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SIMULATION STUDY OF SMOKY CREEK & CHEYENNE WELLS FIELDS, CHEYENNE COUNTY, COLORADO

by

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Executive Summary

3D attribute analyses revealed the presence of reservoir compartmentalization in Smoky Creek and Cheyenne Wells fields, Cheyenne County, Colorado. Reservoir simulation studies were carried out over areas of the Smoky Creek field to confirm that well production and pressure performance can be matched by assuming that the modeled wells drained from compartments with no-flow boundaries as delineated from the 3D attribute analysis. For most of the wells in the study area, simulation results closely matched the historically recorded fluid production and limited pressure data. The simulation results were used to estimate the residual reserves in Smoky Creek field and to predict the productive potential of a proposed infill well suggested by Mull Drilling Co. (MDC) - the operator. Limited production potential from the proposed infill location resulted in the abandonment of drilling plans.

Well-level production and initial saturation data were not available for many wells in the Cheyenne Wells field located adjacent and to the south of the Smoky Creek field. Thus, a multi-well simulation study could not be carried out in this field. Based on the 3D attribute map showing reservoir compartments, MDC proposed a location for an infill well named Champlin Aldrich 4 (CA 4). The CA 4 well is located in a compartment that is not drained by any other well and there are productive wells draining from other compartments in the vicinity. The uncertainties about the petrophysical properties in a yet-to-be drilled location were addressed by simulating 18 scenarios including all combinations of probable, high, and low storage with probable, high, and low flow cases. The petrophysical properties determining probable storage were estimated from analyses of wireline log data from Champlin Aldrich 3 – a neighboring well, while those determining flow were estimated from the history matching experience at the Smoky Creek wells. Results from these simulation runs were used to determine the minimum annual daily oil production rate over 10 years with 50% and 75% confidence levels. Also, the minimum net present value (NPV) calculations, given best estimate of costs with anticipated ranges of variation (from MDC), at 50% and 75% confidence levels, indicate significant positive gains over a 10-yr period. As a result of these estimates, MDC

decided to plan for drilling the CA 4 infill well to test if it drains from an isolated compartment as indicated from the 3D attribute analyses study.

Preview

Attribute analysis using 3-D survey (data) carried out over parts of the Smoky Creek field revealed possible presence of reservoir compartments. Also, based on standard well-level log analysis and 40-acre drainage, some wells showed high (> 45%) to greater than 100% recovery, thus leading to the question – are the wells draining uneven compartments? To determine if compartments as evident from the 3-D attribute analysis affected well performance, reservoir simulation of one of the larger compartments, with two productive wells, was carried out (reported in the June 2007 report). These simulation studies resulted in reasonable matches with production and pressure histories for these two wells assuming that the boundaries visible on the 3-D attribute map were no-flow boundaries.

Results of the characterization and simulation study of the Smoky Creek field were presented to the field operator, MULL Drilling Co. (MDC) – one of the industry partners in this project. Upon consultation with MDC, it was decided to history match production and pressure performances of all wells in the Smoky Creek field that had well-level production and pressure data and were located within the area surveyed with 3D, and results from this study are reported in Section 1 of this report.

Successful demonstration of our attribute analysis technique to delineate compartments in the Smoky Creek field was followed by extending the analysis to the Cheyenne Wells field located to the south and is reported in Section 2 of this report. MDC used the 3-D attribute analysis to spot an infill well (Champlin Aldrich #4) in the Cheyenne field, and planned to drill it during fall of 2008.

SECTION 1 – SMOKY CREEK FIELD

Field Background

Study Area

Figure 1 shows the structure map of Spergen over and in the vicinity of the Smoky Creek field (encircled by the blue line). For wells located within the blue line, well-level oil and water production histories (on a monthly basis) were available along with a modern suite of wireline logs. Figure 2 displays a map of positive curvature over the Smoky Creek field area thus revealing possible existence of reservoir compartments. It is the intent of this simulation study to validate if such no-flow compartments could provide sufficient reserves to history match recorded oil and gas production at the constituent wells (colored in magenta) under an active water drive that resulted in minimal loss in reservoir pressure over 30 years. It is evident from Figure 2 that the 3D seismic survey did not cover all of the Smoky Creek wells because the survey tract did not cover many of the eastern wells. Thus, our simulation study is restricted to wells (marked in magenta in Figure 2) with the following characteristics: a) located within the 3D-survey, b) have a modern suite of wireline logs, and c) have a complete well-level production history.

Log Analysis

Wireline logs were analyzed for wells in the Smoky Creek field, and cut-offs were used to determine the effective pay thickness, porosity, and water saturation (S_w). Results of this analysis are summarized in Figure 3. The cut-off parameters (porosity = 8%, S_w = 52%, V_{shale} = 0.45, and BVW = 0.049) were determined by trial and error method on the D&A (dry and abandoned) wells. Use of these cut-offs resulted in the identification of either a few feet of effect pay or none at these D&A wells. For the 7 wells (colored in magenta) that were simulated, log analyses revealed presence of effective pay in Spergen A and B in most cases, while effective pay was found in Spergen C zone in two wells.

Oil Water Contact (OWC)

Figure 4 summarizes fluid recovery data from DSTs carried out in wells in the Smoky Creek field. It was observed that water is not produced when the test interval stops at -1179 feet (subsea). However, test intervals that exceeded -1181 feet (subsea) reported presence of water in the recovered fluids. This resulted in the conclusion that the OWC is in the vicinity of -1180 feet (subsea). Figure 5A plots S_w (calculated from wireline logs) with depth for Smoky Creek wells. It shows that below -1180 feet (subsea), Sw values stabilize in the range of 0.8 to 1.0, indicating proximity to the OWC. Also Figure 5B, which plots the apparent water saturation (Rwa) calculated from wireline log analyses, shows that Rwa values stabilize around 0.1 below -1180 feet (subsea) thus indicating proximity of the OWC. It is therefore reasonable to assume that the field wide OWC is in the vicinity of -1180 feet (subsea).

Recovery Efficiencies

The majority of the wells in the Smoky Creek field are drilled on 40-acre spacing. Thus, assuming that wireline log derived storage parameters (effective pay, porosity, and Sw) being uniform within the drainage area, the recovery factor (cumulative oil production expressed as a percentage of calculated oil in place) was found to be high in some wells such as the Crosby 1 (RF = 123.6%), Crosby 3 (RF = 81.8%), Kern A4 (RF = 50.5%), and Kern 2 (RF = 61.7%) and are tabulated in Figure 6. Such high recovery factors indicate that the Smoky Creek wells were perhaps draining uneven sized compartments.

Porosity differences – log and core plug

No cores were available from the Smoky Creek field. South and adjacent to the Smoky Creek field is the Cheyenne Wells field, where two cores were available. A full suite of modern logs was run at the cored wells, namely the Klepper #4 and the Champlin Aldrich #3. Effective pay intervals were identified at these two wells using cut-off parameters established from analyzing Smoky Creek logs. At each of these two wells, wireline log-derived porosities were averaged over effective pay intervals and compared with the average porosities calculated from plug porosities taken from the same intervals. The average log-derived porosity (i.e., the average of the density and neutron porosities) differed from that measured on core plugs by ± 0.03 porosity units (i.e. log-derived porosity could be greater or less than that measured on core plugs taken from the same interval by no more that 3%).

As described later, initial porosity estimates (based on wireline log analysis) had to be increased by 0.02 to 0.03 porosity units in some of the wells in order to attain a history match. Figure 6 also lists the recovery factors calculated using porosity values necessary for history match assuming that each well drained a 40-acre area. The simulated wells are shown in magenta in Figure 6, and show high recovery factors particularly for Crosby 1 and Crosby 3 despite adjusting (increasing) their porosities from the log-derived initial value to that finally used in the simulation study to obtain history matches. This further indicates that wells in the Smoky Creek field drain uneven compartments.

Pressure Support

Initial and final shut-in pressures recorded in DSTs carried out in wells from the Smoky Creek and Cheyenne Wells fields were plotted over time in Figure 7 (A and B). Log analyses revealed that the productive intervals in Smoky Creek field consist of Spergen A, B, and C zones. In the area simulated, Spergen A is more laterally pervasive, followed by Spergen B and C. The above mentioned plots show that the reservoirs in these two fields are producing under a strong water drive that resulted in minimal decline in reservoir pressure over more than 25 years (between 1970 and 1997). Extended shut-in tests were carried out to record the static fluid columns in some of the Smoky Creek wells in the recent past, and results from these tests are plotted in Figure 7C. The above three plots indicate that the reservoir pressure has remained almost unchanged at around 1050 psi since early 1970s.

3D Compartmentalization

Cores from the Cheyenne Wells field show fractures that are mostly filled with chalcedony, megaquartz, and baroque dolomite, rather than being open, suggesting that fractures in the Smoky Creek field could serve as barriers to fluid flow, and thus compartmentalize the reservoir. 3-D seismic attribute studies in other areas have indicated that both most positive and most negative curvature can correlate strongly with fractures (e.g., Blumentritt et al., 2006). To determine if there is a relationship between either of these curvature attributes and reservoir flow barriers in the Smoky Creek field, most positive curvature and most negative curvature extracted at the approximate level of the top of Spergen have been plotted along with cumulative oil production from wells in Smoky Creek field (Figure 8). There appears to be a general correspondence between wells with lower production and strong positive curvature lineaments. Therefore, in the Smoky Creek area, positive curvature lineaments have been traced and used to define potential compartment boundaries (Figure 2).

Reservoir Simulation

A 3-layer reservoir simulation model was constructed using thickness, porosity, and S_w maps generated from data obtained by wireline log analysis. Lineaments interpreted from positive curvature map were superimposed on the structure map to indicate the location, size, and shape of each compartment. It is evident from Figure 9 shows that majority of the compartments are drained by one well except that which contains both Crosby 1 (C1) and Crosby 2 (C2). Figure 10 shows the effective pay variation in the major pay zone (Spergen A) in the Smoky Creek field. The simulator was run on an oil rate constraint, i.e., it was instructed to produce the historic monthly oil volume and in the process calculate the water production and the bottom hole pressure. In the following history matches, the historic production is plotted with symbols (green circles for oil and blue triangles for water) while the simulator-calculated rates are shown with lines (green line for oil and blue line for water). The compartment boundaries were assumed to be no-flow boundaries in this simulation study.

Crosby 1

Figure 11 shows the history match obtained at Crosby 1 well. The simulator-calculated oil volumes match the production history until 1992. Thereafter, the simulator is unable to match the historically recorded volumes. For water, the simulator-calculated production exceeds the historic volumes initially and then matches the historic records from 1981 to 1992. After 1992, the simulator is unable to match the oil production and thus operates at maximum allowable drawdown which results in very high water production.

Crosby 1 is the oldest well in the study area (started production in 1973) and has been the highest fluid producer in the study area, having produced the maximum oil and water. This well does not have a density porosity log and its porosity was estimated from a neutron porosity log. However upon comparison with other wells (Figure 3), its log-derived porosity (from neutron porosity log) is on the lower side of the average porosity (averaged from density and neutron porosity logs) range. Thus, the porosity estimated for this well (from the neutron porosity log) is less representative of the drainage area than the case when both density and neutron porosity logs are available and are averaged in the process of log analysis. The best history match was obtained when the initial (neutron) porosity was increased by 0.04 units. As mentioned earlier, an average of density and neutron porosities come close to the plug porosities, and thus neutron porosity (solely) is not representative of the porosity effective in the pay interval of Crosby 1 well.

Also, incorrect porosity estimated from neutron logs will result in incorrect effective pay and S_w estimations. Thus, effective pay thickness, porosity, and S_w values assigned to Crosby 1 are perhaps not the best estimate for the well and its drainage area. Lacking any better data, it was decided not to attempt any further improvement of the history match as it would result in adjustment some of the above mentioned parameters unnecessarily.

Crosby 2

Figure 12 displays the history match obtained for Crosby 2 well. The simulator-calculated oil and water production rates match the recorded rates for most of the well's history. Crosby 2 produces from the southern part of the same compartment that houses Crosby 1. This well has been a mid-level oil producer and a high water producer in comparison to other wells in the study area. No adjustment to log-derived porosity was required to obtain the history match.

Crosby 3

Figure 13 shows the history match obtained for Crosby 3 well. The simulator-calculated oil and water production was able to match the recorded volumes. This well has been one of the highest producers of oil with lower volumes of water in comparison to other wells in the study area. The log-derived porosity was increased by 3 porosity units to obtain the history match.

Crosby 4

Figure 14 shows the history match obtained for Crosby 4 well. The simulator-calculated oil and water production was able to match the recorded volumes. This well has been the lowest producer of oil and one of the high water producers in comparison to other wells in the study area. The log-derived porosity was increased by one porosity unit to obtain the history match.

UPRC-Hiss 1X

Figure 15 displays the history match obtained for the UPRC-Hiss 1X well located in the north-west corner of the study area. In this area, the Spergen pay dips towards the oil-water contact to the west. The simulator-calculated oil rates were unable to match the recorded oil rates after year 2000 despite increasing the log-derived porosity by 2 porosity units. It appears that as the drainage area runs out of oil, the simulator reduces the flowing bottom hole pressure to minimum set value (28 psi) which resulted in a high drawdown that led to high water production in excess to that recorded at this well. However, in the pre-2000 period, the simulator-calculated fluid volumes closely match historically recorded oil and water production. It therefore appears that the complexity of the reservoir heterogeneity prevalent in the drainage area of this well is not fully expressed in our geo-model and that attributed storage and flow properties are insufficient to history match fluid production at this well. This well also happens to be a high oil producer in comparison to other wells in the study area.

UPRC-Hiss 2

Figure 16 shows the history match obtained for UPRC-Hiss 2 well. The simulator-calculated oil and water production was able to match the recorded volumes. This well has been a moderate oil producer while producing significant volumes of water as compared to other wells in the study area. The log-derived porosity was increased by 1.5 porosity units to obtain the history match.

Kern A4

Figure 17 shows the history match obtained for Kern A4 well. The simulator-calculated oil and water production was able to match the recorded volumes. This well has been a moderate oil producer while producing the lowest volumes of water as compared to other wells in the study area. The log-derived porosity was increased by 4 porosity units to obtain the history match.

Figure 18 displays the simulator-calculated average reservoir pressure in comparison to pressures calculated from extended shut-in tests carried out at various wells within the study area. Pressures calculated from extended shut-in tests vary by ± 75 psi from the simulator-calculated average reservoir pressure. This variance is expected when an average pressure representative of the whole reservoir (and obtained from simulator output) is compared with localized extended shut-in pressures particularly in a heterogeneous reservoir where varying storage, flow, and production results in pressure variations within the reservoir.

Performance Prediction – Infill Location in UPRC Hiss 2 compartment

Based on the history matching studies, MDC evinced interest in a possible infill location in the eastern end of the compartment housing UPRC Hiss 2 well. Though the Hiss 2 well produced only 80 MBO from a 1-well compartment, it has the highest water production (not including Crosby 1 – which produced more water but over 20 additional years) amongst the study area wells. Effective pay was identified only in Spergen A zone in the Hiss 2 compartment unlike the compartment housing Crosby 1 and 2 wells where effective pay was identified in Spergen A, B, and C zones. So Hiss 2 is producing from a thinner effective pay than the Crosby 1 and 2 wells. The initial oil saturation in Hiss 2 compartment is estimated around 0.74 based on log analysis of Hiss 2 and surrounding wells.

An effective permeability ≈ 130 md was required to history-match pressure and production histories (Figure 16) at the Hiss 2 well. So it seems that the rock properties in the compartment of Hiss 2 well are such that it enabled huge water influx from the strong aquifer. To maintain reservoir pressure at 1000 psi from 1993 to 2007, fluid volumes produced out of the Hiss 2 (compartment) reservoir have to be compensated with water influx from aquifer into the compartment. If permeability around Hiss 2 were lower, then drawdown at Hiss 2 would not have been able to attract oil present in distant reaches of the compartment. Thus to meet the oil history, significant drawdown would be created in the vicinity of Hiss 2 well, which also attracted huge volumes of water from the aquifer. This resulted in high S_w and low S_o around the well, thus leading to high relative permeability to water and near zero relative permeability to oil. Under such conditions, the simulator would not be able history-match most of the later oil production history as the Hiss 2 would be watered out.

With high prevalent permeability in the Hiss 2 compartment, as has been used in the simulation model, drawdown at Hiss 2 is able to mobilize oil from distant reaches of the compartment. Thus Hiss 2 gets to drain oil from all over its compartment, in proportion to distance between the well and the drainage location, and match the 15 yr oil production history. However, any production of oil from distant reaches of the compartment is compensated for with water influx into the reservoir at that location. Thus, water saturation increases all over the compartment, but slowly, thus preventing watering out (as discussed earlier).

Figure 20 compares the initial oil saturation (of 0.74) in 1973 with that estimated from simulator results as of 2007. The oil saturation in most of the compartment (green area) is estimated to be around 0.48 as of May 2007 (from simulation output). Based on inputs from MDC, an infill well (NewHiss) was placed in this compartment (in the simulator) and produced from May 2007 to May 2012 while simultaneously shutting in the Hiss 2 well. Over the next 5 years, it is estimated from the simulation output that the NewHiss infill well would produce only 16 MBO along with 0.62 MMBW. Over this 5-

year period, the simulator-calculated production rate declined from 27 bopd to less than 5 bopd while producing about 350 bwpd (Figure 20). These production estimates from the infill well would be further reduced due to interference effects if the Hiss 2 well was simultaneously produced.

As a result of these production estimates, MDC decided not to pursue drilling an infill well in the Hiss 2 compartment.

