Geological reasons causing rapid rate decline. A case study of Field T, Russia.

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Abstract. The paper introduces the complex approach to determining possible geological reasons causing rate decline in the wells of Field T, Russia. Therefore, possible geological reasons are sequentially considered and were divided into three main groups: 1) rate decline due to poorer reservoir quality; 2) rate decline due to facies lateral substitution; 3) rate decline due to active fault tectonics. The most appropriate facies models were constructed on the basis of all available data. Besides, in this study, core, well logging, seismic and well test data were integrated for the fullest reservoir characterization. The core from several recently drilled wells was described in detail to determine clue features. Further, seismic data were interpreted: structural interpretation, including faults and attribute analysis, was implemented. Appropriate electrofacies models were chosen as well. At the final stage, all previously-mentioned data were integrated with appropriate facies model construction. However, as it turned out later, the facies model was not the key factor affecting the rapid decline that appeared in some wells. It is suggested that very proximal faults can be a possible explanation. To confirm this suggestion, well test data were additionally used and both analytical and numerical methods were applied to show the consistency of this theory.

1. Introduction

Field T is at the end of exploration and at the beginning of production drilling phases. Several wells (13, 141, 142, 143) have recently been drilled in the western part of the field according to the appraisal drilling program. No special risks were expected in this part of the field. However, the wells experienced a liquid rate decline soon after the production start. Production in well 141 fell from 120 m\textsuperscript{3}/day to 60 m\textsuperscript{3}/day within several months (figure 1). In well 142, the rapid rate decline from 150 to 25 m\textsuperscript{3}/day occurred within just 3 days. The situation in well 143 is very similar to that in well 142. All wells due to the poor reservoir quality were hydraulically fractured before or soon after the production start. The geometry of fractures in the wells under consideration is quite similar and all technological risks are believed to be significantly reduced. Therefore, the true reason for the decline is still unknown and possible geological reasons affecting well production should be analyzed. The correct determination of the reasons is of great applied significance, since the result will have a direct influence on the further drilling program for Field T.
2. General information
Field T is located in the western part of Orenburg Region and is known as the largest discovery made in this area in recent years (2005). Thus, a 3D seismic survey was conducted and 18 wells were drilled within the license area (figure 2).

The terrigenous Kolgan formation of the Late Frasnian age is the principal reservoir containing \(~85\)% of the overall STOIIP. There are three main units within the Kolgan formation: 1) upper terrigenous unit; 2) intermediate argillaceous-calcareous unit; and 3) lower terrigenous reservoir unit (figure 3). The lower terrigenous unit consists of a relatively thick (20-30 m) sandstone bed sometimes capped by shale. This sandstone bed is called Dkt-reservoir/unit. It is composed of two principal sandstone types interbedding each other: 1) fine-grained tight gray sandstone with frequent shale
laminae without oil shows; 2) massive-to-slightly cross-bedded fine-grained brown sandstone with oil stains. It is the unit for which a facies model was constructed.

![Figure 3. Well 1 section](image)

During core description, several characteristic features were marked and they are the clues to depositional environment determination. In well 12, part of the hummocky cross stratification was recognized to be the indicator of a lower shoreface (figure 4) [9]. In well 8, several indicators such as glauconite, flaser-to-wavy-structure (figure 5) and bidirectional structure were marked out all at once. Glauconite is intrinsic to shallow marine, whereas flaser-to-wavy and bidirectional structures are indicators of tidal activity [6]. During the core analysis, two ichnofacies were recognized: Skolithos (figure 6) and Cruziana (Teichichnus) (figure 7). Bioturbation by Skolithos linearis tubes is typical for the shoreface or tidal flat facies. The latter, Cruziana ichnofacies, in general, are intrinsic to a deeper, sublittoral zone and tidal flat as well [5].

