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Reservoir Management Applications
to Oil Reservoirs

Final Report Prepared for
Nance Petroleum and
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1 Conclusions of the study

- Nisku original oil-in-place (OOIP) is estimated to be 18,000,000 bbl.
- Four to six additional wells at the current spacing will produce a total of 600,000 bbl of primary oil during the next five years. If more than six wells are completed in the Nisku formation, pressure maintenance will be required.
- Ultimate primary recovery will be approximately 4% of the OOIP.
- Reduced well spacing results in income acceleration, but no increase in reserves.
- Key reservoir properties (thickness, porosity, permeability, and water saturation) required for characterization were initially estimated by correlating the reservoir structure provided by 3-D seismic with the openhole logs.
- The seismic-log correlations were refined using a black oil model to automatically match the Crusch 1-10 production history and the reservoir pressure history at three different reservoir locations.
- Coupling structure and simulation to estimate key reservoir parameters has not been reported in the technical literature.
- The reservoir description from the history match was used to forecast various reservoir management scenarios.

2 Background

Winnipegosis and Red River oil production in the Bainville North Field in Roosevelt County, Montana (Figure 1) began in 1979. The Red River is at 12,500 ft and one well is completed in the Nisku formation at 10,200 ft. This well produced 125,000 bbl from the Nisku during its first 41 months (Figure 2). Since operating conditions inhibit dual completions and Nisku wells cost \$900,000, the need for a Nisku development plan is apparent. The size of the reservoir and optimum well density are the key unknowns.

Recognizing the need for additional Nisku data, a 5000 acre 3-D seismic survey was processed and the results used to map the top of the Nisku. The reservoir thickness, porosity, and water saturation were known from the openhole logs at eight well

Figure 1: Regional map showing Nisku location.

Figure 2: Nisku production.

locations on an average of 320 acres spacing. The thickness of the thin pay limited the seismic information to areal extent of reservoir depth. Static reservoir pressure from drillstem test was available at two wells. Additional reservoir pressure data in the form of transient tests were available at two wells. Under Los Alamos National Laboratory Basic Ordering Agreement 9-XU3-0402J-1, the New Mexico Petroleum Recovery Research Center (PRRC) characterized the Nisku to develop a reservoir management plan. Nance Petroleum provided all available field and laboratory data for characterizing the Nisku formation. Due to sparse well coverage, and the lack of producing wells, the PRRC had to develop a new reservoir description approach to reach an acceptable characterization of the entire reservoir. This new approach relies on the simultaneous use of 3-D seismic and reservoir simulation to estimate key reservoir properties.

3 Correlating 3-D seismic to reservoir properties

Given the scarcity of measured Nisku data, the use of conventional reservoir mapping methods was not appropriate. However, the geologic events that led to the deposition of Nisku formation exhibit a trend. The northern part of the reservoir is thin with low porosity, low permeability, and high initial water saturation. From the wells logs, it is clear that porosity and permeability increase as the reservoir thickens toward the south. Conversely, the well logs suggest that water saturation decreases with thickness. These observations imply that a correlation may exist between the Nisku structure, as provided by 3-D seismic, and the key reservoir properties.

Using the newly re-processed 3-D seismic data, a structure map with 58 gridblocks in the east-west direction and the 70 gridblocks in the north-south direction was assembled. The total number of gridblocks is 4060. The size of each gridblock is 219.4 ft (1.1 ac.). The 3-D seismic data did not cover the entire map area, hence the values for the structure in the southeast and northwest corners were absent. To complete the entire grid, we used a mapping method that takes into account all the known values and their spatial distribution. The final structure is shown in Figure 3.

The two key parameters derived from Nisku depth are porosity, ϕ , and reservoir thickness, h . Based on the well log observations noted above, we speculated that the following correlations would be appropriate:

$$\phi = a_{\phi} \log[\log(d)] + b_{\phi} \quad (1)$$

Figure 3: Nisku Structure Map.

Well	Log porosity	Porosity from simulation	Log S_{wi}	S_{wi} from simulation
Crusch 1-10	22	11	9	31
Crusch 2-10X	20	12	10	30
Granley 4-15	13	12	24	27
Bessie 1-10	13	12	19	30
Granley 1-10	11	11	35	31
Crusch 3-3	8	11	43	32
Crusch 2-3	7		61	
Crusch 1-3	7	12	34	28

Table 1: Porosity and water saturations at eight wells.

$$h = a_h \log[\log(d)] + b_h \quad (2)$$

where d is the depth of Nisku obtained from the 3-D seismic data. These correlations are considered for each gridblock of the entire map. In other words, knowing the depth at a specific location, one may estimate porosity and thickness at the same location.