Conclusions – Section 1

Successful history matches obtained at a majority of the wells in the study area assuming that their drainage is bounded by no-flow compartment boundaries as delineated from the 3D attribute analyses resulted in the following conclusions:

a) It is possible to history match production and available pressure histories assuming that the drainage areas of the wells are constrained by no flow boundaries of compartments that were delineated by 3D attribute analysis. [Note that simulation history matching provides non-unique solutions and thus a similar or better history match is theoretically possible using a different geo-model.]

b) Productivity estimates calculated using simulation results indicate that an infill well located in the eastern part of the compartment housing the UPRC-Hiss 2 well will be uneconomic given marginal residual oil saturation as of May 2007. These producibility estimates were used by MDC (Mull Drilling Co.) to decide against infill drilling in the Smoky Creek field.

c) Successful history matching using a compartmentalized reservoir model in the Smoky Creek field prompted Mull Drilling Co. (MDC) to request extending the 3D attribute analysis over the Cheyenne Wells field to the south to delineate reservoir compartments for site selection of an infill well.

SECTION 2 – CHEYENNE WELLS FIELD

Field Background

The Cheyenne Wells field is south and adjacent to the Smoky Creek field in Cheyenne County, Colorado. Figure 21 displays the positive curvature map based on 3D seismic data shot over the Cheyenne Wells field whose northern boundary is largely coincident with the north line of Section 33. The positive curvature map served as the basis to delineate reservoir compartments in this field. Arrows (in green) mark the locations of the Champlin Aldrich 1 (CA 1), 2 (CA 2), and 3 (CA 3) wells that surround MDC's proposed location of the infill well Champlin Aldrich 4 (CA 4) that is marked by the black arrow. Of the above mentioned three CA wells, CA 1 was drilled in 1973 and estimated to have produced around 150 MBO followed by CA 3 (drilled in 1993 and produced around 90 MBO) and lastly by CA 2 (drilled in 1974 with an estimated production less than 50 MBO), which had been beset with high water cuts since early life until being shut in. The selection criteria that MDC employed to locate CA 4 was to place it in an undrained compartment with productive wells located in neighboring compartments.

Well-level production data are not available for many wells in the Cheyenne Wells field because of commingled production practices. Also, wireline log data to calculate initial (water) saturation are not available for many wells. As a result, a robust geomodel could not be constructed for the whole field for use in reservoir simulation studies to validate the compartment (no-flow) boundaries as has been described for the Smoky Creek field in Section 1 of this report.

Reservoir Model – Champlin Aldrich 4 (CA 4) Compartment

As mentioned before, MDC's proposed CA 4 location is surrounded by 3 existing wells namely, CA 1, 2, and 3. Figure 22 shows that MDC's proposed location for an infill well CA 4 lies in a separate compartment than those housing CA 1, 2, and 3. The structure top map for the compartment containing the CA 4 well was extracted for input to the simulation software. Two scenarios were simulated, i.e., 1) a big drainage area (Ba) whose boundary is marked by unbroken red lines and 2) a medium drainage area (Ma) with a northwestern boundary marked by a broken red line while the remaining southern parts coinciding with the Ba area is marked in unbroken red lines.

Resistivity logs were available for each of the Champlin Aldrich wells. CA 1 only has a density porosity log while CA 2 only has neutron porosity log data. Comparison of plug porosity data (available at CA 3) with average porosity calculated using density and neutron porosity log shows a close match (with ± 3 porosity unit differences). However, sole use of density or neutron porosities results in significant differences with respective plug porosity values. Thus, available logs from CA 1 and 2 can not be used for a robust evaluation of effective pay at respective wells.

Figure 23 summarizes the log analysis carried out for CA 3 well. The cut off parameters and resistivity value used to identify effective pay were the same as used uniformly across the Smoky Creek wells. Identified effective pays (highlighted in yellow) mostly coincided with the perforated intervals (highlighted in pink) at CA 3. Spergen A data is shown in the left table while that on the right displays the log data from Spergen B and C, which are separated by red horizontal bands. From the log analysis, it appears that the upper most effective pay identified in Spergen A zone has not been perforated. The thicknesses and average porosity and S_w values for the respective effective pays in Spergen A and B zones at CA 3 well are also summarized in Figure 24.

Lacking a field-scale model, the compartment (shown in Figure 22) housing the location of the proposed well CA 4 was simulated. However, many uncertainties remain regarding representative values of petrophysical parameters (and their possible ranges), which are known to control storage and flow in the compartment of interest because of the absence of history matches of well performances from the Cheyenne Wells field. Uncertainties in drainage area, pay thickness, average porosity, average S_w, horizontal and vertical permeabilities, and relative permeabilities effective within the pay need to be considered for performance prediction of the proposed CA 4 well.

Figure 24 groups the major petrophysical parameters that control storage and flow in a reservoir. Figure 25 lists the assumed representative values and ranges for pertinent petrophysical parameters used in productivity prediction of CA 4 by simulation studies. Only the CA 3 well, located in the neighborhood of the proposed CA 4 well, had a complete suite of modern wireline logs, and was used to define the base (medium) case values for petrophysical parameters controlling storage at the CA 4 well. The thickness, porosity, and S_w over effective pay intervals in Spergen A (layer 1, L1) and B (layer 2, L2) and shown in blue in Figure 25 are those obtained from log analysis of data from the CA 3 well (summarized in Figure 23). The storage parameters for the high and low cases in L1 and L2 were defined from the respective high and low values observed in Smoky Creek field study.

As mentioned earlier, many wells in the Cheyenne Wells field do not have well-level production histories available. However, comparing available estimates of well-level production data from Cheyenne Wells field with that from Smoky Creek field indicates that on average Smoky Creek wells were more productive than their counterparts in the Cheyenne Wells field. Lacking any effective permeability data representative of drainage areas of Cheyenne Wells field wells, horizontal and vertical permeability data for the medium case (of the CA 4 compartment) were intentionally selected from the lower end of the permeability range of the Smoky Creek wells after completion of its history matching studies. The selected relative permeability table numbers (Figure 25) are based on data used to history match medium ($\approx$ 90MBO), high, and low producing wells in the Smoky Creek field.

Based on the 3D attribute analysis, the proposed CA 4 well may drain either a big drainage area ("Ba", as marked by unbroken red lines in Figure 22) or a medium drainage area ("Ma", marked with a broken red line to the northwest and unbroken red lines to the south in Figure 22). Thus, 9 simulation runs were carried out each for the "Ba" and "Ma" drainage areas. Each simulation input consisted of parameters that defined a combination of high (Hs), medium (Ms), and low (Ls) storage with a corresponding high (Hf), medium (Mf), or low flow (Lf) case. The names of the various simulation runs are codified using acronyms listed above and are tabulated in Figure 26.

Reservoir Simulation

In each simulation run, the proposed well CA 4 was put on line in January 2008 and was produced with a bottom hole pressure of 100 psi. The aquifer strength was adjusted such that the water production in any case did not exceed 300 bwpd after 10 years and the reservoir depletion did not exceed 100 psi from a starting pressure of 1095 psi in 2008. Figure 27 summarizes the results from the 18 different simulation runs by tabulating the daily oil production averaged from annual cumulative production. It also shows the simulator-calculated minimum and maximum oil production rates for each year from 2008 to 2018.

Uncertainty Analysis

Using the minimum and maximum annual daily production rates as the two end points of an uniform frequency distribution, a commercial risk analysis software was used to identify the minimum annual daily rate for each year that can be expected with 50% (shown in red in Figure 28) and 75% (shown in blue in Figure 28) certainty. These minimum annual rates are plotted in Figure 28 to demonstrate the expected production-rate decline at the proposed CA 4 well with 50 and 75% confidence levels. Lacking any detailed data about petrophysical properties in the study area compartment, this kind of risk analysis was found to be critical by MDC in deciding whether to drill at the proposed CA 4 well location.

Annual cumulative production from each of the 18 simulation runs is tabulated in Figure 29 along with the minimum and maximum cumulative oil production for each year, which were set as the end points of an uniform frequency distribution for each respective year. Additional cost information estimates were provided by MDC along with expected ranges to cover variations that may arise during the drilling of CA 4, and are listed in the bottom right corner table. Triangular frequency distributions were constructed for each cost factor using the most expected, high, and low values. Using these parameters, a commercial risk analysis software was used to calculate the minimum net present value (NPV) with 50 and 75% certainty. Figures 30 and 31 show that the minimum NPV over a 10 year period is estimated at $10.9 million and $8.9 million for 50 and 75% certainty levels respectively. Also, a tornado plot in Figure 30 shows that the major driver factors that determine the NPV include: a) Year 1 (oil) production volumes, b) oil price, and 3) Year 2 (oil) production volumes.

Conclusions – Section 2:

1. Reservoir compartmentalization can be delineated from 3D attribute analysis in Cheyenne Wells field.

2. The compartment selected for the proposed infill well is based on its identification as undrained compartment located in the vicinity of productive wells that drain other compartments.

3. Based on the level of resolution of the attribute maps, the selected compartment can drain from a big or a medium-sized area.

4. Most probable storage petrophysical data at the proposed CA 4 location were estimated from log analyses carried out at the Champlin Aldrich 3 well, while most probable flow petrophysical properties were estimated from data used to history match wells in Smoky Creek field. Based on these inputs, a series of simulations was carried out assuming a big and a medium-sized drainage area. Decline curves for minimum annual average oil production rate at 50 and 75% confidence levels were estimated from these simulation results.

5. NPV calculations at 50 and 75% confidence levels using operator's cost data show significant value creation over a 10-year production life for the proposed CA 4 well.

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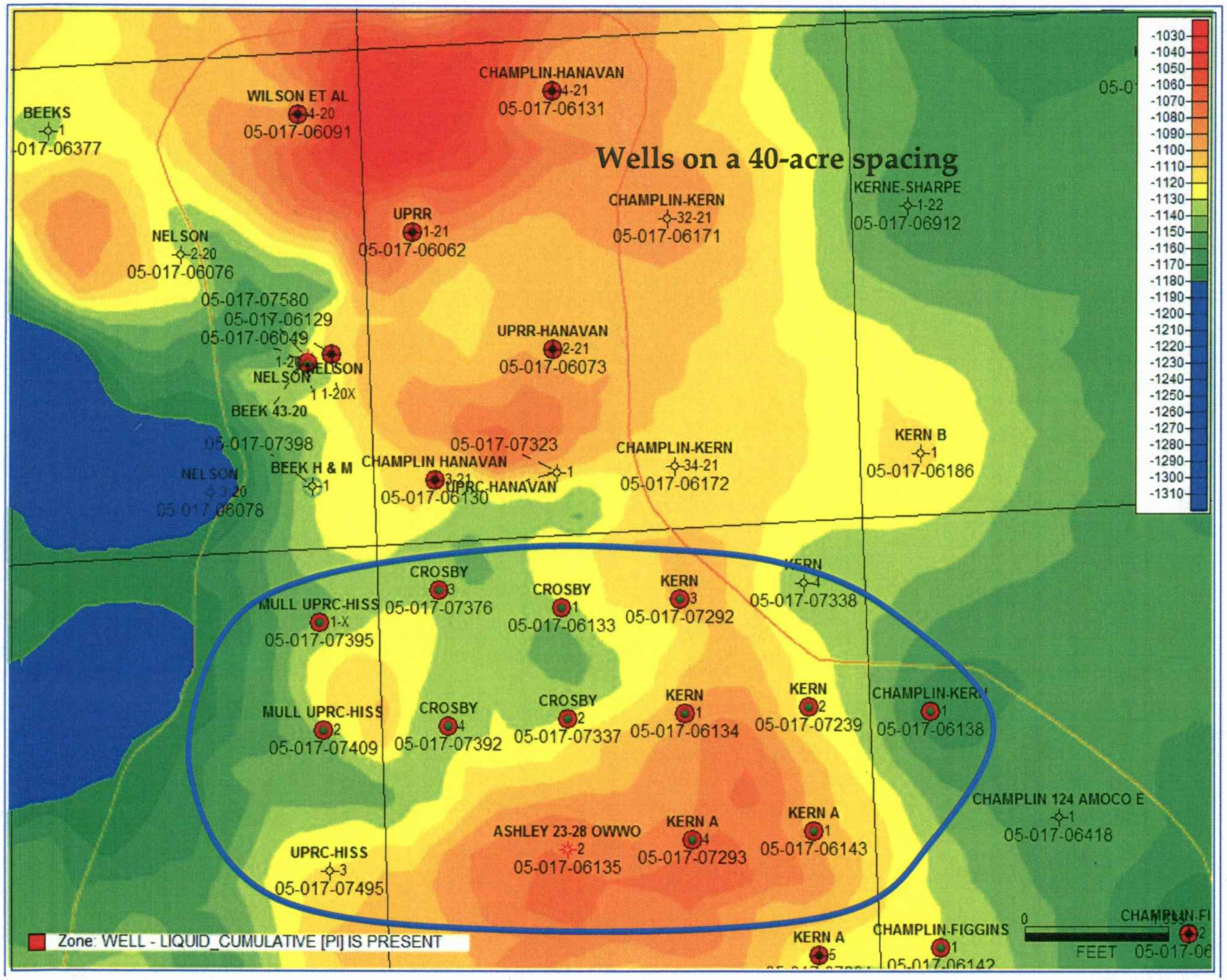
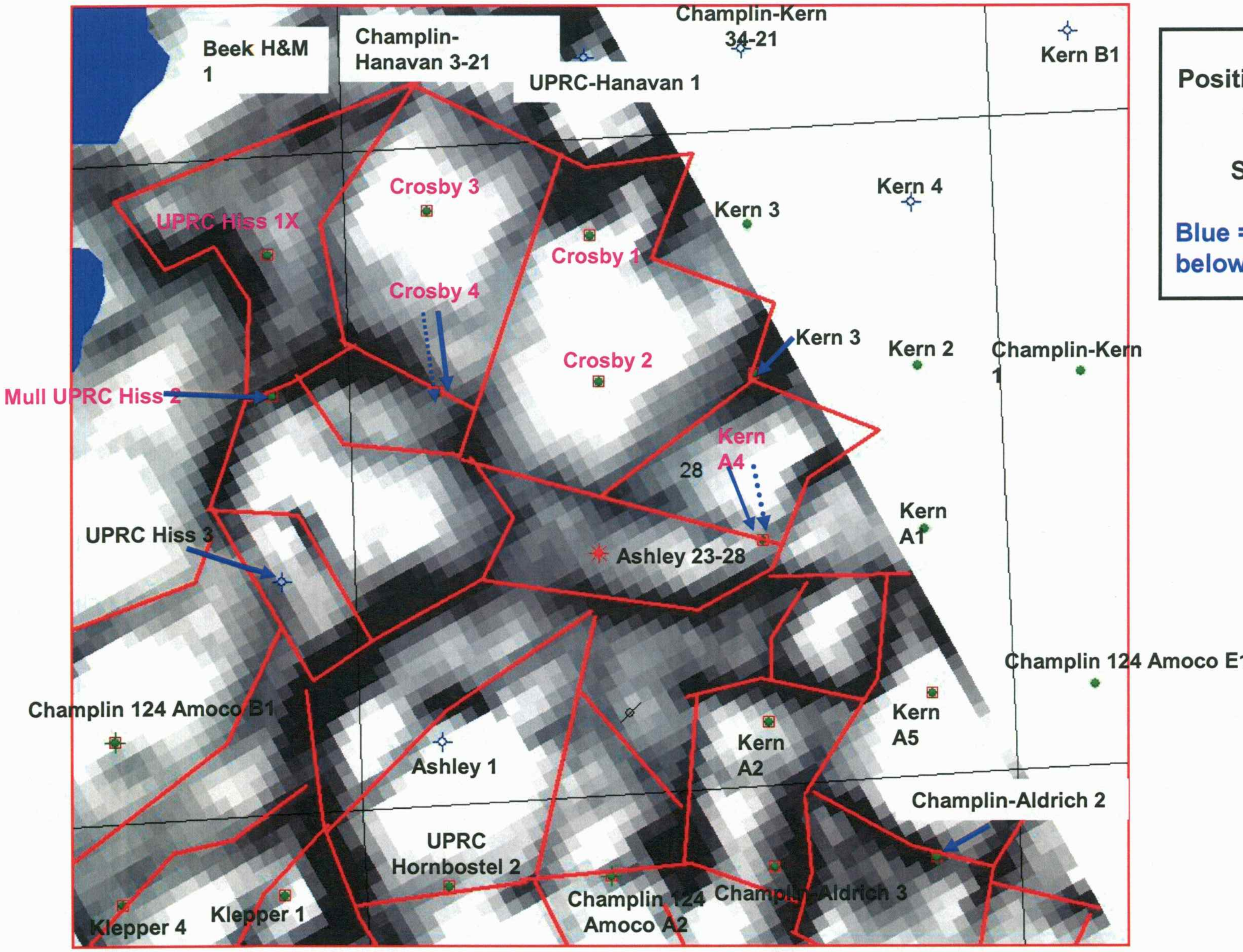


Figure 1: Spergen structure map over Smoky Creek field, Cheyenne County, Colorado.



Positive Curvature Map - Interpreted Lineaments Superimposed

Blue = Top of Spergen below OWC.

Figure 2: Shades of grey map positive curvature calculated from 3D-seismic data over Smoky Creek field. Interpreted lineaments have been superimposed to indicate possible compartmentalization of the reservoir.