![Figure 4. Part of HCS](image)
Figure 5. Flaser-to-wavy structure

Figure 6. Skolithos ichnofacies

Figure 7. Cruziana ichnofacies
A correlation profile in the SW-NE direction was constructed and it became clear that the Dkt reservoir is laterally extensive and shales out both in the north and in the south. In the north, a pinch-out line is suggested somewhere between wells 14 and 4. Since the Kolgan formation is abnormally radioactive, GR was used to separate it from under/overlying low radioactive carbonate rocks to mark out three distinct units within it. For the same reason, GR logs cannot be used to estimate the volume of shales. Thus, only an SP log was available for Vshale determination, which, however, has a lower resolution and gives less reliable results. At the next stage, well logs were used to estimate porosity in the Dkt-unit. There are three distinct well logging groups allowing porosity estimation: 1) neutron log; 2) density log; 3) acoustic log. It turned out that the acoustic log is matched better with core data than the others. The difference in poroperm properties was considered to be one of the possible reasons that influence the rate decline in the above-mentioned wells. Core plugs for measurements were sampled from wells 1, 2, 4, 11, 14, 222. Permeability for all these wells was estimated using the ‘core porosity – core permeability’ relationship (R2=0.65). Thus, there is a single poroperm relationship for all wells, and wells with similar porosity profiles have similar permeability profiles as well. This is the case for the ‘problem’ wells (figure 8). It is obvious that they are quite similar. Therefore, the rate decline in certain wells cannot be explained by the difference in reservoir properties.

![Figure 8. Comparison of porosity profiles in wells 220 and 141](image)

At the next stage, it was necessary to link lithotypes recognized in the core to petrophysical data. Porosity was chosen as a petrophysical property based on which the division into classes could be implemented. Core plugs were taken only from lithotypes 1 and 2, thus, it was meaningful to distinguish core plug data only in two classes (figure 9). The cut-off porosity value is 7.3% with which lithotypes distribution in the wells was implemented and QC’ed on the real core data (figure 10).
The electrofacies analysis is the most common sort of facies analysis due to the limited volume of core material. SP logs from 18 wells were divided into three distinct classes: 1) a barrier bar/island and associates with the central part of the suggested sand body [8]; 2) a dissected type curve indicating frequent interbedding of sandstones and shales and may correspond to a transition zone confined to the peripheral parts of the sand body [2]; 3) the 3rd type indicates the total absence of sand bodies within the cross-section and occurs in northern wells 4 and 6. This type of curve is typical for offshore environments. The selected electrofacies curves suggest a prograding barrier bar/island system, so a typical barrier island log curve was matched with a standard sedimentological model and real core observed in wells (figure 11) [10].
3. Seismic interpretation and attribute analysis

The area under study has recently been covered with a 3D seismic survey. Since the target Dkt-reservoir is within the lower terrigenous unit, only two reflectors were interpreted: 1) Dk1 – the lower terrigenous unit bottom; 2) Dk2 – the lower terrigenous unit top. It is worth noting that faults were interpreted as well and according to the seismic interpretation, wells 13/141/142/143 are located within an extensively faulted area. In the next step, an attribute analysis was performed. There were two principal problems to solve with this tool: 1) an attempt to recognize sand body boundaries, pinch-out line tracing in the north; 2) calculation of average petrophysical properties (e.g. porosity) using the ‘attribute-property’ correlation in wells. A set of different volume attributes was calculated (Relative acoustic impedance, instantaneous phase, etc.) and surface attributes using different algorithms (median, most of, etc.) were extracted from 3D attribute cubes. The analysis showed that the ‘RMS Amplitude’ and ‘Relative acoustic impedance’ attributes are the most useful ones and at least two different regions are clearly outlined 1) in the north/north-west; and 2) elongated in the west-eastern direction in the southern part of the area. It may be suggested that the boundary between these two regions is the above-mentioned pinch-out line of the Dkt-reservoir that was previously set somewhere between wells 14 and 4 that can now be easily traced. Finally, average porosity was calculated with the obtained porosity logs in wells and distributed within the investigated area with the multiple regression algorithm (figure 12). An average porosity map showed that the upper region is the region with quite low porosities – this is confirmed by dry wells 4 and 6. Thus, this is the area of reservoir absence.

