Land subsidence and well failure in the Belridge diatomite oil field, Kern county, California.
Part II. Applications

P. L. BONDOR & E. DE ROUFFIGNAC
Shell Development Co., Bellaire Technology Center, PO Box 481, Houston, Texas 77001-0481, USA

Abstract In the Diatomite reservoir, over 10 ft of subsidence and well failure rates averaging over 3% per year have occurred in some areas, resulting in several million dollars per year in well replacement and repair costs. An active effort, including both research and field operations, is underway to develop methods to understand the subsidence process and reduce its economic impact. This paper, labelled Part II, addresses the monitoring efforts and the use of finite element models to understand the effect of operating policy on subsidence and well failure. A companion paper labelled Part I (de Rouffignac & Bondor, 1995) discusses the experimental effort and the development of finite element models of the Diatomite.

UNITS

1 ft (foot) = 30.5 cm
1 in. = 2.54 cm
1 acre = 0.4047 ha

INTRODUCTION

The South Belridge Diatomite field is located approximately 50 miles west of Bakersfield in central California. Details of the formation comprising the reservoir have been described in the companion paper (de Rouffignac & Bondor, 1995). In brief, the reservoir is composed of a very thick, soft rock with a low Young’s modulus. This combination results in substantial compaction of the diatomite during fluid depletion; this compaction is believed to be the primary cause of the surface subsidence and well failures observed to date. Aggressive production by an offset operator in the mid-1980s resulted in the development of a bowl with a maximum subsidence of some 20 ft (6.1 m) in its centre; 20% of the operator’s wells failed annually over a four-year period, and large surface fissures developed on the edges of the bowl (Bowersox & Shore, 1990).

SUBSIDENCE MEASUREMENTS

An array of 200+ level survey monuments is in place throughout North, Middle and South Belridge fields. Field-wide measurements of subsidence have been carried out (at
least annually) since 1988. Figure 1 shows cumulative subsidence through the Spring, 1994 survey. Some areas of the field have subsided in excess of 10 ft from the 1942 zero level. Prior to the initiation of waterflooding operations on 1 ¼ acre (0.5 hectare) well spacing in the late 1980s, field subsidence in some areas was in excess of 18 inches (45 cm) per year. The waterflood project has been successful at substantially reducing subsidence; in some areas, annual data even show limited rebound. Figure 2 shows incremental subsidence between April 1993 and May 1994; in general, subsidence has been reduced to some 5 to 10 cm year$^{-1}$. While the monument surveys have been very valuable in monitoring the large-scale subsidence, the definition provided by the necessarily coarse array, and the limitations of instrument sensitivity, preclude use of the survey data to carry out a detailed examination of the relationship between individual well failures and subsidence.

MODELLING OF FIELD PROJECTS

Subsidence

The South Belridge field is currently developed with a pattern waterflood on 1 ¼ acre spacing, with a producer-to-injector ratio of 1/1. The field operating plan includes the
implementation of infill drilling to 5/8-acre spacing over the next 5 years, reducing anticipated waterflood project life. Oil recovery will be accelerated, and project economics significantly improved, if the development could utilize a 3/1 producer-to-injector ratio rather than the 1/1 ratio currently in place. However, a significant increase in well failure rate, increased surface subsidence, and potentially damaging surface fissures would adversely impact the project economics. The sensitivity of in-situ stresses and compaction/subsidence behaviour to producer/injector ratio was examined using simplified 2-D simulation models. These models, similar to the strip model described in the companion paper (de Rouffignac & Bondor, 1995), use a flat layer-cake grid structure and different process timing. No history match was attempted. The model was run to simulate 20 years of production from the field, including 14 years of history and 6 years of forecast.

The operating policy was modeled as follows: primary production on 2¼ acre spacing for 7 years. At 7 years, 1¼ acre infill wells are drilled and put on production, and the original 2½ acre wells are converted to water injection. At 15 years, 5/8 acre infill wells are drilled and put on production for an additional 5 years. Two scenarios are examined. In the first, the old 1¼ acre production wells are converted to injection with only the new wells remaining as producers (resulting in a 1/1 producer/injector ratio). In the second, both the 1¼ acre and 5/8 acre wells are retained as producers,
resulting in a 3/1 producer/injector ratio. Both policies are compared to the continuation of the present 1¼ acre project.

The results are shown in Figs 3 and 4. Figure 3 compares the maximum surface subsidence at the end of 20 years of production for the three cases. At 15 years, cumulative surface subsidence is 5.12 ft; after 5 additional years of production under 5/8-acre spacing, the 1/1 producer/injector ratio results in 1.03 ft, and the 3/1 ratio 3.15 ft, of additional subsidence. By comparison, continuation of the 1¼ acre flood results in just 0.6 ft of additional subsidence. As one would expect, the effect is most marked immediately after the infill wells are put on production; in the first year, the 3/1 pattern subsides 1.22 ft compared to 0.4 ft for the 1/1 pattern. Figure 4 shows the surface contour over the model at 7 years (installation of 1¼ acre waterflood), 15 years (installation of 5/8-acre waterflood) and 20 years, for the three cases considered. Not only the subsidence, but also the surface slope, is steepest for the 3/1 pattern case.

Fig. 3 Subsidence sensitivity to 5/8 acre infill scenario for Section 33.