Based on geologic reasons, we assume that the permeability, k , and initial water saturation, S_{wi} , are correlated to the estimated porosity ϕ in the following manner:

$$S_{wi} = a_s \log[\log(\phi)] + b_s S \quad (3)$$

$$k = 10^{a_k \phi - b_k} \quad (4)$$

Given these correlations, a reservoir model which provides the value of porosity, thickness, permeability, and initial water saturation, can be found given the structure of the Nisku. The log-derived values and the values derived from the assumed correlations for these key parameters are listed in Table 1.

Establishing the reservoir model consists of determining the eight parameters $a_\phi, a_h, a_k, a_s, b_\phi, b_h, b_k, b_s$ used in the porosity, thickness, saturation, and permeability correlations depicted in equations 1 to 4. A simple way of finding these parameters

is to use the data available at the wells. Unfortunately, the number of existing wells as well as their relatively similar depth does not allow a correct estimation of these eight parameters. Therefore, a new approach, which uses a black oil simulator and an automatic history matching algorithm, was used to estimate these eight unknown parameters.

4 Automatic History Matching

The history matching process consists of finding the reservoir model that honors the past performance of all the wells, in our case the Crusch 1-10 production history. In the petroleum industry, this time consuming process is usually performed by engineers who change reservoir properties such as permeability by hand in the simulator. After many changes, the history matching process is stopped when the project runs out of time or money. As a result, the final reservoir model may not honor the existing production and pressure history or laboratory data.

In this project, history matching is done automatically by a computer and the engineers devote most of their time to analyzing the results. In the case of the Bainville field, the history matching problem solved by the computer is the following:

Find the eight unknown parameters used in the four correlations, and the relative permeability curves, that will match the production and pressure of Crusch 1-10

The computer starts with a set of initial values for all the unknown parameters and creates a reservoir model. This initial reservoir model is fed to a black oil simulator to predict the production and pressure of Crusch 1-10. As expected, the initial reservoir model does not fit the production history of Crusch 1-10. The mismatch between the actual and simulated production and pressure is used to compute the error E :

$$E = \omega_i^{gas} \sum_{j=months} (GR_j^s - GR_j^f)^2 + \omega_i^{water} \sum_{j=months} (WR_j^s - WR_j^f)^2 + \omega_i^{pressure} \sum_{j=months} (P_j^s - P_j^f)^2 \quad (5)$$

where GR and WR are monthly gas and water rates for Crusch 1-10 respectively, P is the pressure, and ω are the weighting factors. The superscript s corresponds to simulated values and f corresponds to the field data. At this stage, the computer will adjust and change the values of some of the unknown parameters. These new values will lead to new maps of porosity, thickness, permeability, and initial water saturation

Well	Time	Measured pressure (psi)	Predicted pressure (psi)
Crusch 1-10	2/93	4618	4214
Crusch 2-10	7/94	3680	4590
Granley 4-15	6/95	3795	4567
Crusch 1-10	9/95	3920	3964

Table 2: Comparison of measured and simulated pressures.

that can be tested with the black oil simulator. After running the simulator for 41 months of available production, a new error E_1 that measures the mismatch between actual and simulated data can be computed for the new reservoir model. This new error E_1 is compared to the previous error obtained with the previous reservoir model. If the new error E_1 shows improvements over the previous error, then the current parameters tested will be considered as the best, and further adjustments will be made on them. On the other hand, if the new error E_1 is higher than the initial error, the current parameters will be discarded and a new set of parameters will be tested again. This iterative process continues until a good match of the field history is obtained.

5 History Matching Results

The results of the monthly gas and water rates history match for Crusch 1-10 are shown in Figure 4 and Figure 5 respectively. The mismatch of water production during the early months is due to the fact that the simulator does not account for completion fluids, and the produced water comprises the actual reservoir water production. There are also four available pressure data for the study. Table 2 shows the comparison between simulated and measured pressures.