Figure 11. SP log, sedimentary log and core data matching [10]
4. Facies model construction

The next logical step after the separate analysis of seismic, well logging and core data was their integration and design of a depositional environment concept being compliant with the whole data set. There is a list of 11 reasons derived from the previously analyzed data and that are in favor of the barrier bar/island depositional environment: 1) elongated shape of the sand body; 2) parallel to the supposed shoreline (regional geology); 3) appropriate size: 15,000x4,000x25 m [3]; 4) well-sorted quartzose sandstone; 5) coarsening upwards sequence; 6) shallow marine ichnofacies; 7) presence of glauconite [1]; 8) flaser-to-lenticular structure (tidal flat); 9) hummocky cross-stratification (HCS); 10) 70-90% of sandstone in the cross-section [4]; 11) appropriate electrofacies model. Thus, with the data available, it is logical to suggest a barrier bar/island depositional environment. Offshore, lower shoreface, upper shoreface/beach and tidal flat facies were recognized. In the lower part of all wells, a regression cycle is obvious, where offshore facies are consistently replaced by shoreface and beach facies. In the upper part, however, a transgression cycle is evident. The final part of depositional environment determination is the spatial facies distribution. Here, attribute and average porosity maps were taken as the basis. By integrating all data available, one can state that the 1st (central) zone of the sand body predominantly consists of middle/upper shoreface and beach facies, the 2nd (peripheral) zone contains lower shoreface/transition zone facies and finally, the 3rd zone is composed of offshore deposits (figure 13). Two ‘undefined’ zones were marked out. The reason for this is the ambiguousness in tracing boundaries between zones 2 and 3 using 3D raw seismic data and attribute cubes. The obtained facies model is confirmed by oil rates in the wells (figure 14). In this figure, an average porosity map derived earlier from the seismic attribute analysis is used as the background. Three distinct areas are recognized: 1) zone 1 where rates are relatively large, there are no lithotypes 3 or 4 in the wells and the average porosity value is higher than elsewhere (~8-9%). This is the central part of the supposed sand body; 2) transition zone where oil rates are significantly lower, lithotype 2 dominates and a remarkable amount of lithotypes 3 and 4 appears in the wells. This zone is peripheral and rims the central zone of the sand body from the north and the east. Average porosity is ~5-6%; and 3) offshore zone in the north that includes dry wells 4 and 6 and where average porosity is extremely low (2-4%). According to the obtained facies model and corresponding well logs, wells 13, 141, 142...
and 143 penetrate the same barrier bar/island deposits with similar poro/perm properties and oil-bearing thicknesses. Moreover, according to the admitted facies model, wells 142 and 143 are located in the more central part of the barrier island and thus, should have less clayey rocks, which is confirmed by well logs interpretation. Despite the fact all wells (13/141/142/143) penetrate very similar deposits, well 141 sustained a steady decline from ~120 m³/d liquid rate to ~50-60 m³/d within 3 months after the production start. At the same time, well 142 suffered a rapid liquid rate decline right after 2 days of production: from 150m³/d to 24 m³/d. The situation with well 143 is similar to that of well 142. Well 13 is also experiencing a steady rate decline. Thus, it can be concluded that facies distribution is not the key factor leading to the rate decline in wells 13, 141, 142, and 143 and other geological features should be considered.