		1st Prod		MBO	MBW									
		Completion		Cum	Cum	Spr A ------------------			Spr B --------------			Spr C ---------------		
UWI	Well Name	DATE	Elev	Oil	Wtr	H, ft	Phi	Sw	H, ft	Phi	Sw	H, ft	Phi	Sw
15-017-06138	Champlin Kern 1	12/13/1973	4241	1.9	363.4									
15-017-06143	Kern A1	3/22/1974	4249	333.5	381.6									
		3/22/1974												
15-017-06133	Crosby 1	5/29/1973	4215	255.2	1950.6	2	0.11	0.36	2	0.12	0.39	2.5	0.12	0.4
05-017-06134	Kern 1	6/28/1973	4229	74	1067.1	5.5	0.122	0.38	1.5	0.131	0.338			
15-017-07409	Mull UPRC-HISS 2	7/6/1994	4259	80.9	1365.8	8	0.11	0.36						
15-017-07395	Mull UPRC-HISS 1-X	10/6/1993	4227	228	938.2	15.5	0.134	0.153	3	0.087	0.49			
05-017-07392	Crosby 4	9/16/1993	4241	64.2	1105.5	8.5	0.117	0.393						
05-017-07376	Crosby 3	8/4/1993	4209	209	216.2	9	0.133	0.278						
05-017-07337	Crosby 2	12/8/1992	4257	97.8	888.4	13.5	0.122	0.236	9	0.109	0.35	4	0.092	0.486
05-017-07293	Kern A4	2/26/1992	4258	85.8	99.9	9.5	0.087	0.305						
05-017-07292	Kern 3	3/27/1992	4193	101.2	272.3	7	0.096	0.364	8	0.131	0.288			
05-017-07239	Kern 2	9/25/1991	4223	173.6	282.4	2.5	0.096	0.416	7	0.152	0.274			

Cut-offs applied: Phi = 8%, Sw = 52%, Vshale = 0.45, BVW = 0.049

D&A Wells:

Beek H&M and UPRC Hiss 3 – NO PAY using these cut-offs.

UPRC Hanavan 1 - 4 ft pay in Spergen B using these cut-offs. (Well considered for recompletion by MULL – Jun 2008.)

Kern 4A – Nphi log NA. Phi calculated using Dphi vs Avg(D&Nphi). If calculated phi was less by 2 units, then NO PAY found using these cut-offs

Figure 3: Summary of wireline log analysis for Smoky Creek field wells.

		Completion	KB	DST 1	DST 1	Subsea	Subsea	Rec	DST 2	DST 2	Subsea	Subsea	
UWI	Well Name	DATE	Elev	From	To	From	To		From	To	From	To	Rec
15-017-06138	Champlin Kern 1	12/13/1973	4251	5404	5443	-1153	-1192	CO, SMO, FCO, MO, OCRM, OCM, MW					
15-017-06143	Kern A1	3/22/1974	4259	5366	5409	-1107	-1150	SOCM	5405	5440	-1146	-1181	M
		3/22/1974											
15-017-06133	Crosby 1	5/29/1973	4225	5357	5387	-1132	-1162	G, CGO, SMO	5387	5411	-1162	-1186	G, CGO, GOM
		5/29/1973											
05-017-06134	Kern 1	6/28/1973	4239	5347	5390	-1108	-1151	CGO, MGO					
15-017-07409	Mull UPRC-HISS 2	7/6/1994	4271	5404	5450	-1133	-1179	GIP, GMCO, GOCM, OCM					
15-017-07395	Mull UPRC-HISS 1-X	10/6/1993	4239	5345	5415	-1106	-1176	MCO, MCGO, GOCM					
05-017-07392	Crosby 4	9/16/1993	4253	5387	5432	-1134	-1179	GO, SMCGO, HGOCM					
05-017-07376	Crosby 3	8/4/1993	4221	5330	5395	-1109	-1174	GIP, CGO, MCGO, SMCGO, VSOCM					
05-017-07337	Crosby 2	12/8/1992	4269	5385	5450	-1116	-1181	DM, WM, MWWTO					
05-017-07293	Kern A4	2/26/1992	4270	5360	5430	-1090	-1160	CO, HOCM, GOCM, GMCO					
05-017-07292	Kern 3	3/27/1992	4205	5306	5373	-1101	-1168	MCO					
05-017-07239	Kern 2	9/25/1991	4235	5340	5410	-1105	-1175	GIP, CGO, HGCMO					

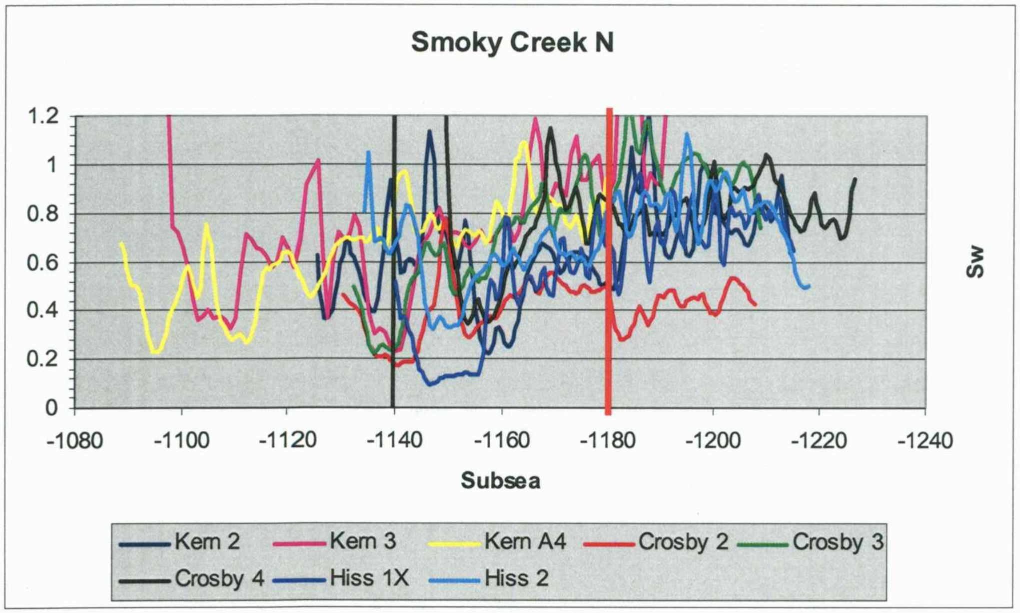
No wtr prod when test interval stops at	-1179	subsea
Wtr prod when test interval extends to atleast	-1181	subsea
Estimated OWC	-1180	subsea

No water production when test interval stops at -1179 feet

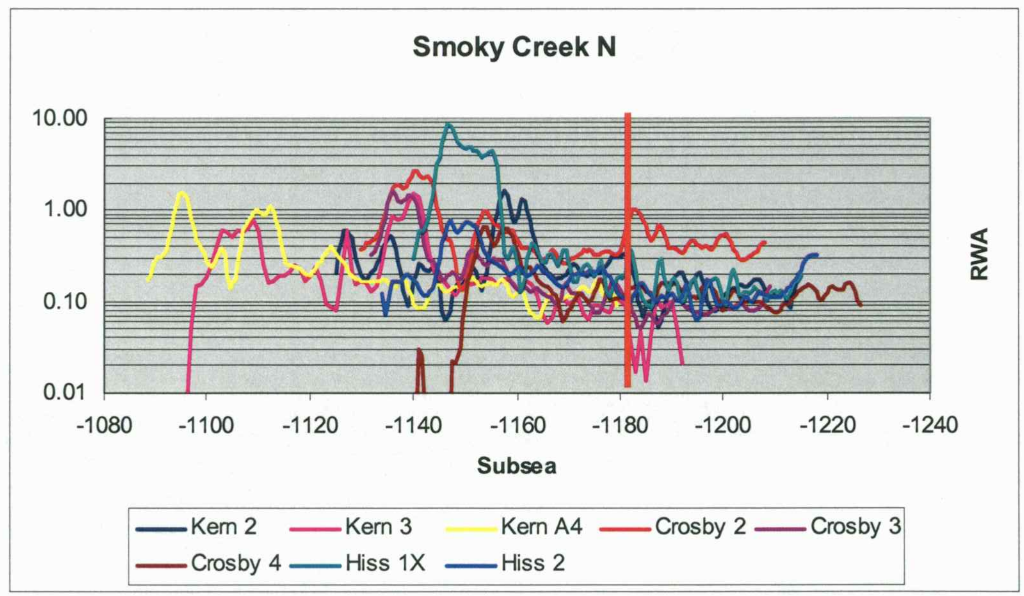
Water produced when test interval exceeds -1181 feet

1st estimate of OWC = -1180 feet

Figure 4: Determination of oil-water contact (OWC) from DST fluid recovery data.



A.



B.

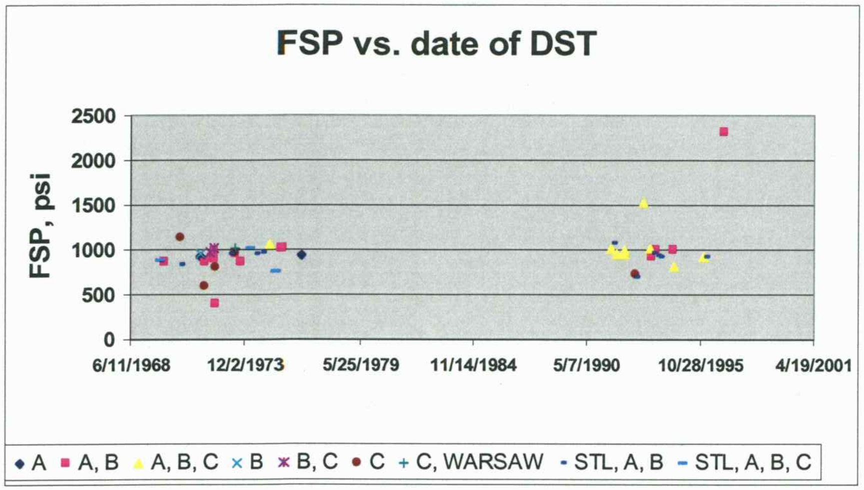
Figure 5: Plots showing changes in water saturation and Rwa with depth in Smoky Creek wells.

		1st Prod		MBO	MBW										Pfeffer		
		Completion		Cum	Cum	Spr A -------------------			Spr B ---------------			Spr C ----------------			MBO		
UWI	Well Name	DATE	Elev	Oil	Wtr	H, ft	Phi	Sw	H, ft	Phi	Sw	H, ft	Phi	Sw	HC Vol	RF	RF - His Match
15-017-06138	Champlin Kern 1	12/13/1973	4241	1.9	363.4	No Logs Available											
15-017-06143	Kern A1	3/22/1974	4249	333.5	381.6	No Logs Available											
		3/22/1974															
15-017-06133	Crosby 1	5/29/1973	4215	255.2	1950.6	2	0.11	0.36	2.5	0.12	0.39	2.5	0.12	0.4	142.9	178.6	123.6
05-017-06134	Kern 1	6/28/1973	4229	74	1067.1	5.5	0.122	0.38	1.5	0.131	0.338				163.4	45.3	45.3
15-017-07409	Mull UPRC-HISS 2	7/6/1994	4259	80.9	1365.8	8	0.11	0.36							166.6	48.6	42.4
15-017-07395	Mull UPRC-HISS 1-X	10/6/1993	4227	228	938.2	15.5	0.134	0.153	3	0.087	0.49				561.5	40.6	35.4
05-017-07392	Crosby 4	9/16/1993	4241	64.2	1105.5	8.5	0.117	0.393							178.5	36.0	33.4
05-017-07376	Crosby 3	8/4/1993	4209	209	216.2	9	0.133	0.278							255.6	81.8	66.7
05-017-07337	Crosby 2	12/8/1992	4257	97.8	888.4	13.5	0.122	0.236	9	0.109	0.35	4	0.092	0.486	658.1	14.9	15.6
05-017-07293	Kern A4	2/26/1992	4258	85.8	99.9	9.5	0.087	0.305							169.9	50.5	33.5
05-017-07292	Kern 3	3/27/1992	4193	101.2	272.3	7	0.096	0.364	8	0.131	0.288				358.1	28.3	28.3
05-017-07239	Kern 2	9/25/1991	4223	173.6	282.4	2.5	0.096	0.416	7	0.152	0.274				281.3	61.7	61.7

Based on 40-acre drainage, some wells show very high RE

Wells may be draining irregular sized (>40 acres) compartments

Figure 6: Estimated recovery efficiencies assuming 40-acre drainage for each Smoky Creek well.



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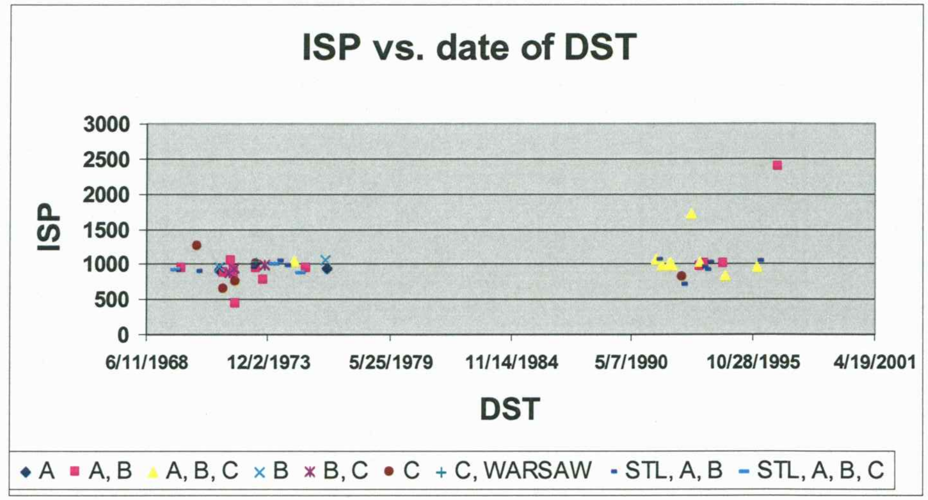
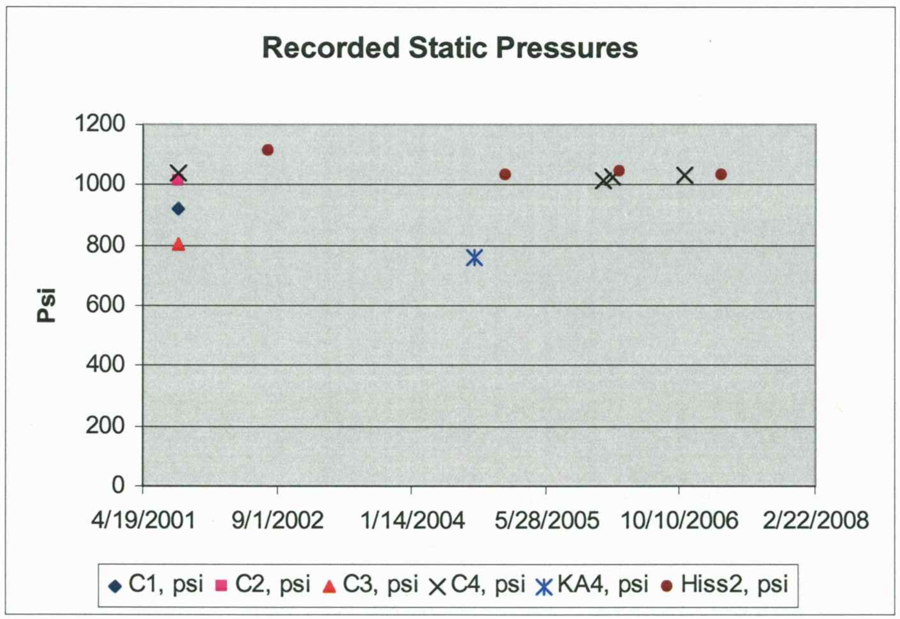


B.



C.

Figure 7: A) Final shut-in pressures recorded in Smoky Creek and Cheyenne Wells fields over time, B) final shut-in pressures recorded in Smoky Creek and Cheyenne Wells fields over time, and C) extended static pressures recorded in Smoky Creek field wells.