From Table 2, it appears that the pressure of Crusch 1-10 is closely estimated, and there are large discrepancies for Crusch 2-10 and Granley 4-15. Before commenting on these discrepancies, it is important to notice in the DST of Granley 4-15 that radial flow was not reached as shown by the pressure derivative plot (Figure 6) which does not display a zero slope line. In other words, the pressure of 3795 psi is probably considerably underestimated. The simulated pressure is in the range of 4200-4500 psi. This observation also applies to the pressure measured one year earlier at Crusch 2-10,

Figure 4: Gas History Matching.

Figure 5: Water History Matching.

which was less than the pressure measured at Crusch 1-10 a year later. The pressure history as predicted by the simulator is shown in Figure 7 for Crusch 1-10 (continuous line), Crusch 2-10 (dashed line), and Granley 4-15 (semi-dashed line). Notice that Crusch 2-10 is physically closer than Granley 4-15 to Crusch 1-10, which explains the pressure of Crusch 2-10 being lower than Granley 4-15 pressure. In addition to the individual pressure at the wells, the calibrated reservoir model provides the pressure distribution throughout the entire reservoir at various periods. Figure 8 indicates the pressure distribution after 24 months of production. Pressure is further depleted after 36 months of production as seen in Figure 9. Finally, the pressure distribution as of September 1995 (41 months of production history) is illustrated in Figure 10. The pressure distribution maps indicate that the reservoir pressure is higher towards the southwest part of the Nisku reservoir.

The production and pressure history match supports the reservoir model, thus providing a good description of the reservoir properties. Furthermore, it appears that the size of the reservoir covers approximately the structure shown in Figure 3. The history matching process provided the unknown parameters for the four correlations shown in equations 1 to 4 which now become:

$$\phi = 8119.9 \log[\log(d)] - 17826.3 \quad (6)$$

$$h = 5285.4 \log[\log(d)] - 11609.5 \quad (7)$$

$$S_{wi} = -94 \log[\log(\phi)] + 114.4 \quad (8)$$

$$k = 10^{0.08\phi + 1.02} \quad (9)$$

In the four correlations, the depth d is given in ft , the porosity ϕ in % of pore volume, thickness h in ft , and permeability k in milli Darcy md . An immediate consequence of these correlations is the OOIP which is for the mapped reservoir grid:

$$OOIP = 17,895,327 \text{ bbl} \quad (10)$$

Granley State #4-15 * DST#3 * Rec #20223 @ 10150'

LOG-LOG PLOT

Test date.....: 6-29-95

Test time.....: 2nd Shutin

Figure 6: Granley 4-15 DST showing no radial flow reached.

Figure 7: Pressure history of Crusch 1-10, Granley 4-15, and Crusch 2-10.

Figure 8: Pressure Distribution after 24 months of production.

Figure 9: Pressure Distribution after 36 months of production.

Figure 10: Pressure Distribution in September 1995 (41 months of production).

Well	Depth	Porosity	Permeability	Thickness	Water saturation
Crusch 1-10	8070.7	11.3	84.4	1.36	31
Crusch 2-10X	8073	11.6	88.5	1.53	30.2
Granley 4-15	8080.7	12.4	103.6	2.08	27.5
Bessie 1-10	8073.6	11.65	89.6	1.57	30
Granley 1-10	8071.2	11.4	85.3	1.39	30.8
Crusch 3-3	8068.9	11.1	81.3	1.23	31.7
Crusch 1-3	8077.7	12.1	97.5	1.87	28.5

Table 3: Well properties.

Considering the fact that the exact size of the reservoir is approximate, this estimation may be considered as a maximum value. Using the correlations resulting from the history match, the gridblock properties of seven wells are shown in Table 3.

Notice in Table 3 that all the wells have approximately the equal depth. These depths are obtained from seismic data not from logs. In this range of depth, the porosity of the 219 ft gridblock is around 11%. This porosity is lower than that obtained from a core or estimated from a log because it represents a reservoir volume greater than that available in a core. Thus, heterogeneities that reduce the overall porosity are included in a 219 ft gridblock. The permeability appears to be in the 80 md range, and the initial water saturation around 30% at these reservoir depths.