Figure 13. Field T facies model
5. Fault analysis

Unfortunately, the facies model was unable to fully explain the anomalous behavior of wells 142 and 143. Thus, there is a question: what other geological reasons may cause this effect? As it has already been mentioned, structural seismic interpretation including faults interpretation was carefully conducted in the area of interest. It turned out that wells 13, 141, 142 and 143 are located in an extensively faulted region. One of the characteristic features of the faults is their proximity to the wells (figure 15). The faults drawn with a solid line are confidently recognized with a seismic survey, whereas the dashed-line faults are not so clear and require additional confirmation by other methods. As an additional justifying method, a well test was applied. In the absence of tests with sufficient duration, drawdown (DD) tests from wells 141 and 13 were analyzed. In both tests, the half slope line in the beginning (~100 hours) evidently indicates a fractured well [7]. Then, there is a short-lived derivative plateau (DP) from which average permeability and skin-factor were estimated – approximately 4 mD permeability in both wells and the integral skin-factor being about -5. In well 141, the deviation from DP occurs at the end of the test and was interpreted as a ‘double’ derivative plateau caused by the suggested single fault in the north of the well. In well 13, approximately in 250 hours from the beginning of the test, the strong influence of boundaries and neighboring working wells becomes apparent because the unit slope on the log-log plot is quite clear (figure 16).

Figure 14. Average porosity map with oil rates, lithotypes distribution in wells and three different zones
Figure 15. Fragment of the Dk1 structural map with faults

Figure 16. Log-log plot with interpretation (well 13)
6. Numerical model
The previous well test interpretation is analytical and it does not take into account various spatial distributions of faults, their shape, fracture geometry and its orientation, the influence of neighboring working wells, etc. Thus, during the next step, a numerical model was constructed to confirm that the interpreted faults could cause such a drastic rate/pressure decline. Three maps were used as the input data to the numerical model: 1) an average porosity map in reservoir rocks; 2) an effective thickness map; 3) an average permeability map in reservoir rocks (figure 17). Liquid rates, pressure history from neighboring wells, fracture geometry and its orientation were loaded as well. The main purpose of the numerical model construction is the justification of such a rate/pressure decline, demonstration of its possibility in general. The model was QC’ed in several ways: 1) it was matched with wells 141/142 pressure history; 2) Pi control in all wells (the initial pressures in wells calculated numerically should not differ from the real initial pressures) (figures 18, 19). The real initial pressures and those calculated numerically are shown in figure 20. The final match is adequate and the absolute error between the real and calculated initial pressures is not higher than 5 atm. In the numerical model, to match the pressure data, faults were assumed to be sealing.

![Figure 17. Input data and the resulting numerical model](image-url)
Figure 18. Pressure history matching, well 141

Figure 19. Pressure history matching, well 142

| Well no. | Date    | Pi [atm] | Pi (model) | Error [atm] |
|---------|---------|----------|------------|-------------|
| 220     | 06.09.11| 387      | 387        | 0           |
| 141     | 08.12.12| 342      | 346        | 4           |
| 142     | 15.04.13| 378      | 373        | 5           |
| 143     | 20.04.13| 370      | -          | -           |
| 13      | 21.06.13| 340      | 335        | 5           |

Figure 20. Observed and calculated initial pressures
12. Conclusions
In this paper, a complex approach using all data available to determine possible geological reasons for a liquid rate decline in wells was demonstrated. Possible geological reasons were determined: 1) poorer reservoir quality; 2) facies lateral substitution; 3) fault tectonics. Core, seismic, well logging data were sequentially analyzed and finally integrated and a conceptual barrier bar/island facies model was chosen as the most reasonable one. However, as it turned out later, it was unable to fully explain the problems, such as the rapid liquid rate/pressure decline that appeared in wells 13, 141, 142, 143, and the application of additional data was required. Fault tectonics was considered a possible explanation for such a rapid rate decline. To confirm this suggestion, well test data was additionally used and both analytical and numerical methods were applied to show the consistency of this theory. Therefore, it is important to consider an integrated approach in analyzing the possible geological reasons for problems in the field, since it provides the fullest reservoir characterization and determination of the key factors causing the challenge.

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