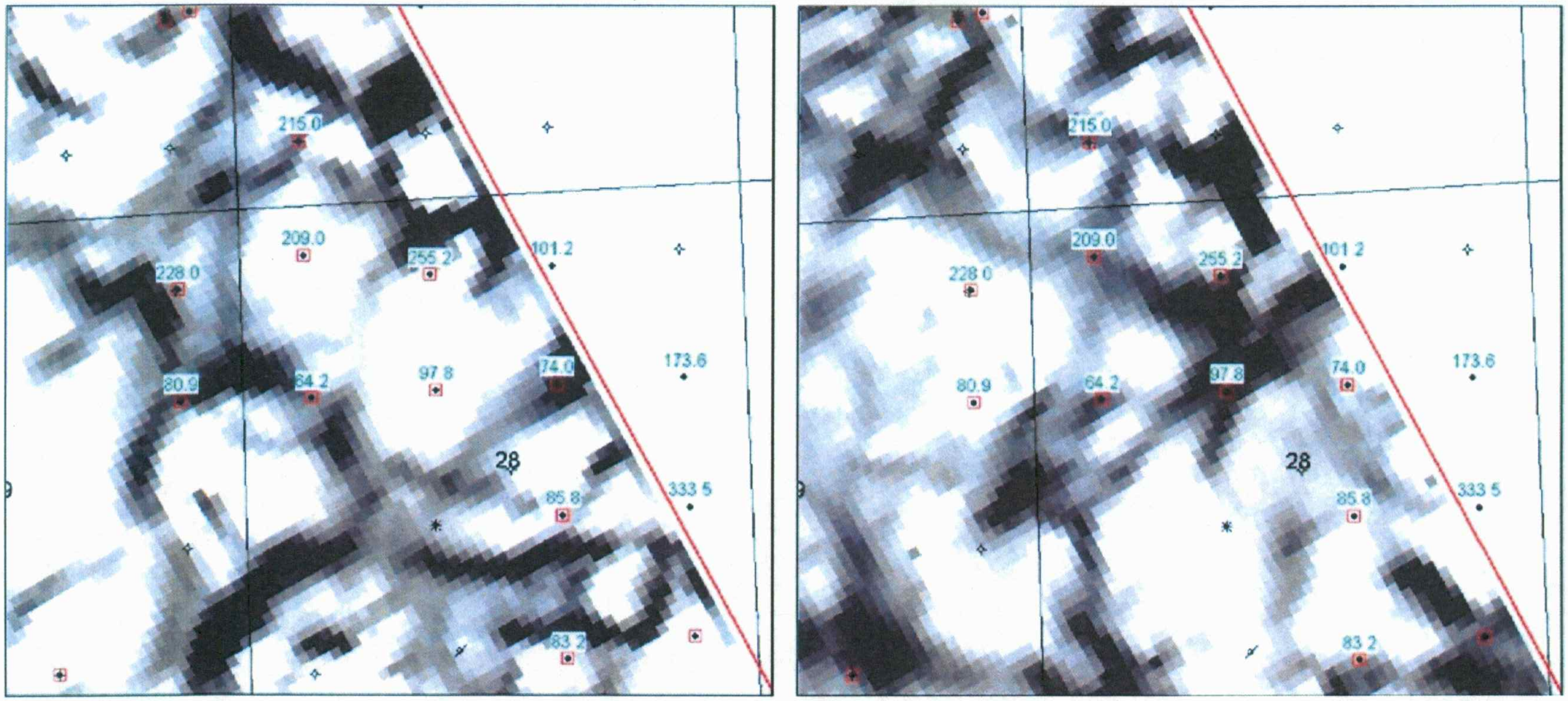


Figure 8: Most positive curvature (left) and most negative curvature (right) for Smoky Creek field, extracted along the approximate level of the top of Spergen. Cumulative oil production for Spergen producing wells is annotated in green.

Reservoir Model - Simulator

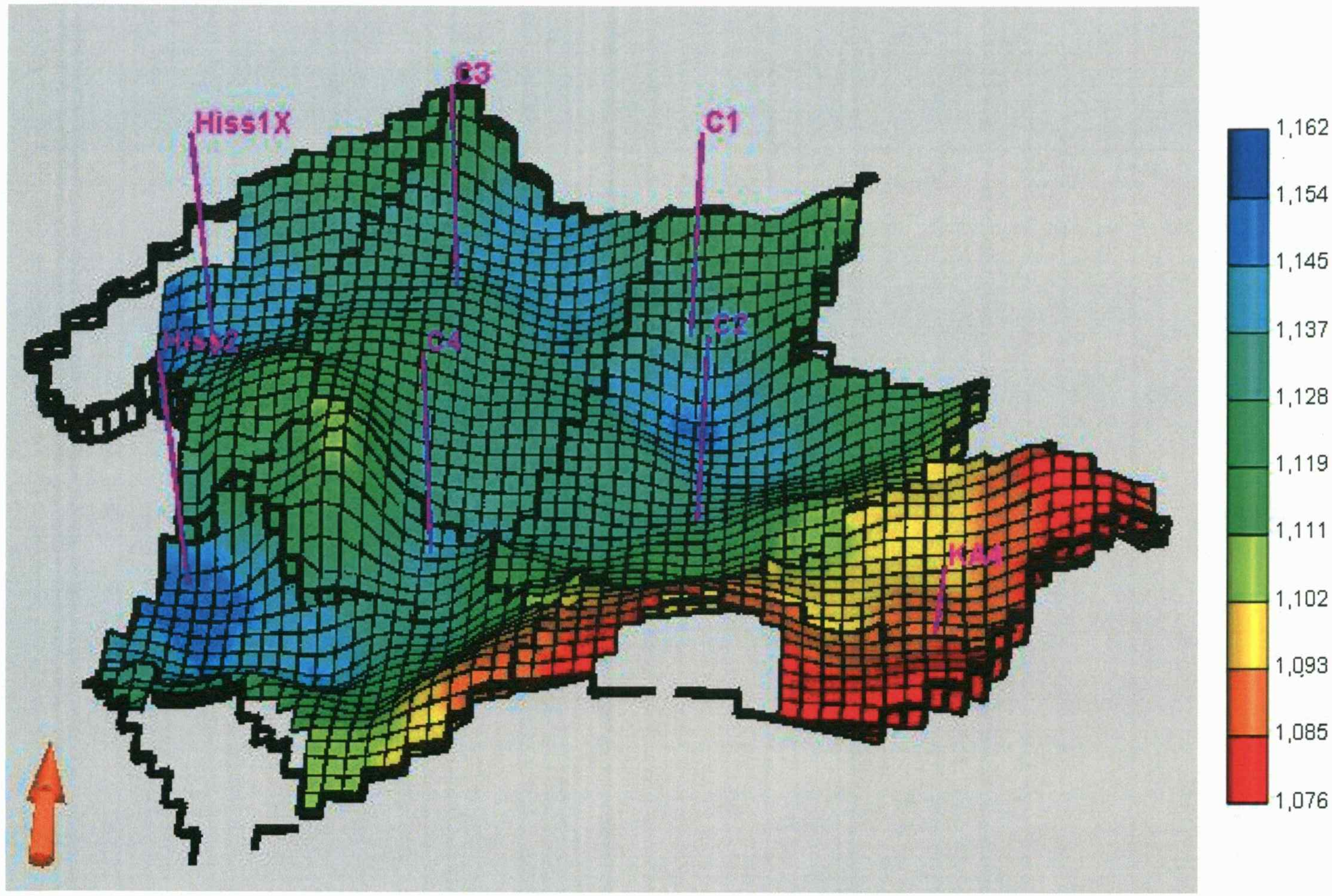


Figure 9: 3 layer reservoir simulation model for the study area. The well names and location are shown in magenta on the (subsea feet) structure map along with the compartment boundaries.

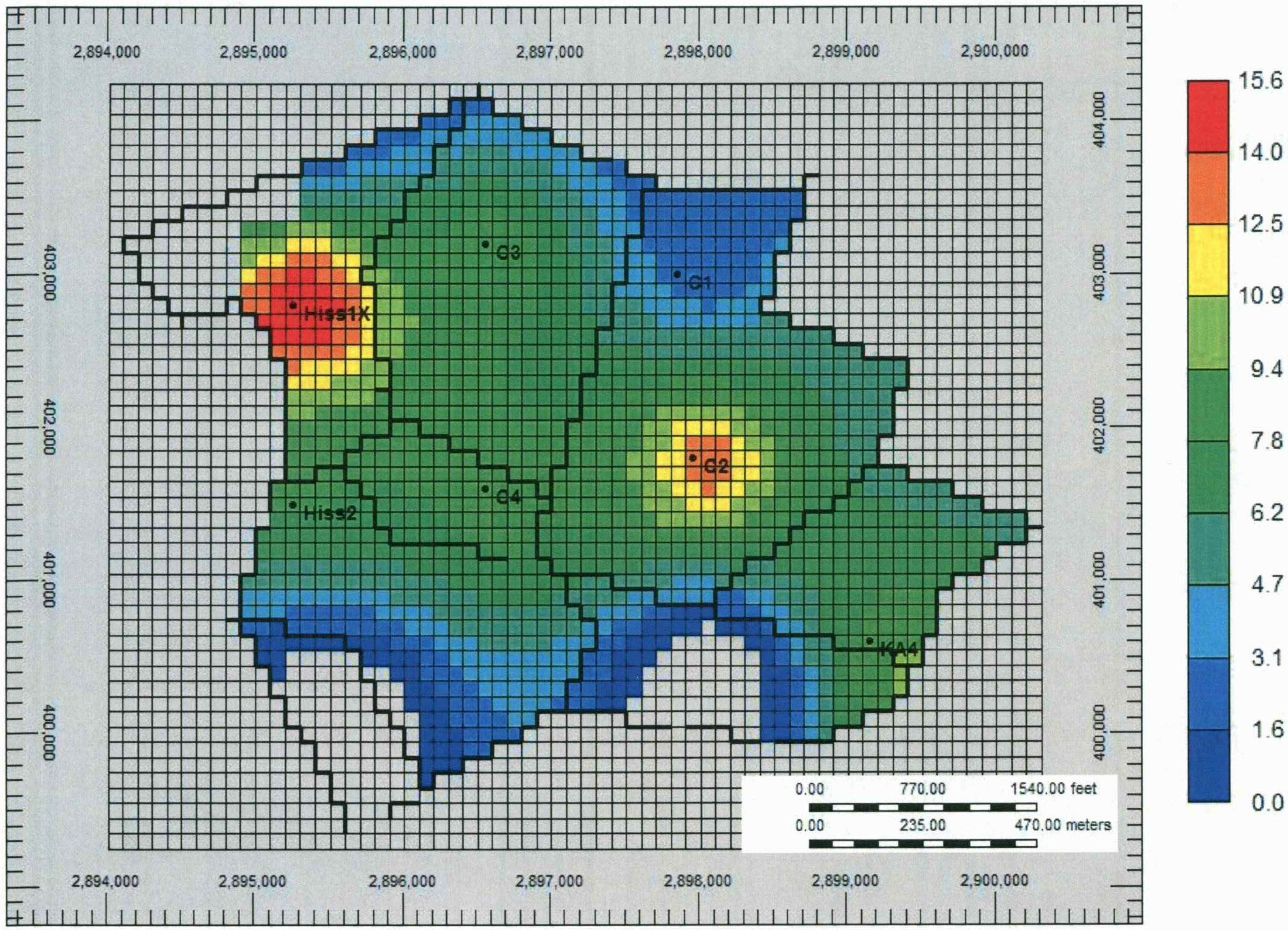


Figure 10: Effect pay (thickness, feet) map of the major pay zone (Spergen A) in the Smoky Creek field.

A.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

B.

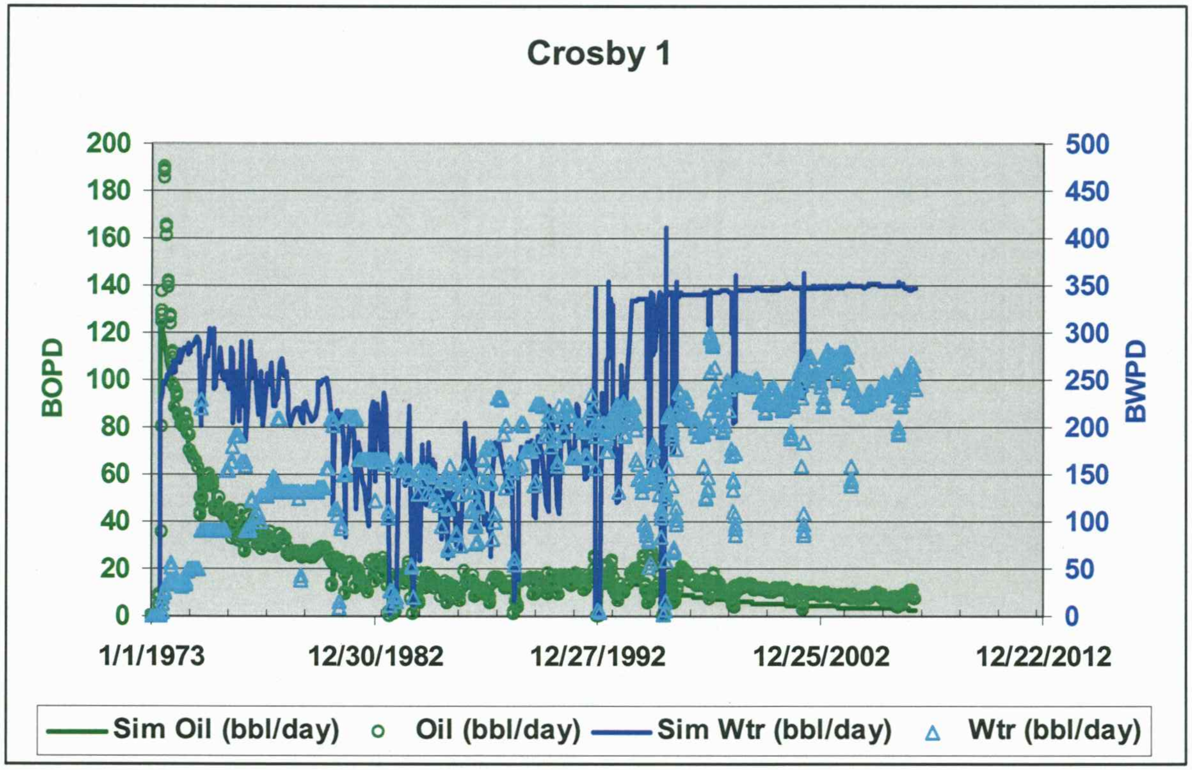
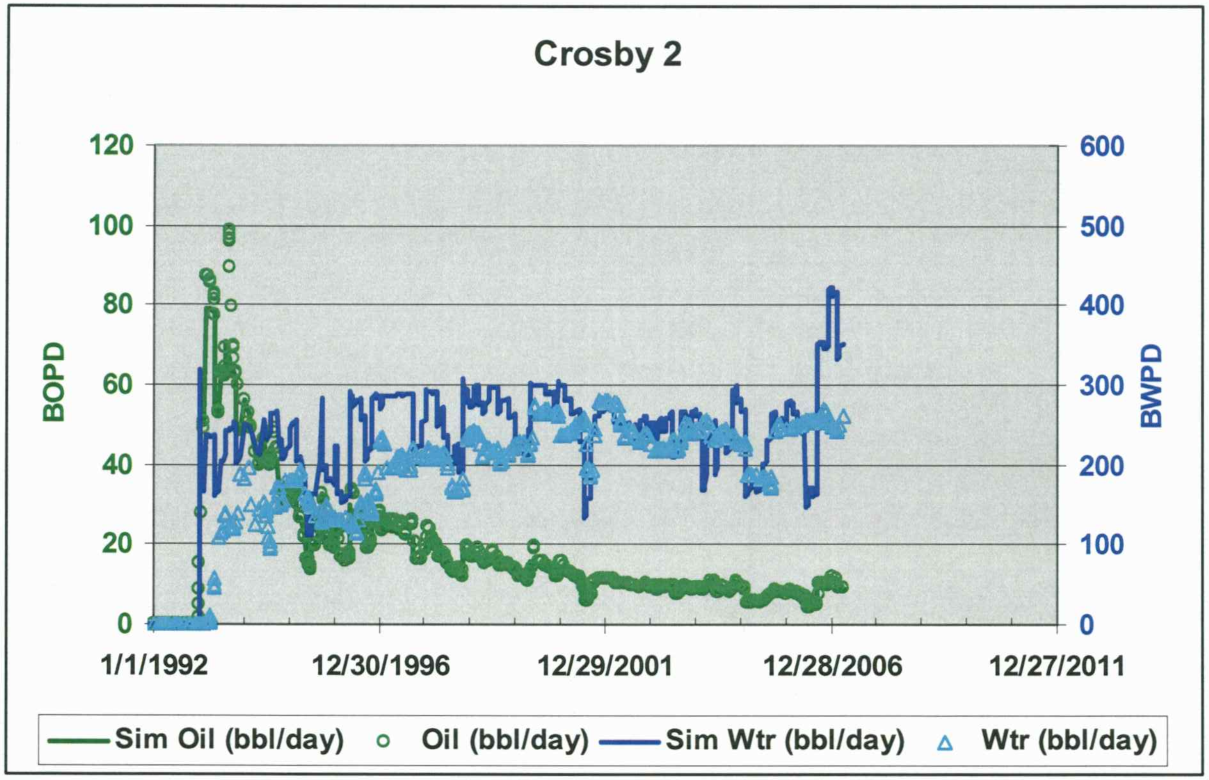


Figure 11: History match of Crosby 1 well performance.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

A.



B.