In addition to the correlations, the history matching procedure led to the estimation of field relative permeability and capillary pressure curves. These curves are given in the analytic form expressed as

$$k_{rw} = 0.145 \left(\frac{S_w - 0.092}{1 - 0.25 - 0.092} \right)^{1.8} \quad (11)$$

$$k_{ro} = 0.94 \left(\frac{1 - 0.25 - S_w}{1 - 0.25 - 0.092} \right)^{2.4} \quad (12)$$

$$P_c = 28 \left(\frac{1 - 0.25 - S_w}{1 - 0.25 - 0.092} \right)^3 - 10 \quad (13)$$

$$k_{rog} = 0.1 \left(\frac{S_l - 0.5}{1 - 0.5 - 0.3} \right)^2 \quad (14)$$

$$k_{rg} = 0.05 \left(\frac{1 - 0.3 - S_l}{1 - 0.5 - 0.3} \right)^2 \quad (15)$$

$$P_{cg} = 8.8 \left(\frac{1 - 0.3 - S_l}{1 - 0.5 - 0.3} \right)^3 \quad (16)$$

As expected, the field relative permeability curves of oil and water are different from the ones measured in the laboratory. The difference is best seen with the water relative permeability curve where laboratory measurements indicate an endpoint of $k_{rw} = 0.5$. When using this value in the black oil simulator, the water production from Crusch 1-10 is 10 times higher than the actual field data. Therefore, to lower the simulated water production, the computer had to lower the water relative permeability endpoint to $k_{rw} = 0.145$. The difference in measurement scales is a common problem in reservoir simulation where it is necessary to find large scale reservoir properties such as permeability and relative permeability curves which are always measured at core scale.

Remember that these data have been obtained using only the production history of a single well and assuming a certain size of the reservoir. These results are subject to change if additional information becomes available. However, the magnitude of this estimation may not change drastically, and qualitatively speaking, they provide a good indication on reservoir properties. Hence, this reservoir model can be used to investigate reservoir management strategies.

6 Reservoir management

Using the calibrated reservoir model, we can forecast future performance of various reservoir management strategies. The forecasts will be presented in the following manner: semi-log plot showing the forecasted monthly oil rate versus time; a cartesian plot of monthly rate versus cumulative oil produced, and the pressure forecast at Crusch 1-10, Crusch 2-10, and Granley 4-15. Oil production from the different scenarios will be compared after 96 months of production from the Bainville Field.

6.1 Forecasting Crusch 1-10 Production

In this scenario, Crusch 1-10 is produced alone for 99 months, or 58 months after September 1995. Figure 11 shows the rapid decline of the production. After 96 months of production, the cumulative oil produced will reach $N_p = 229,427\text{bbl}$, which represents about 1.3% of the estimated OOIP. Notice in Figure 12 that the monthly rate will drop to 1000 bbl by year 2000 and the ultimate recovery will be in the range of 250,000 bbl of oil. The oil producing rate can be increased by drilling Nisku wells or re-completing in the Nisku interval.

6.2 Forecasting Crusch 1-10 and Crusch 2-10 production

This scenario assumes that Crusch 2-10X starts producing in November 1995, and Crusch 1-10 keeps producing for 99 months (mid year 2000). Figure 13 shows the monthly rate versus time for the total field production that includes Crusch 1-10 and Crusch 2-10. The monthly oil rate versus the cumulative production is illustrated in Figure 14. After 96 months of production, both wells cumulative production is estimated to be $N_p = 315,394\text{bbl}$, which represents 1.7% of OOIP. Therefore, producing Crusch 2-10 will lead to an increase in the primary recovery efficiency of about 0.4%. The pressure forecast for Crusch 1-10, Crusch 2-10, and Granley 4-15 is seen in Figure 15. Notice that Crusch 2-10 pressure (dashed line) drops to below 3800 psi and Crusch 1-10 pressure also drops by 100-200 psi which will cause a production drop at Crusch 1-10. On the other hand, Granley 4-15 pressure drop continues smoothly without a precipitous drop and remains in the 4000 psi range.

6.3 Production Forecast for 4 producing wells

In this scenario, we consider producing four Nisku wells shown in Figure 16. These wells are Crusch 1-10, Crusch 2-10, and two additional wells. Each new well starts producing after September 1995. The forecast of the monthly field rate versus time is shown in Figure 17. Ultimate recovery can be estimated from the field monthly rate versus cumulative oil produced from the four wells depicted in Figure 18. After 96 months of production, the field cumulative production is estimated to $N_p = 675,643\text{bbl}$, which represents about 3.8% of the OOIP. The pressure forecast at Crusch 1-10, Crusch 2-10, and Granley 4-15 is shown in Figure 19. Notice that Granley 4-15 pressure decline is faster than that observed in the previous scenario shown in Figure 15. In other words, adding only two wells significantly affects the total reservoir

Figure 11: Rate vs. Time Forecast for Crusch 1-10.

