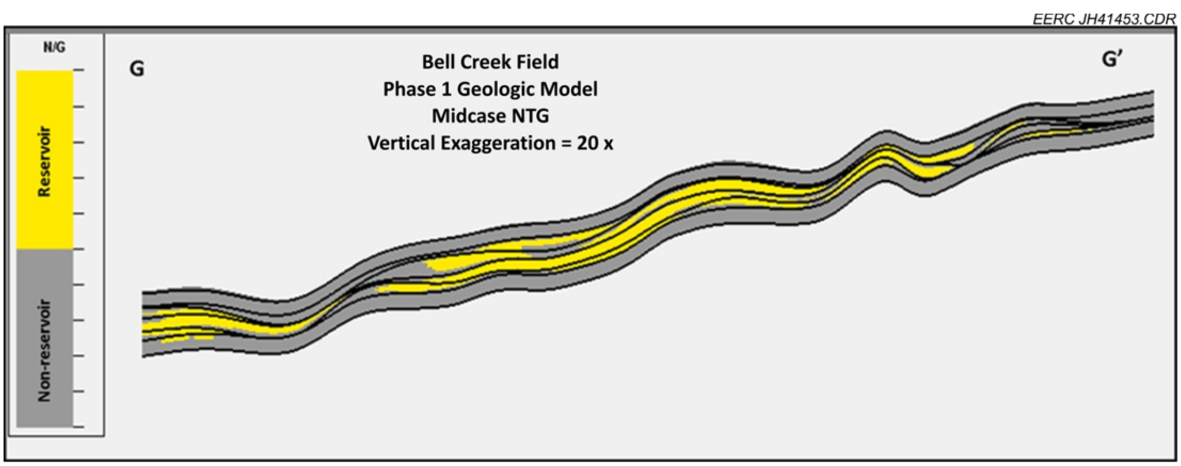


Figure B11. Distribution of NTG along Cross Section G–G'.

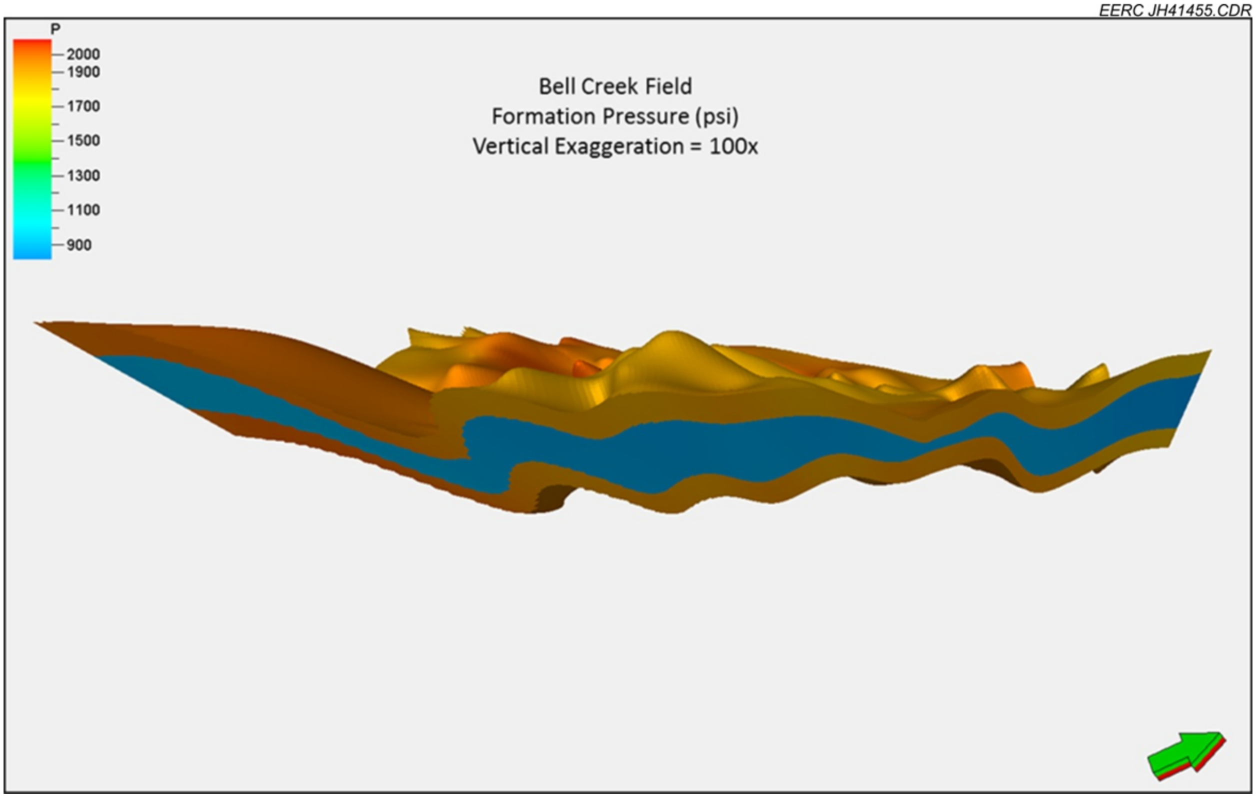


Figure B12. Formation pressure of geological model.

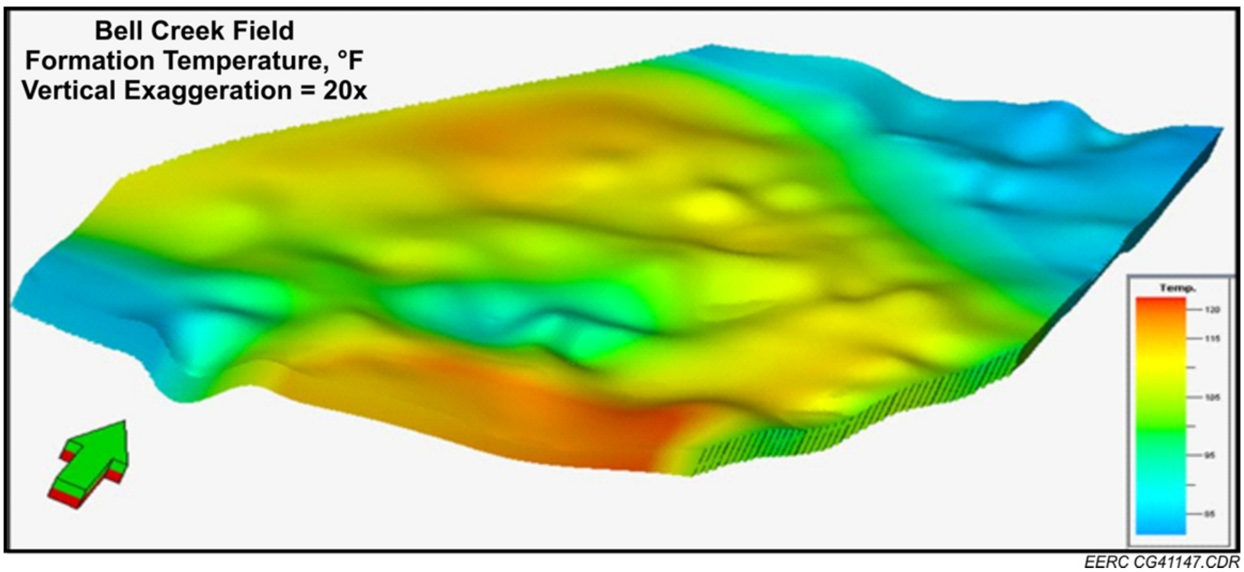


Figure B13. Formation temperature of geological model.