Figure 12: History match of Crosby 2 well performance.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

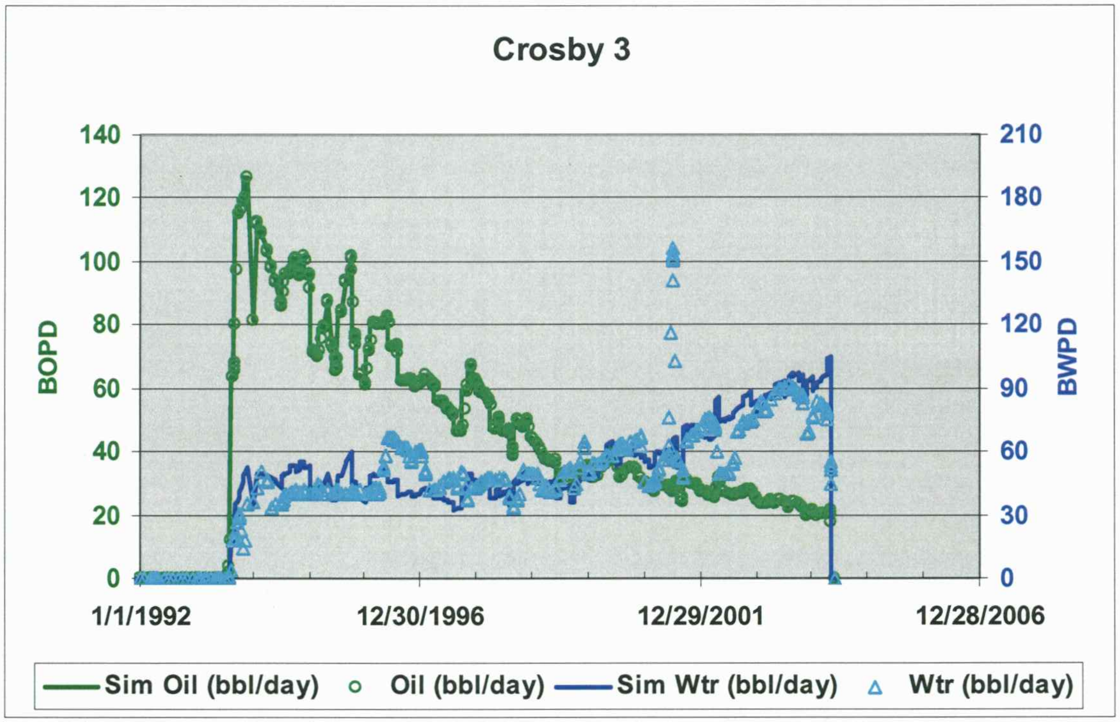


Figure 13: History match of Crosby 3 well performance.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

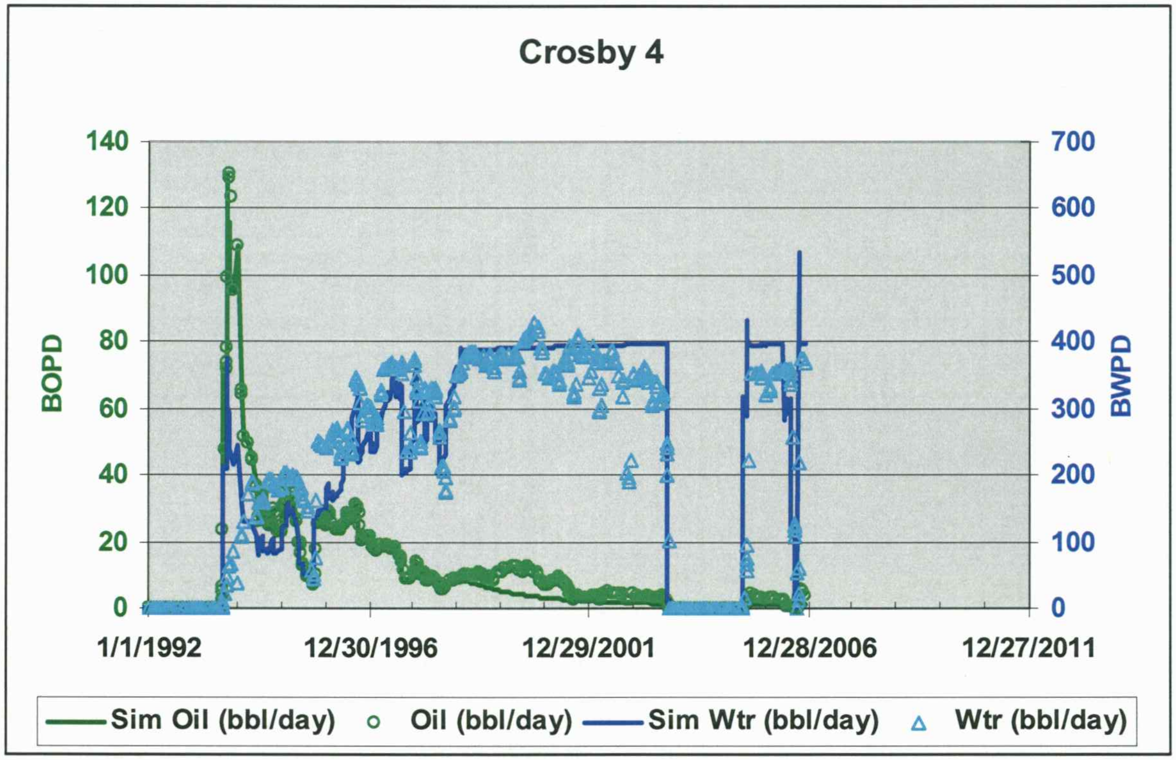
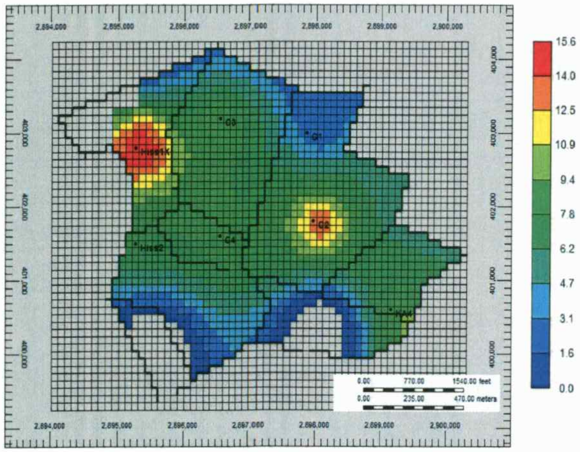


Figure 14: History match of Crosby 4 well performance.



Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

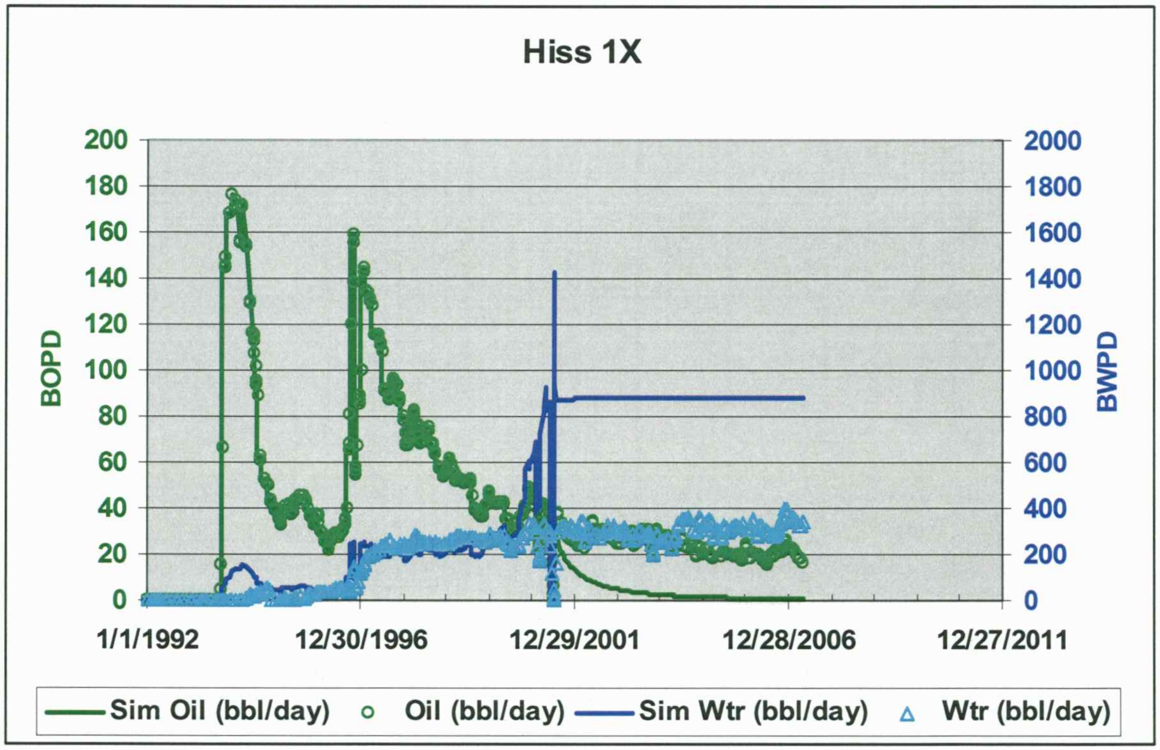


Figure 15: History match of UPRC Hiss 1X well performance.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

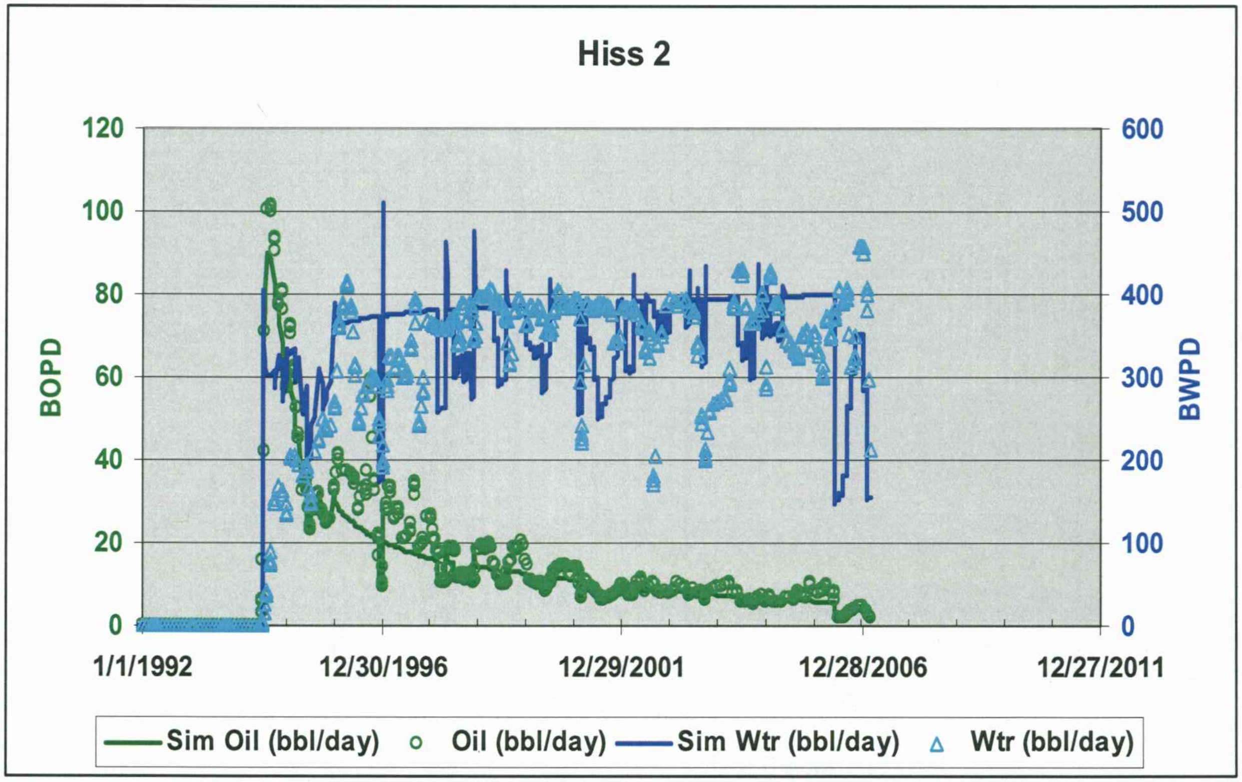


Figure 16: History match of UPRC Hiss 2 well performance.

Well Name	Start	Initial Perf	Later Perf	Oil, MBO	Wtr, MBW
Crosby 1	6/1/1973	Spr A, B, & C		255.2	1950.6
Mull UPRC-HISS 2	7/1/1994	Spr A		80.9	1365.8
Mull UPRC-HISS 1-X	10/1/1993	Spr A		228	938.2
Crosby 4	9/1/1993	Spr A		64.2	1105.5
Crosby 3	8/1/1993	Spr A	Plugged Spr	201	215
Crosby 2	1/1/1993	Spr B	Spr A	97.8	888.4
Kern A4	3/1/1992	Spr A		85.8	99.9

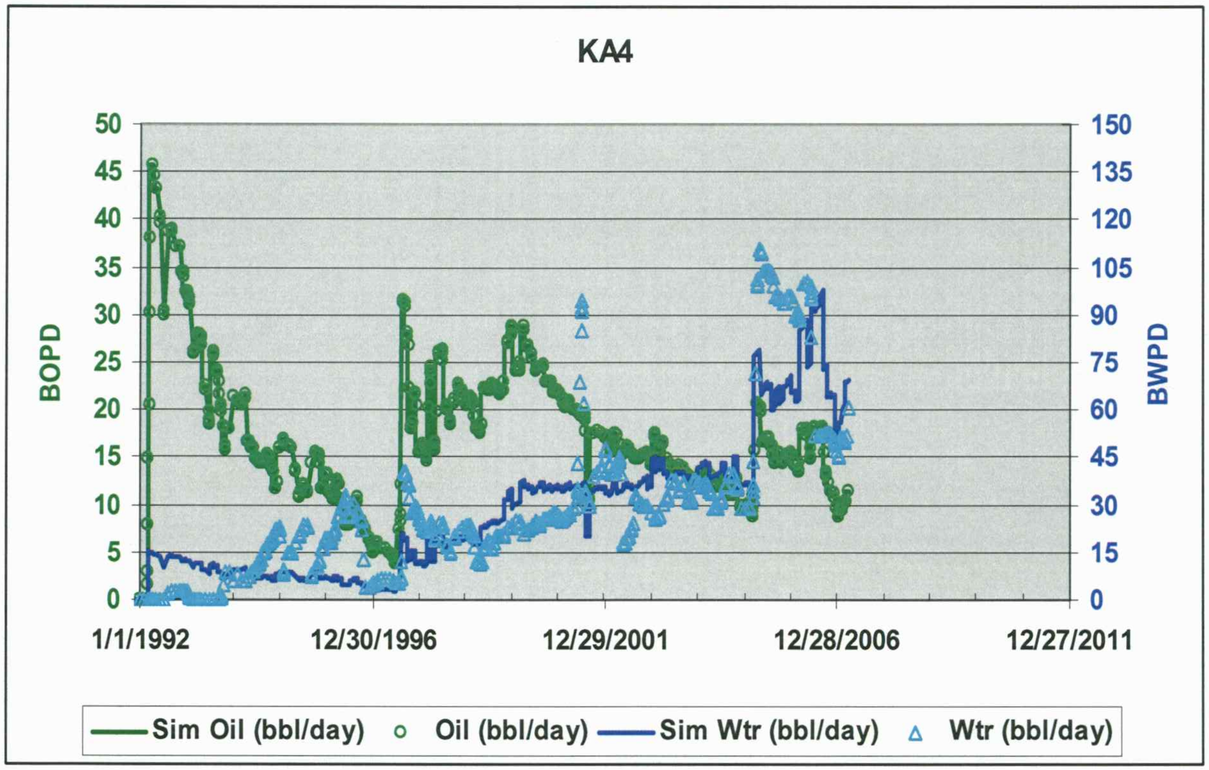


Figure 17: History match of Kern A4 well performance.

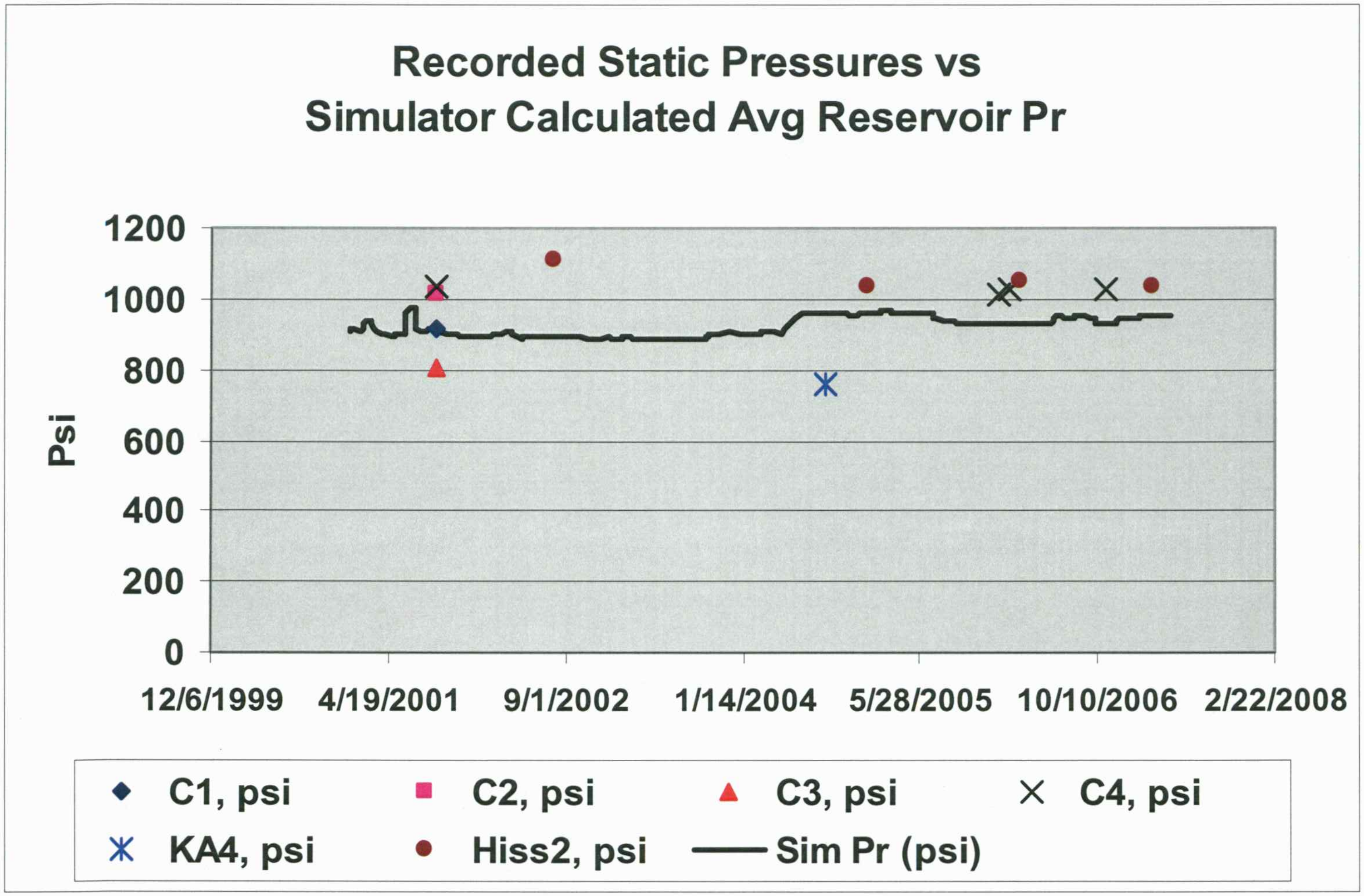


Figure 18: Match between simulation-derived average reservoir pressure with that calculated from fluid level buildup upon extended shut-in of wells.