Figure 12: Rate vs. Cumulative Production for Crusch 1-10.

Figure 13: Rate vs. Time Forecast for Crusch 1-10 and Crusch 2-10.

Figure 14: Rate vs. Cumulative Production for Crusch 1-10 and Crusch 2-10.

Figure 15: Pressure Forecast when Crusch 1-10 and Crusch 2-10 are producing.

pressure, thus reducing rates at each of the wells.

6.4 Production forecast for six producing wells

In this scenario, the six wells shown in Figure 20 are producing from the Nisku formation. In addition to the Crusch 1-10 and Crusch 2-10, four other wells are completed in the Nisku. These wells are the Granley 4-15, Bessie 1-10, Granley 1-10, and Crusch 3-3. The additional wells begin producing after September 1995. This increase in well number significantly affects the reservoir pressure. As a result, the maximum initial monthly oil rate expected at the new wells will not exceed 1500 bbl. The forecast of the monthly oil rate versus time for the six wells is shown in Figure 21. Figure 22 forecasts the monthly rate versus field cumulative production. After 96 months of production, the cumulative oil produced is estimated to $N_p = 608,768\text{bbl}$, which is 66,875bbl less than what was estimated for the previous scenario of four wells. This reduction is due to the drastic reservoir pressure reduction induced by the additional production as illustrated in Figure 23.

6.5 Production forecast for thirteen producing wells

In this scenario 13 wells, as shown in Figure 24, are producing after September 1995. The wells represent the previous six plus seven additional new wells. If we assume that each of the wells starts producing in October 1995, the maximum initial monthly oil rate will not exceed 750bbl at each well due to reduced reservoir pressure. The rapid decline of the monthly field production versus time is seen in Figure 25. Figure 26 shows the monthly field rate versus the cumulative oil produced. After 96 months of production, this scenario would produce about $N_p = 572,618\text{bbl}$, which is less than the production obtained with six or four wells. The rapid decline of pressure at the three wells (Crusch 1-10, Crusch 2-10, and Granley 4-15) is depicted in Figure 27.

6.6 Production forecast for twenty producing wells

In this scenario, we consider the previous pattern of 13 wells and we reduce the spacing by half which led to the twenty wells shown in Figure 28. All the wells began producing in October 1995. Due to low reservoir pressure, the maximum monthly initial rate will not exceed 500bbl. The monthly field rate versus time is shown in Figure 29. The monthly oil rate versus field cumulative production is shown in Figure 30. After 96 months of production, the cumulative oil produced is estimated to $N_p = 591,782\text{bbl}$.

Figure 16: Location of the 4 producing wells.

Figure 17: Rate vs. Time Forecast for Crusch 1-10 and Crusch 2-10, and two other wells.

Figure 18: Rate vs. Cumulative Production for Crusch 1-10 and Crusch 2-10, and two other wells.

Figure 19: Pressure Forecast when Crusch 1-10, Crusch 2-10, and two other wells are producing.

Figure 20: Location of the 6 producing wells.

Figure 21: Rate vs. Time Forecast for 6 producing wells.

Figure 22: Rate vs. Cumulative Production for 6 producing wells.

Figure 23: Pressure Forecast when 6 wells are producing.

Figure 24: Location of the 13 producing wells.

Figure 25: Rate vs. Time Forecast for 13 producing wells.

Figure 26: Rate vs. Cumulative Production for 13 producing wells.

Figure 27: Pressure Forecast when 13 wells are producing.

This is an increase of 19,164*bbl* compared to the previous scenario with greater well spacing. This indicates that the current spacing can be reduced and may lead to a marginal increase of production. The economics depending on oil prices and drilling cost will indicate if this additional production justifies the additional wells.

In summary, this study demonstrates the use of a calibrated black oil model as a reservoir management tool. The scenarios examined in this study can be used as a guide to further development of the Bainville North Field Nisku reservoir. Enclosed with this report a diskette that contains the input files used to simulate the reservoir which can be used by Nance engineers to investigate other scenarios.

Figure 28: Location of the 20 producing wells.

Figure 29: Rate vs. Time Forecast for 20 producing wells.

Figure 30: Rate vs. Cumulative Production for 20 producing wells.