Fig. 4 Subsidence sensitivity: 1¼ acre vs. 5/8 acre waterflood infill scenarios.
Well failure

At present, we have no quantitative causal relationship established between surface subsidence and well failure. Qualitatively, however, we anticipate greater well failure rates in areas of high subsidence rate. Also, many observed well failures are doglegs, which suggest a shear mechanism. High shear strains are calculated in situ beneath the areas of highest surface gradient. The models developed can be used to explore the development of strains in the reservoir as a result of operating policies. Shear strain development may be related to doglegs, while vertical strains could lead to buckling failures. Figures 5(a) and (b) depict the shear strain distribution in the two weakest layers (the lower Tulare and the uppermost layer (G) of the Diatomite) for the first two years of the 5/8 acre infill project. There is a substantial increase in shear strain over time in the 3/1, compared to the 1/1, development policy. In addition, the results show increased shear strain differences at different locations in the model, specifically on different sides of a well. Figures 6(a) and (b) depict the vertical strain distribution in the

(a) 

Lower Tulare Shear Strain

(b) 

Diatomite G Shear Strain

Fig. 5 Shear strain distribution in (a) the lower tulare layer during the first two years of waterflood on 5/8 acre spacing, and (b) the Diatomite G layer during the first two years of waterflood on 5/8 acre spacing.
models. These data also show substantially higher strains in the 3/1 policy than in the 1/1 case. The vertical strains may be used to calculate differential compaction within the formation as a function of time, and thus forecast differential compaction rates under different operating policies.

FIELD MONITORING

Permanent tiltmeter arrays

The implementation of the 5/8 acre waterflood will take place in stages, at roughly 50 acres per year through the end of the decade. In 1994, two 25-acre areas have been converted; in one (in Section 33), the flood will be installed with a 3/1 producer-to-injector ratio, in the other (in Section 34) a 1/1 producer-to-injector ratio will be used. To determine the influence of operating policy on subsidence, arrays of tiltmeters were installed in both areas to provide a more detailed, more frequent monitoring of field subsidence. Figure 7 shows the (approximate) locations of the tiltmeters. In Section 33, twenty tiltmeters were installed in February and March 1994. In Section 34, twelve
Tiltmeters were installed in August 1994. It is intended to use the tiltmeter arrays to monitor the surface subsidence of the two projects over the next two years, and obtain a direct comparison of the behaviour of the 1/1 versus the 3/1 ratios.

Figures 8, 9 and 10 illustrate monthly data obtained by the tiltmeter array in Section 33. In late June through July, the new 5/8 acre infill wells were put on production. The
Fig. 9 Surface subsidence contours (units: inches) from Section 33 tiltmeter array, 1-31 August 1994.

Fig. 10 Surface subsidence contours (units: inches) from Section 33 tiltmeter array, 1-31 December 1994.

flush production resulting appears to be reflected in the subsidence bowl seen in Fig. 8 (July 1995), as wells in the central and northern part of the project come on stream in early to mid-July. The wells in the southern part of the project came on stream in late
Land subsidence and well failure in the Belridge Diatomite Oil Field. Part II

July; and the shift in maximum subsidence to the south seen in Fig. 9 (August 1995) reflects their flush production. September's data are very similar to August; by December, flush production from new wells no longer is apparent, and the contours shown in Fig. 10 appear to be more closely aligned with the balance of injection and production occurring in localized areas of the field. The December data, however, seem to confirm that the 3/1 producer-injector ratio is resulting in a higher average subsidence than has been seen in the 1-1/4 acre waterflood.

The tiltmeter array to date has given encouraging results. Twenty tiltmeters have been in place for one year (as of March 1995), with no failures, and have provided reliable data throughout. As the Section 34 project, with a 1/1 producer-injector ratio, comes on stream, it is expected that data from that tiltmeter array will provide similar information to allow comparison between the effect of different operating policies. In addition, results to date (Wright et al., 1995) indicate that the surface subsidence, as measured by the tiltmeter array, can provide information regarding the changing stress state in the reservoir. Such information can be used to predict the direction of hydraulic fractures to be induced in new infill wells, allowing optimum placement of the new well.

Compaction monitoring

As shown above, the model provides data on the compaction of individual geological layers within the reservoir. To verify these data, two observation wells (one in the Section 33 project, one in the Section 34 project) will have 16 radioactive bullets permanently installed at intervals throughout the productive zone; the vertical location of these markers will be surveyed quarterly to detect differential compaction within the reservoir. In addition, the observation wells will have 20 pressure transducers installed at various depths throughout the productive zone, to allow comparison between simulation pressures and field data.

Well damage monitoring

Our understanding of the onset of well damage and failure, and timing of occurrence, is very low. Well damage and failure are discovered only in the course of normal operations (pump changes, etc.) when it is found that equipment cannot be run to (or removed from) operating depths in the well. Whether damage is gradual or episodic is not known. To answer these questions, a regular well survey program will be carried out on 15 selected wells in each of the two projects. Each well will be surveyed a minimum of once a year, and deviations (well deflection, casing diameter and eccentricity, degree of corrosion) will be measured. By comparing survey data with predicted reservoir strain state, it is hoped that model, survey and production/injection data can be integrated to give a clear understanding of the mechanisms operating in the field to cause well failure.

CONCLUSION

Simulation models can be applied to the prediction of both subsidence and well failures. Two-dimensional simulations have been applied to examine the impact of different
operating policies on subsidence, and to generate predictions of in-situ strains caused by those policies. Two field projects using different operating policies have been instrumented to monitor subsidence, compaction and well damage. The installation of long-term tiltmeter arrays has been shown to be a reliable way to obtain detailed subsidence data with precision and resolution far exceeding that possible from level monument surveys. The data from these arrays can be used to study the details of the response of the reservoir and overburden to injection and production.

Acknowledgements The installation and monitoring of the tiltmeter arrays has been carried out by Pinnacle Technologies, Inc., of San Francisco, California. The insight obtained from discussions with Chris Wright and Rob Conant of Pinnacle is gratefully acknowledged.

REFERENCES