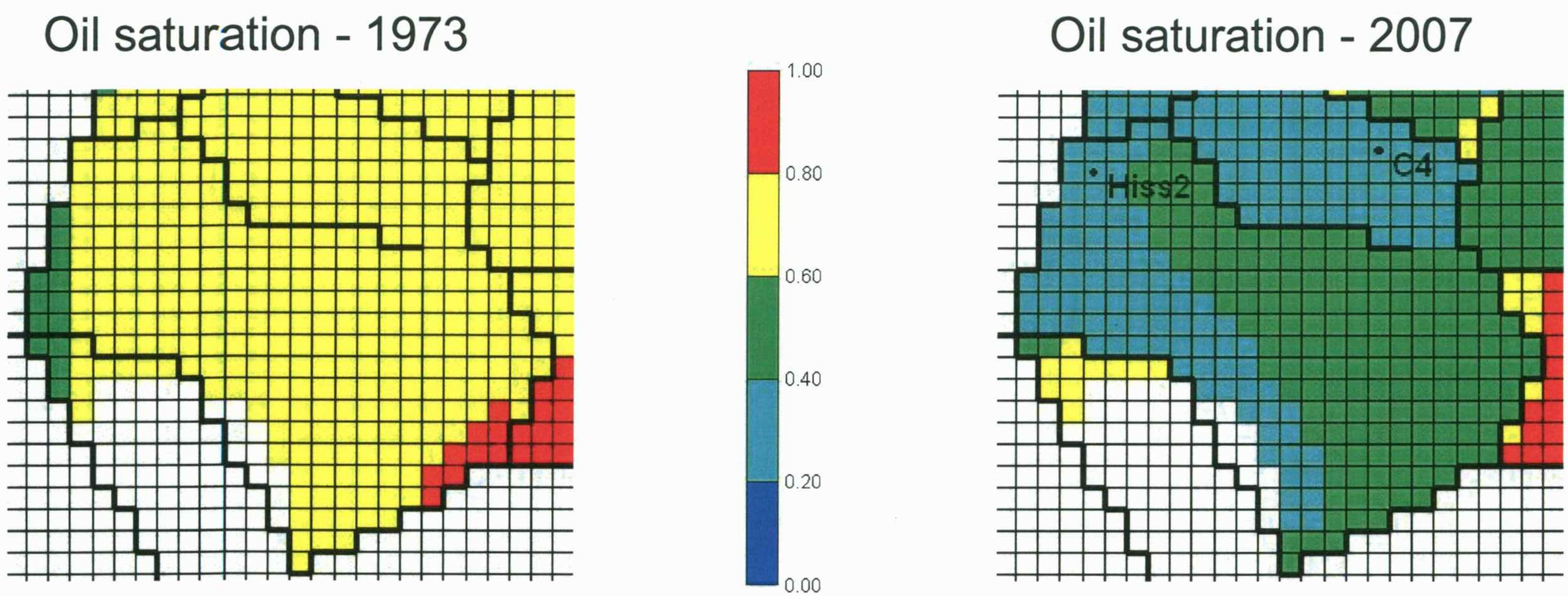


Figure 19: Oil saturation distribution in the compartment housing the Hiss 2 well in 1973 and that estimated from simulation results as of 2007. By 2007, the oil saturation in the green areas of the compartment had fallen to 0.48 from an initial oil saturation of 0.74 (in 1973).

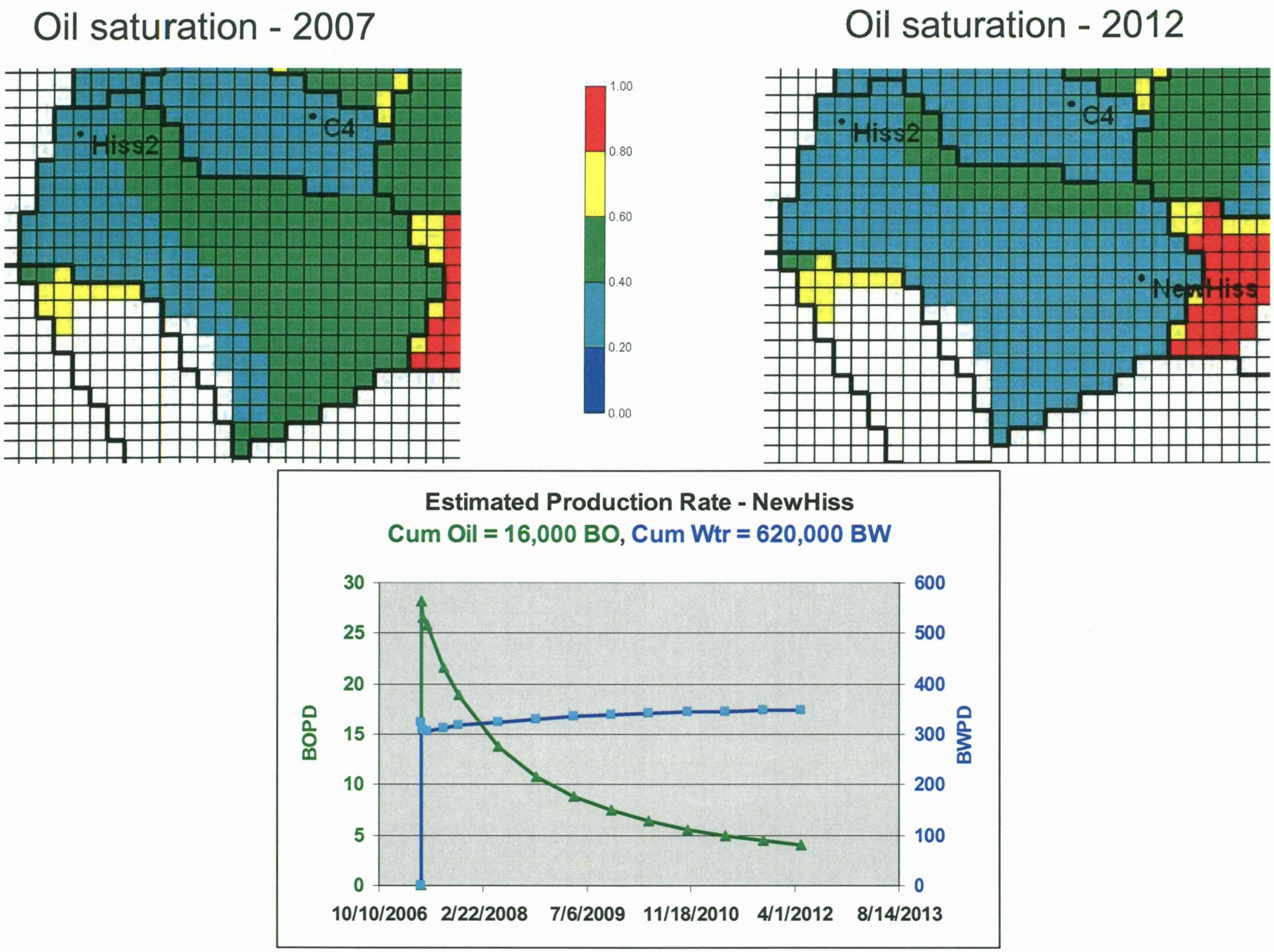


Figure 20: Simulator estimated oil saturation in the Hiss 2 compartment as of May 2007 and as of May 2012 after production onset at the infill well (NewHiss) assuming Hiss 2 to be simultaneously shut in. Also, estimated productivity from the NewHiss well as calculated from simulation output has been displayed.

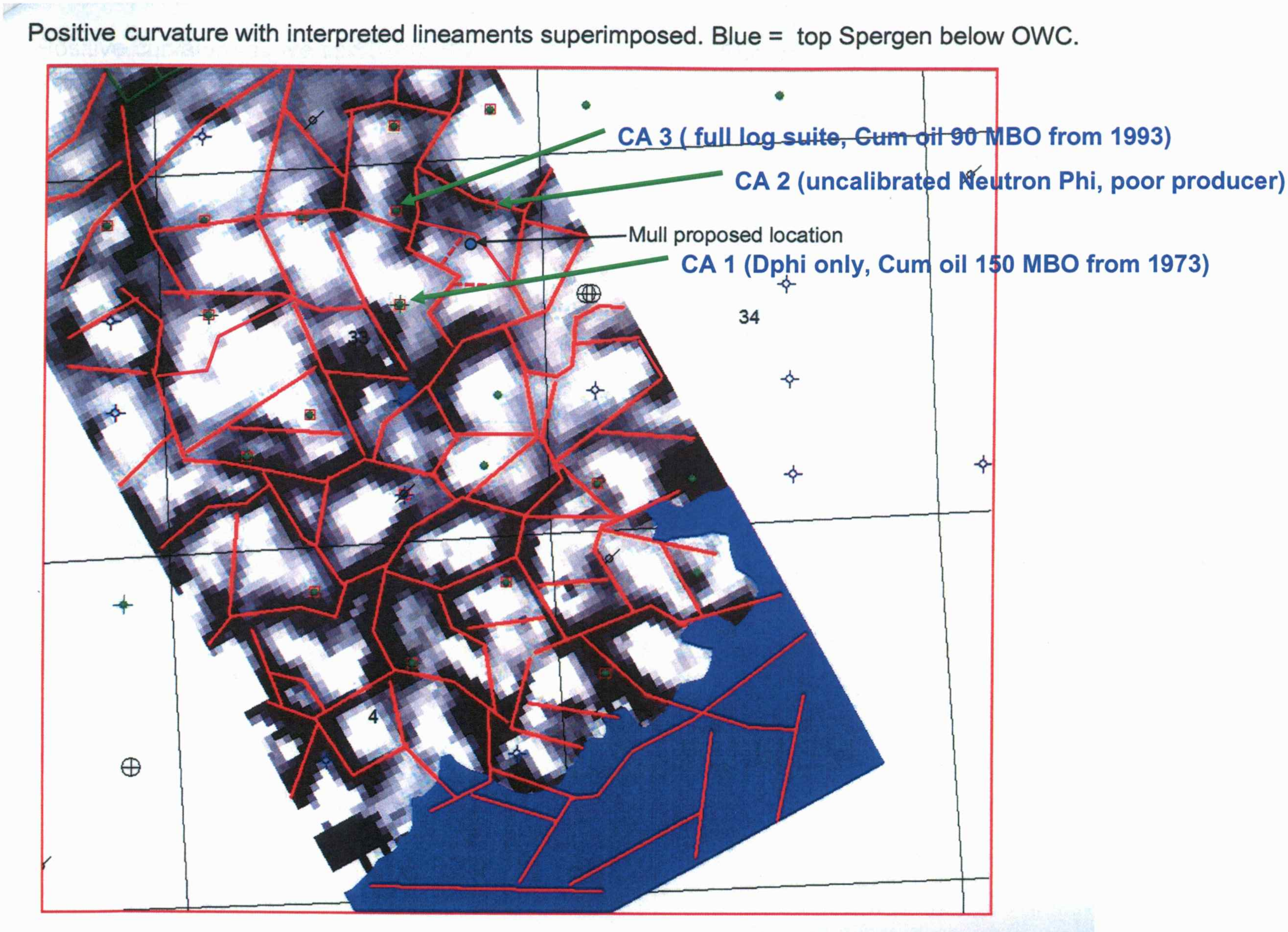
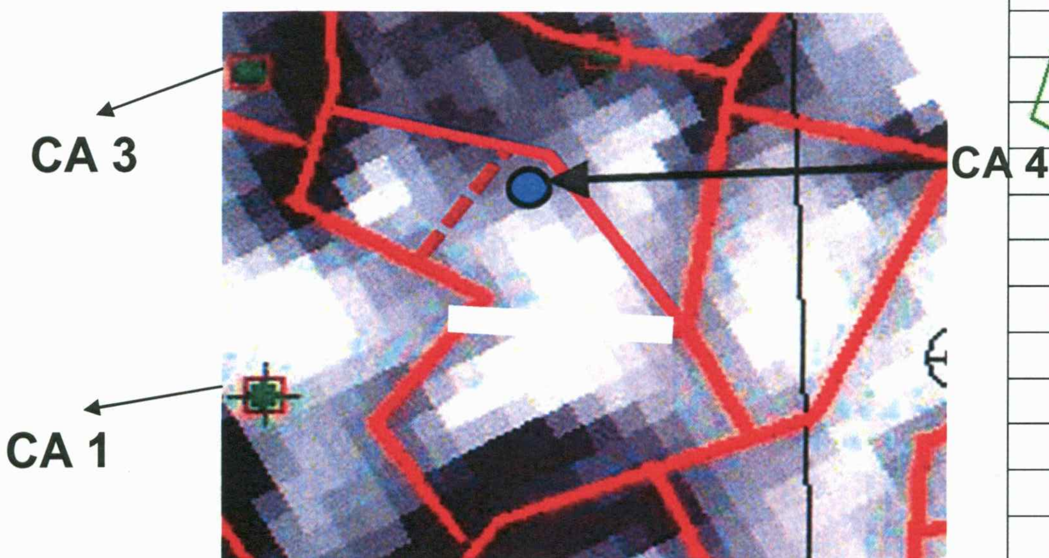


Figure 21: Positive curvature map with interpreted lineaments extended over the Cheyenne Wells field located adjacent and to the south of the Smoky Creek field.

Big Drainage Area – Bounded by unbroken red lines

Medium Drainage Area – Bounded by broken red line to the NW



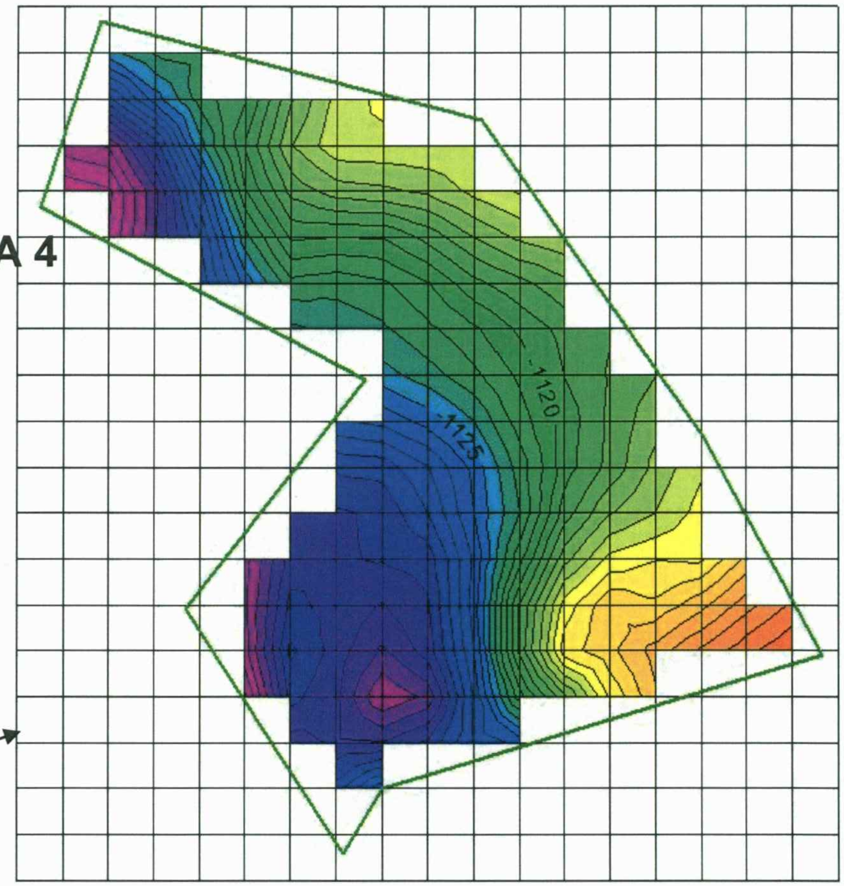


Figure 22: The Champlin Aldrich 4 (CA 4) reservoir compartment that was simulated to estimate productivity from the above named infill well.

Champlin Aldrich #3 – Log Analysis

CUT-OFFS	
PHICUT	0.08
SWCUT	0.52
VSHCUT	0.45
BVWCUT	0.049

ZN	DEPTH	THK	RT	PHI	RWA	RO	MA	SW	BVW	VSH	PAY	FLOW		Subsea
1	5412	0.5	87.6	0.036	0.11	61.28	2.11	0.836	0.030	0.182	0			-1113
2	5412.5	0.5	90.3	0.033	0.10	74.82	2.05	0.910	0.030	0.178	0			-1113.5
3	5413	0.5	66.8	0.031	0.06	82.69	1.94	1.113	0.035	0.237	0			-1114
4	5413.5	0.5	52.7	0.037	0.07	58.91	1.97	1.057	0.039	0.335	0			-1114.5
5	5414	0.5	51.4	0.048	0.12	35.33	2.12	0.829	0.039	0.447	0			-1115
6	5414.5	0.5	50.4	0.058	0.17	23.75	2.26	0.686	0.040	0.580	0			-1115.5
7	5415	0.5	39.4	0.063	0.16	20.14	2.24	0.715	0.045	0.684	0			-1116
8	5415.5	0.5	24.5	0.079	0.15	12.79	2.26	0.723	0.057	0.716	0			-1116.5
9	5416	0.5	24.2	0.095	0.22	8.91	2.42	0.607	0.058	0.689	0			-1117
10	5416.5	0.5	24.1	0.096	0.22	8.65	2.44	0.599	0.058	0.671	0			-1117.5
11	5417	0.5	24.5	0.090	0.20	9.83	2.38	0.634	0.057	0.671	0			-1118
12	5417.5	0.5	25.1	0.085	0.18	11.14	2.33	0.667	0.056	0.634	0			-1118.5
13	5418	0.5	25.7	0.075	0.14	14.18	2.23	0.743	0.056	0.543	0			-1119
14	5418.5	0.5	26.5	0.072	0.14	15.24	2.21	0.758	0.055	0.415	0			-1119.5
15	5419	0.5	26.8	0.070	0.13	16.10	2.19	0.775	0.055	0.327	0			-1120
16	5419.5	0.5	26.7	0.069	0.13	16.91	2.17	0.795	0.055	0.298	0			-1120.5
17	5420	0.5	26.4	0.069	0.13	16.68	2.17	0.795	0.055	0.351	0			-1121
18	5420.5	0.5	22	0.075	0.12	14.19	2.17	0.803	0.060	0.593	0			-1121.5
19	5421	0.5	21.6	0.086	0.16	10.91	2.28	0.710	0.061	0.857	0			-1122
20	5421.5	0.5	21.6	0.097	0.20	8.56	2.40	0.630	0.061	1.076	0			-1122.5
21	5422	0.5	21.7	0.113	0.28	6.29	2.57	0.538	0.061	1.108	0			-1123
22	5422.5	0.5	22	0.118	0.31	5.76	2.63	0.511	0.060	0.841	0			-1123.5
23	5423	0.5	22.4	0.120	0.33	5.52	2.66	0.496	0.060	0.556	0			-1124
24	5423.5	0.5	23.9	0.118	0.33	5.78	2.66	0.492	0.058	0.365	0			-1124.5
25	5424	0.5	29.8	0.114	0.39	6.14	2.73	0.454	0.052	0.264	0			-1125
26	5424.5	0.5	40	0.111	0.49	6.54	2.82	0.404	0.045	0.224	0.03			-1125.5
27	5425	0.5	50.3	0.107	0.57	7.01	2.88	0.373	0.040	0.178	0.03			-1126
28	5425.5	0.5	50.8	0.103	0.54	7.51	2.84	0.384	0.040	0.141	0.03			-1126.5
29	5426	0.5	51.3	0.098	0.49	8.31	2.78	0.402	0.039	0.114	0.03			-1127
30	5426.5	0.5	68.1	0.092	0.58	9.39	2.83	0.371	0.034	0.114	0.03			-1127.5
31	5427	0.5	86.9	0.082	0.59	11.80	2.80	0.368	0.030	0.113	0.03			-1128
32	5427.5	0.5	94.3	0.068	0.43	17.54	2.62	0.431	0.029	0.112	0			-1128.5
33	5428	0.5	100	0.049	0.24	33.28	2.37	0.576	0.028	0.110	0			-1129
34	5428.5	0.5	106	0.041	0.18	47.98	2.25	0.674	0.028	0.112	0			-1129.5
35	5429	0.5	109	0.037	0.15	58.32	2.19	0.731	0.027	0.093	0			-1130
36	5429.5	0.5	112	0.037	0.15	58.52	2.20	0.721	0.027	0.074	0			-1130.5
37	5430	0.5	112	0.043	0.20	43.67	2.30	0.625	0.027	0.063	0			-1131
38	5430.5	0.5	111	0.055	0.34	26.28	2.50	0.486	0.027	0.053	0			-1131.5
39	5431	0.5	109	0.065	0.46	18.86	2.64	0.416	0.027	0.042	0			-1132
40	5431.5	0.5	104	0.084	0.74	11.30	2.90	0.329	0.028	0.037	0.03			-1132.5
41	5432	0.5	99	0.095	0.89	8.85	3.03	0.299	0.028	0.047	0.03			-1133
42	5432.5	0.5	95.6	0.117	1.31	5.83	3.30	0.247	0.029	0.062	0.04			-1133.5
43	5433	0.5	90.9	0.129	1.52	4.79	3.44	0.229	0.030	0.077	0.05			-1134
44	5433.5	0.5	89.6	0.128	1.46	4.89	3.41	0.234	0.030	0.093	0.05			-1134.5
45	5434	0.5	89.6	0.116	1.21	5.92	3.26	0.257	0.030	0.098	0.04			-1135
46	5434.5	0.5	92.3	0.109	1.11	6.68	3.19	0.269	0.029	0.082	0.04			-1135.5
47	5435	0.5	96.3	0.110	1.16	6.63	3.21	0.262	0.029	0.072	0.04			-1136
48	5435.5	0.5	96.3	0.113	1.23	6.25	3.25	0.255	0.029	0.069	0.04			-1136.5
49	5436	0.5	96.3	0.115	1.27	6.06	3.28	0.251	0.029	0.069	0.04			-1137
50	5436.5	0.5	95	0.113	1.21	6.28	3.25	0.257	0.029	0.061	0.04			-1137.5
51	5437	0.5	91.6	0.099	0.89	8.21	3.04	0.299	0.030	0.056	0.03			-1138
52	5437.5	0.5	92.3	0.083	0.63	11.71	2.83	0.356	0.029	0.065	0.03			-1138.5
53	5438	0.5	93	0.060	0.34	21.93	2.51	0.486	0.029	0.072	0			-1139
54	5438.5	0.5	95.6	0.059	0.33	22.95	2.50	0.490	0.029	0.061	0			-1139.5
55	5439	0.5	95.6	0.056	0.30	25.32	2.46	0.515	0.029	0.042	0			-1140
56	5439.5	0.5	95.6	0.055	0.29	26.66	2.44	0.528	0.029	0.037	0			-1140.5
57	5440	0.5	95	0.054	0.28	27.20	2.43	0.535	0.029	0.038	0			-1141
58	5440.5	0.5	87.6	0.056	0.27	25.91	2.42	0.544	0.030	0.042	0			-1141.5
59	5441	0.5	75.5	0.058	0.26	23.45	2.41	0.557	0.033	0.050	0			-1142

5441	0.5	75.5	0.058	0.26	23.45	2.41	0.557	0.033	0.050	0			-1142
5441.5	0.5	58.7	0.056	0.18	25.74	2.29	0.662	0.037	0.066	0			-1142.5
5442	0.5	53.7	0.050	0.13	32.09	2.17	0.773	0.039	0.103	0			-1143
5442.5	0.5	51.5	0.051	0.14	30.45	2.18	0.769	0.039	0.181	0			-1143.5
5443	0.5	49.5	0.056	0.15	25.81	2.23	0.722	0.040	0.381	0			-1144
5443.5	0.5	48.8	0.060	0.18	22.15	2.28	0.674	0.041	0.509	0			-1144.5
5444	0.5	41.4	0.068	0.19	17.52	2.32	0.650	0.044	0.535	0			-1145
5444.5	0.5	38.5	0.073	0.21	14.83	2.37	0.621	0.046	0.402	0			-1145.5
5445	0.5	38.6	0.079	0.24	12.73	2.44	0.575	0.046	0.302	0			-1146
5445.5	0.5	38.8	0.076	0.22	13.99	2.40	0.600	0.045	0.256	0			-1146.5
5446	0.5	40.8	0.072	0.21	15.26	2.37	0.612	0.044	0.252	0			-1147
5446.5	0.5	43.6	0.068	0.20	17.21	2.35	0.628	0.043	0.234	0			-1147.5
5447	0.5	48.6	0.066	0.21	18.47	2.36	0.616	0.041	0.208	0			-1148
5447.5	0.5	49.1	0.064	0.20	19.77	2.33	0.635	0.040	0.186	0			-1148.5
5448	0.5	49	0.062	0.19	21.03	2.30	0.655	0.040	0.190	0			-1149
5448.5	0.5	48.8	0.061	0.18	21.21	2.30	0.659	0.040	0.189	0			-1149.5
5449	0.5	48.2	0.064	0.20	19.67	2.33	0.639	0.041	0.173	0			-1150
5449.5	0.5	42.5	0.080	0.27	12.54	2.48	0.543	0.043	0.157	0			-1150.5
5450	0.5	37.2	0.095	0.33	8.95	2.60	0.490	0.046	0.144	0.02			-1151
5450.5	0.5	35.9	0.111	0.44	6.47	2.78	0.425	0.047	0.141	0.03			-1151.5
5451	0.5	34.7	0.129	0.58	4.80	2.97	0.372	0.048	0.141	0.04			-1152
5451.5	0.5	29.4	0.138	0.56	4.19	2.98	0.378	0.052	0.141	0			-1152.5
5452	0.5	27.9	0.136	0.51	4.34	2.93	0.394	0.054	0.131	0			-1153
5452.5	0.5	27.1	0.122	0.40	5.37	2.77	0.445	0.054	0.120	0			-1153.5
5453	0.5	24.5	0.114	0.32	6.20	2.63	0.503	0.057	0.122	0			-1154
5453.5	0.5	21.2	0.103	0.22	7.60	2.45	0.599	0.061	0.154	0			-1154.5
5454	0.5	19.4	0.094	0.17	9.02	2.32	0.681	0.064	0.196	0			-1155
5454.5	0.5	19	0.096	0.17	8.77	2.33	0.680	0.065	0.240	0			-1155.5
5455	0.5	18.8	0.099	0.18	8.20	2.36	0.661	0.065	0.272	0			-1156
5455.5	0.5	18.7	0.107	0.21	7.00	2.44	0.612	0.065	0.303	0			-1156.5
5456	0.5	19	0.110	0.23	6.65	2.48	0.591	0.065	0.324	0			-1157
5456.5	0.5	19.7	0.112	0.25	6.42	2.51	0.571	0.064	0.319	0			-1157.5
5457	0.5	20.1	0.113	0.26	6.22	2.54	0.556	0.063	0.266	0			-1158
5457.5	0.5	22.7	0.112	0.28	6.39	2.58	0.531	0.059	0.170	0			-1158.5
5458	0.5	23.3	0.108	0.27	6.85	2.55	0.542	0.059	0.114	0			-1159
5458.5	0.5	24.1	0.104	0.26	7.42	2.52	0.555	0.058	0.088	0			-1159.5
5459	0.5	26	0.100	0.26	7.97	2.51	0.553	0.055	0.101	0			-1160
5459.5	0.5	28.6	0.101	0.29	7.89	2.56	0.525	0.053	0.122	0			-1160.5
5460	0.5	29.3	0.103	0.31	7.47	2.60	0.505	0.052	0.133	0			-1161
5460.5	0.5	30.2	0.105	0.33	7.25	2.63	0.490	0.051	0.146	0			-1161.5
5461	0.5	30.8	0.108	0.36	6.82	2.68	0.470	0.051	0.141	0			-1162
5461.5	0.5	31.9	0.110	0.38	6.67	2.71	0.457	0.050	0.125	0			-1162.5
5462	0.5	38.8	0.110	0.47	6.57	2.81	0.411	0.045	0.112	0.03			-1163
5462.5	0.5	45.9	0.107	0.52	7.00	2.84	0.390	0.042	0.096	0.03			-1163.5
5463	0.5	46.3	0.104	0.50	7.47	2.80	0.401	0.042	0.082	0.03			-1164
5463.5	0.5	46.5	0.106	0.53	7.08	2.84	0.390	0.041	0.074	0.03			-1164.5
5464	0.5	46.5	0.108	0.54	6.85	2.86	0.384	0.041	0.071	0.03			-1165
5464.5	0.5	46.3	0.111	0.57	6.54	2.89	0.376	0.042	0.074	0.03			-1165.5
5465	0.5	44.3	0.110	0.54	6.55	2.87	0.385	0.043	0.082	0.03			-1166
5465.5	0.5	41.6	0.111	0.51	6.55	2.84	0.397	0.044	0.088	0.03			-1166.5
5466	0.5	30.4	0.110	0.37	6.61	2.69	0.467	0.051	0.103	0			-1167
5466.5	0.5	28.6	0.111	0.35	6.44	2.68	0.475	0.053	0.162	0			-1167.5
5467	0.5	25.7	0.112	0.32	6.38	2.64	0.498	0.056	0.248	0			-1168
5467.5	0.5	25	0.112	0.32	6.34	2.63	0.504	0.057	0.301	0			-1168.5
5468	0.5	24.3	0.110	0.29	6.60	2.59	0.521	0.057	0.189	0			-1169
5468.5	0.5	23.5	0.105	0.26	7.20	2.53	0.553	0.058	0.200	0			-1169.5
5469	0.5	23.1	0.096	0.21	8.61	2.42	0.611	0.059	0.093	0			-1170
5469.5	0.5	22.7	0.092	0.19	9.53	2.36	0.649	0.059	0.077	0			-1170.5
5470	0.5	22.2	0.090	0.18	9.85	2.34	0.666	0.060	0.111	0			-1171
5470.5	0.5	21.2	0.092	0.18	9.53	2.33	0.671	0.061	0.184	0			-1171.5
5471	0.5	20.6	0.095	0.19	8.83	2.36	0.654	0.062	0.298	0			-1172
5471.5	0.5	20.2	0.098	0.19	8.32	2.38	0.641	0.063	0.357	0			-1172.5
5472	0.5	18.8	0.101	0.19	7.77	2.39	0.644	0.065	0.351	0			-1173
5472.5	0.5	16.5	0.101	0.17	7.79	2.33	0.688	0.070	0.279	0			-1173.5
5473	0.5	16.1	0.103	0.17	7.61	2.33	0.688	0.071	0.237	0			-1174
5473.5	0.5	16	0.105	0.18	7.24	2.35	0.673	0.071	0.237	0			-1174.5
5474	0.5	16.1	0.110	0.19	6.62	2.40	0.642	0.071	0.245	0			-1175
5474.5	0.5	16.3	0.118	0.23	5.77	2.48	0.596	0.070	0.253	0			-1175.5
5475	0.5	16.4	0.122	0.25	5.34	2.53	0.571	0.070	0.245	0			-1176
5475.5	0.5	16.8	0.132	0.29	4.57	2.64	0.522	0.069	0.205	0			-1176.5
5476	0.5	17.8	0.132	0.31	4.61	2.67	0.510	0.067	0.178	0			-1177
5476.5	0.5	19.5	0.129	0.32	4.84	2.68	0.498	0.064	0.157	0			-1177.5
5477	0.5	23.7	0.121	0.35	5.46	2.69	0.481	0.058	0.162	0			-1178
5477.5	0.5	30.2	0.120	0.43	5.58	2.80	0.429	0.051	0.197	0			-1178.5
5478	0.5	30.6	0.119	0.43	5.67	2.79	0.431	0.051	0.264	0			-1179
5478.5	0.5	30.6	0.120	0.44	5.57	2.80	0.426	0.051	0.359	0			-1179.5
5479	0.5	30.1	0.122	0.45	5.37	2.82	0.422	0.052	0.421	0			-1180
5479.5	0.5	24.7	0.125	0.38	5.14	2.75	0.456	0.057	0.426	0			-1180.5
5480	0.5	14.9	0.128	0.24	4.91	2.54	0.574	0.073	0.341	0			-1181

Spergen A (L1)

H, ft	Avg Phi	Avg BVW	Avg Sw
9.5	0.11	0.032	0.30

Spergen B (L2)

H, ft	Avg Phi	Avg BVW	Avg Sw
5.5	0.11	0.044	0.40

Figure 23: Log analysis of Champlin Aldrich 3 well.

UNCERTAINTIES

Drainage Area

Big Compartment (Ba)

Medium Compartment (Ma)

Storage

Effective Pay (ft)

Avg Phi in pay

Avg Sw in pay

Flow

Horizontal Perm

Vertical Perm

Relative Permeability

Aquifer Charging

Figure 24: Petrophysical parameters controlling storage and flow.

ASSUMED STORAGE & FLOW PARAMETERS

Storage

		Area	Thickness, ft	Phi	Sw
Spergen A (Layer 1, L1)					
	High		11.9	0.13	0.2
	Medium		**9.5**	**0.11**	**0.3**
	Low		7.1	0.09	0.4
Spergen B (Layer 2, L2)					
	High		6.9	0.13	0.25
	Medium		**5.5**	**0.11**	**0.4**
	Low		4.1	0.09	0.45

Flow

		K	Kz	Rel K No.
Spergen A (Layer 1, L1)				
	High	75	3.75	10
	Medium	**60**	**3**	**4**
	Low	40	2	8
Spergen B (Layer 2, L2)				
	High	75	3.75	10
	Medium	**60**	**3**	**4**
	Low	40	2	8

Based on Smoky Creek History matches

Figure 25: Assumed values and ranges of petrophysical parameters for reservoir simulation of Champlin Aldrich 4 compartment.

SIMULATION RUNS – 18 Scenarios

For Big Drainage Area (Ba)	For Medium Drainage Area (Ma)
Hs Hf	Hs Hf
Hs Mf	Hs Mf
Hs Lf	Hs Lf
Ms Hf	Ms Hf
Ms Mf	Ms Mf
Ms Lf	Ms Lf
Ls Hf	Ls Hf
Ls Mf	Ls Mf
Ls Lf	Ls Lf

Figure 26: Series of simulation runs carried out for Champlin Aldrich 4 compartment.

BOPD – Averaged Annually

Min	21.0	11.5	8.8	7.1	6.0	5.2	4.6	4.2	3.8	3.5
Max	203.0	84.9	60.7	47.6	39.5	33.5	29.1	25.5	22.8	20.4

Rate, BOPD

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 Ma Hs Hf - O	157.8	71.2	50.7	39.7	33.1	27.9	24.0	20.9	18.5	16.4
2 Ma Hs Mf - O	143.5	65.0	46.7	36.7	30.8	26.2	22.7	20.0	18.0	16.2
3 Ma Hs Lf - O	114.6	55.3	40.1	31.8	26.6	22.8	19.8	17.7	16.0	14.6
4 Ma Ms Hf - O	68.0	34.5	25.2	20.0	16.7	14.3	12.4	10.9	9.8	8.8
5 Ma Ms Mf - O	61.1	31.4	23.0	18.2	15.3	13.2	11.5	10.2	9.2	8.4
6 Ma Ms Lf - O	50.7	26.3	19.5	15.6	13.0	11.2	9.9	8.8	8.0	7.4
7 Ma Ls Hf - O	28.8	15.3	11.4	9.1	7.7	6.6	5.9	5.3	4.7	4.3
8 Ma Ls Mf - O	25.6	13.8	10.3	8.3	7.0	6.0	5.4	4.8	4.4	4.0
9 Ma Ls Lf - O	21.0	11.5	8.8	7.1	6.0	5.2	4.6	4.2	3.8	3.5
2 Ba Hs Hf - O	203.0	84.9	60.7	47.6	39.5	33.5	29.1	25.5	22.8	20.4
3 Ba Hs Mf - O	185.4	78.2	56.1	44.1	36.6	31.2	27.3	24.2	21.8	19.7
4 Ba Hs Lf - O	152.0	66.4	47.9	37.8	31.6	27.0	23.5	21.1	19.1	17.4
5 Ba Ms Hf - O	88.3	41.8	30.2	23.8	20.0	17.0	14.9	13.2	12.0	10.8
6 Ba Ms Mf - O	81.6	37.3	27.5	21.8	18.2	15.7	13.8	12.3	11.2	10.2
7 Ba Ms Lf - O	68.8	31.6	23.5	18.8	16.0	13.7	12.1	10.9	9.9	9.0
8 Ba Ls Hf - O	37.3	18.8	13.8	11.0	9.2	8.0	7.1	6.3	5.8	5.2
9 Ba Ls Mf - O	33.7	17.2	12.8	10.2	8.5	7.3	6.6	5.9	5.3	4.9
10 Ba Ls Lf - O	28.4	14.3	10.7	8.7	7.4	6.4	5.7	5.2	4.8	4.4

Figure 27: Summary of simulation results showing daily oil production averaged from annual cumulative production.

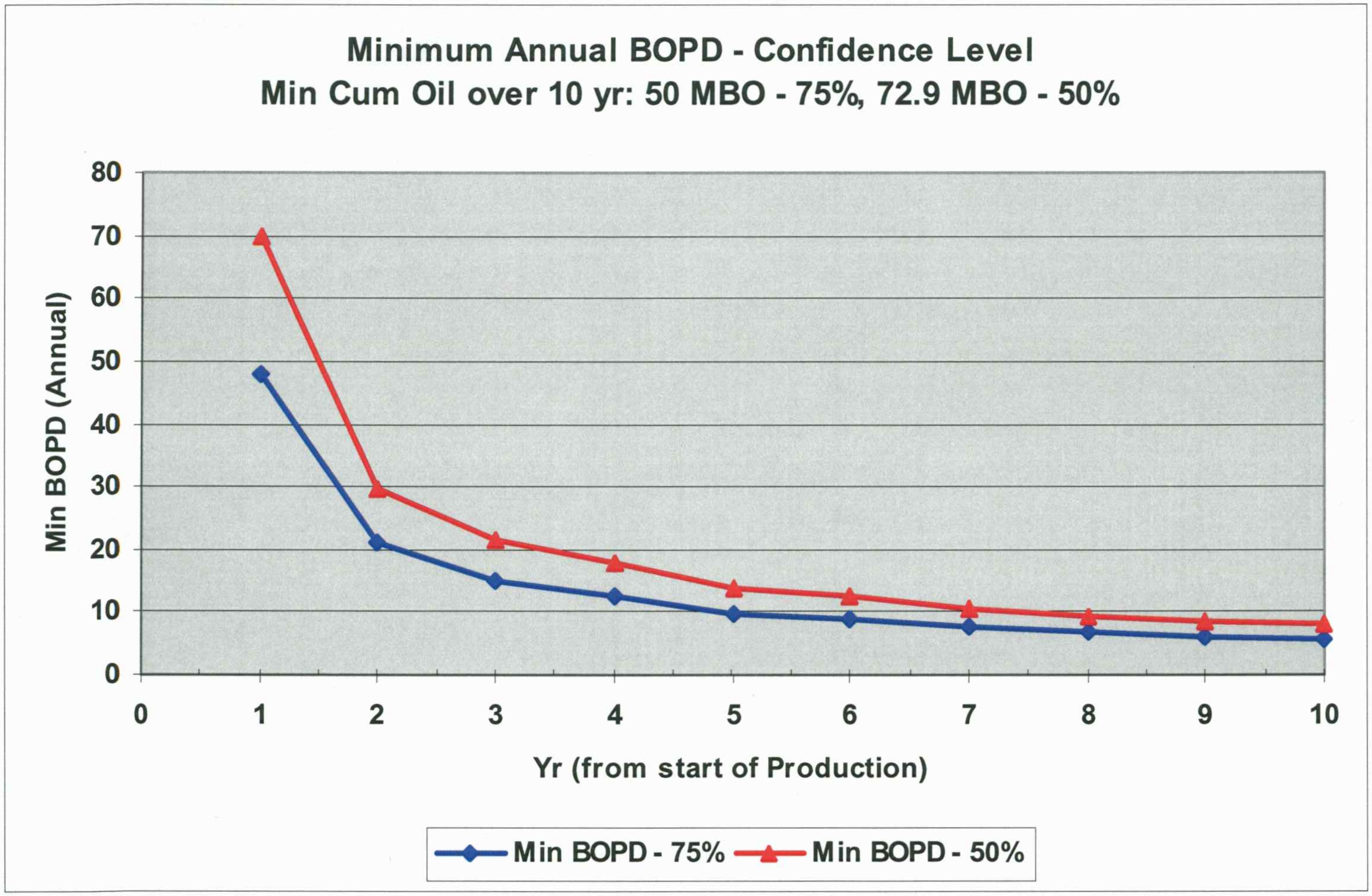


Figure 28: Minimum average annual daily oil production rate calculated with 50 and 75% confidence for Champlin Aldrich 4 well.

Min	7681	4213	3197	2587	2187	1888	1694	1523	1389	1272
Max	74101	30978	22165	17383	14423	12210	10625	9308	8323	7434

Annual Prod BOPY

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1 Ma Hs Hf - O	57588	26005	18521	14485	12070	10195	8749	7645	6770	5987
2 Ma Hs Mf - O	52394	23724	17043	13395	11227	9566	8283	7311	6558	5915
3 Ma Hs Lf - O	41845	20167	14648	11598	9709	8309	7244	6445	5857	5313
4 Ma Ms Hf - O	24831	12592	9185	7303	6080	5217	4527	3986	3570	3205
5 Ma Ms Mf - O	22310	11454	8400	6660	5574	4820	4190	3732	3376	3065
6 Ma Ms Lf - O	18515	9591	7130	5699	4759	4097	3598	3225	2937	2685
7 Ma Ls Hf - O	10496	5590	4154	3325	2795	2411	2137	1925	1733	1571
8 Ma Ls Mf - O	9353	5049	3770	3026	2546	2201	1958	1770	1604	1466
9 Ma Ls Lf - O	7681	4213	3197	2587	2187	1888	1694	1523	1389	1272
2 Ba Hs Hf - O	74101	30978	22165	17383	14423	12210	10625	9308	8323	7434
3 Ba Hs Mf - O	67659	28526	20482	16082	13352	11370	9953	8829	7951	7179
4 Ba Hs Lf - O	55493	24240	17471	13806	11547	9848	8584	7704	6973	6358
5 Ba Ms Hf - O	32224	15257	11041	8693	7305	6219	5429	4824	4366	3958
6 Ba Ms Mf - O	29779	13605	10021	7951	6650	5728	5036	4494	4089	3728
7 Ba Ms Lf - O	25113	11533	8590	6875	5857	5004	4415	3966	3600	3290
8 Ba Ls Hf - O	13611	6880	5051	4027	3376	2904	2583	2309	2100	1908
9 Ba Ls Mf - O	12293	6275	4665	3722	3119	2676	2393	2139	1949	1781
10 Ba Ls Lf - O	10379	5222	3922	3161	2685	2352	2096	1907	1745	1603

Yr 1 BO	Yr 2 BO	Yr 3 BO	Yr 4 BO	Yr 5 BO	Yr 6 BO	Yr 7 BO	Yr 8 BO	Yr 9 BO	Yr 10 BO
12173	4606	17535	13952	8693	8855	8299	4593	1963	3008

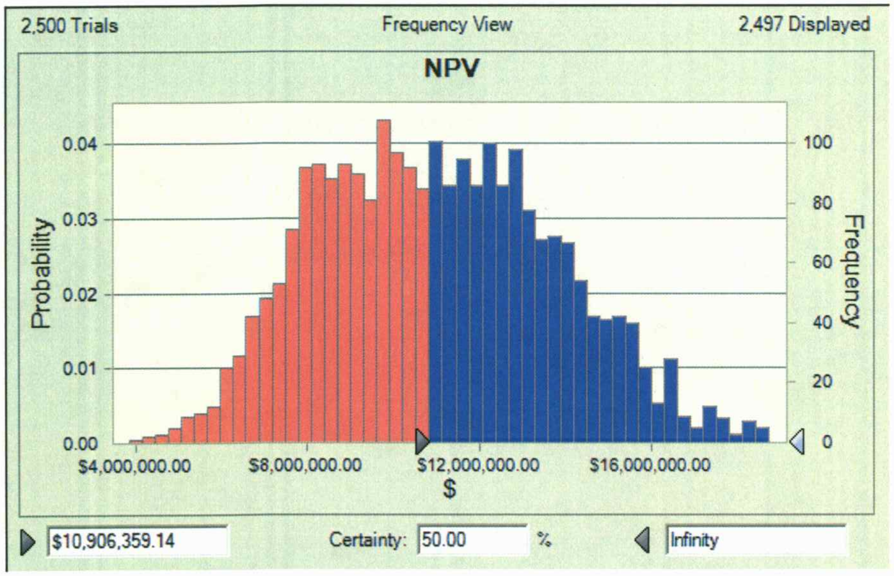
Yr No	1	2	3	4	5	6	7	8	9	10
Drilling Expense	$ 592,468.33	0	0	0	0	0	0	0	0	0
Operating Expense	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65	$ 34,216.65
Income	$ 781,606.83	$ 498,621.11	$ 1,994,466.33	$ 1,579,946.45	$ 971,538.38	$ 990,193.36	$ 925,950.15	$ 497,157.00	$ 192,879.60	$ 313,786.43
Dis Csh Flow 1	$ 781,606.83	$ 473,574.53	$ 1,799,127.94	$ 1,353,615.68	$ 790,552.36	$ 765,258.84	$ 679,662.99	$ 346,590.97	$ 127,710.81	$ 197,330.03

NPV	$ 7,315,030.98

	Mid	Low	High
Drilling & Comp			
$ 592,468	$600,000	$540,000	$660,000
Operating Expenses/Yr			
$ 34,217	$ 33,000	$ 29,700	$ 36,300
Oil Price			
$ 115.69	$ 110	$ 90	$ 140
Discount Rate %			
5.3	5	4	6

Figure 29: Uncertainty analysis of net-present-value (NPV) for Champlin Aldrich 4.

10 yr NPV @ 50% confidence – Minimum of $10.9 million



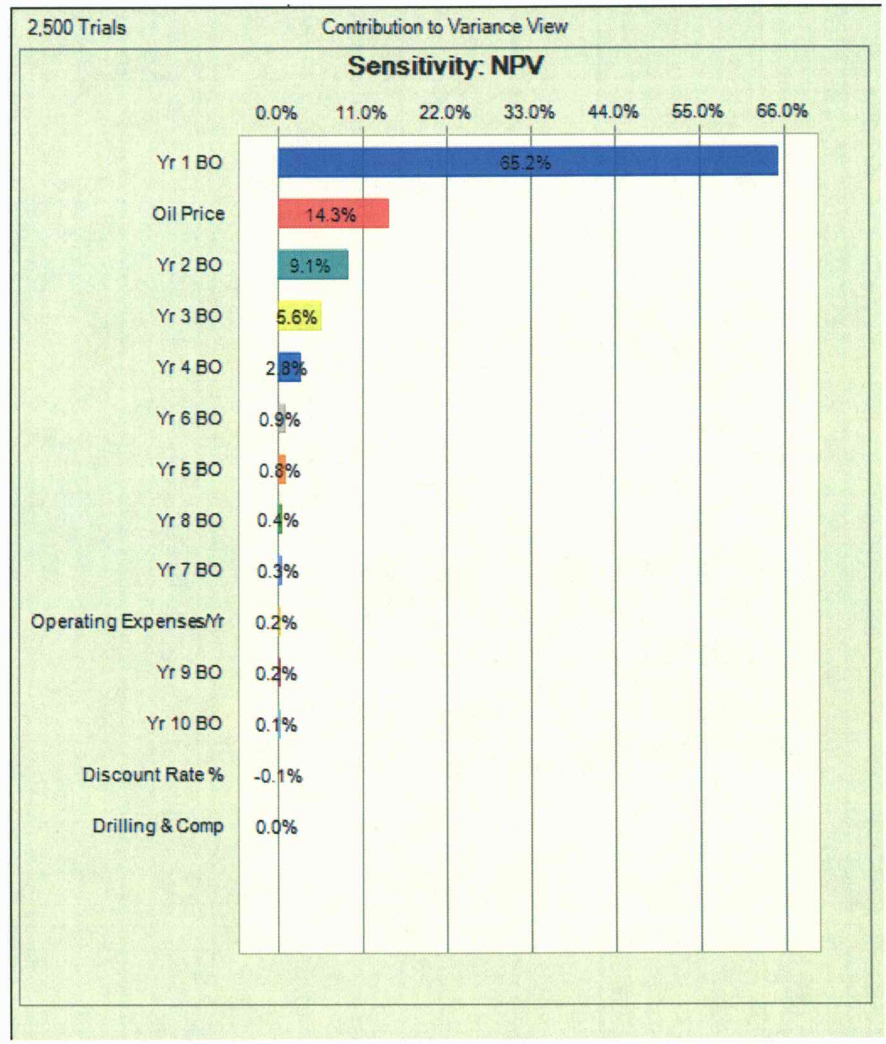


Figure 30: NPV calculation at 50% confidence and tornado chart to identify drivers for calculated NPV of Champlin Aldrich 4.

10 yr NPV @ 75% Confidence – Minimum of $8.8 million

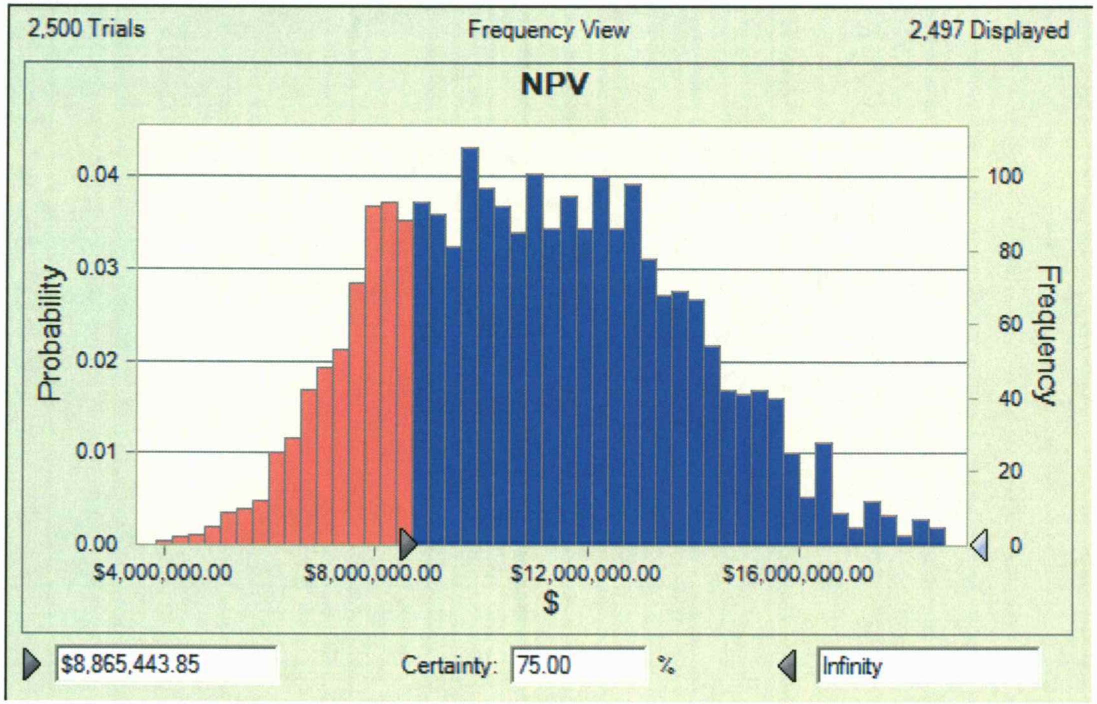


Figure 31: NPV calculation at 75% confidence for Champlin Aldrich 4.