INTEGRATED WELLBORE STABILITY ANALYSIS FOR WELL TRAJECTORY OPTIMIZATION AND FIELD DEVELOPMENT: THE WEST KAZAKHSTAN FIELD

by

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science (Petroleum Engineering).

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Severe wellbore-stability issues such as stuck pipe, sidetracking of wells and incomplete pipe-conveyed-logging operations have been encountered during drilling horizontal wells in the West Kazakhstan Field. To contribute to solutions of these issues, an integrated wellbore-stability study was implemented to effectively plan the future drilling operations in the West Kazakhstan Field, to maximize the drilling margin for the future wells drilled, and to optimize the future field development. Typically, only a rock mechanics component for wellbore-stability analysis has been used to obtain wellbore-stability numerical models. In this study, however, the rock mechanical model was coupled with the mechanical stress, temperature alteration, shale-fluid physicochemical interaction, and the flow-induced stress using the Mohr-Coulomb and Mogi-Coulomb failure criteria. The problem diagnosis is a very important part of any wellbore-stability analysis. A special wellbore-stability problem-diagnostic scheme was first used to identify problematic horizons. The possible causes of the wellbore-stability issues were narrowed down. The well trajectory, drilling-fluid density, and types of water-based mud were confirmed to have a dominant impact on the occurrence of the wellbore-stability problems in West Kazakhstan Field. Dipole sonic, imaging, and sonic scanner logs were utilized to obtain in-situ stresses and formation properties. The strike-slip regime was identified in the study field. Pore pressure was predicted in the interest intervals within the West Kazakhstan Field utilizing the Eaton method with significant modifications of the Eaton’s compaction coefficients. The stochastic risk and sensitivity analysis was conducted to evaluate the sensitivity of the obtained input data on the study outcome. The Mogi-Coulomb formation failure criterion was found to be a better characterization of the brittle rock failure in the West Kazakhstan Field as utilization of the Mohr-Coulomb failure criterion resulted in overestimation of the wellbore collapse pressure, probably due to ignoring the strengthening effect of the intermediate principle stress. The results of this study could benefit the mitigation and/or prevention of wellbore-stability issues in the West Kazakhstan Field.
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ACKNOWLEDGEMENTS

This study would not have been possible without support of many people. First, I would like to thank my advisor, Dr. Azra Tutuncu, who has supported me throughout this thesis with guidance, knowledge, patience, caring, and excellent atmosphere for doing research. I would like to thank Dr. Ramona Graves for her guidance and support throughout and beyond this thesis. I would also thank Dr. William Fleckenstein for his support in this study and for allowing me to be a teaching assistant for his drilling and workover classes. Special thanks to Tom Bratton for both his industrial and scientific guidance.

I would like to thank my sponsor, “Bolashak” program, for the financial means to conduct this study. I would also like to thank the West Kazakhstan company for providing me the data for this study and the financial support.

I would also like to thank my colleagues, the graduate students from the Petroleum Engineering department, for their support and help.

Finally, I would like to thank my wife, Lunara Kadyrova, and my parents for their encouragement and love.
CHAPTER 1

INTRODUCTION

The West Kazakhstan Field is located on the northern margin of the Pre-Caspian Basin. The Pre-Caspian Basin covers an area of approximately 550,000 km$^2$ bordered to the south by the Russian Platform and Ural Mountains to the east.

The field has been currently in the exploration, field evaluation and reservoir characterization stages. Based on the information obtained from the vertical wildcat exploration wells, several horizontal and inclined wells have been drilled with a long-term production purpose. Most of those horizontal and inclined wells experienced severe wellbore-stability issues in drilling and completion stages while a few of these wells were completed without any wellbore-stability related challenges. The wellbore-stability analysis conducted by one of the service companies did not have a consistent agreement between the recommended mud weight (MW) and the field observations. The reason for the difference between the actual MW and recommended one could be interpreted as follows:

- the lack of provided information
- time restriction
- elastic assumption used for the formation instead of the realistic representation of the formation using an elasto-plastic rock behavior
- insufficient geological knowledge of the area

Later, a few horizontal sidetrack wells were drilled with severe wellbore-stability issues. The drilling progress charts for one of these wells are illustrated in Figures 1.1 and 1.2. Stuck pipe, unplanned sidetracks, incomplete well-logging data collection as well as completion operations, and excessive reaming have been encountered during drilling and completing the problematic horizontal sidetrack wells. It can be noticed from Figure 1.1 that the deviation between planned and actual curves starts at about 4800 m, and that is the kick-off point (KOP) in this case. Analysis of the shape of the cavings (see Figure 1.3) indicates the feasibility of reducing or even
avoiding wellbore breakouts with increasing MW. First, however, the exact collapse pressure should be constrained. Therefore, a rigorous wellbore-stability analysis needed to be conducted.

Figure 1.1 The drilling progress chart shows significant deviation from the planned drilling time due to the severe wellbore-stability issues encountered below KOP at 4800 m.

Figure 1.2 The cost increase associated with the unplanned wellbore-stability issues encountered below KOP at 4800 m.
1.1 Objectives of the Study

The purpose of this study is to determine the required drilling fluid density and to optimize the well trajectory for future drilling operations and field development in the West Kazakhstan Field. This has been done using an integrated borehole-stability analysis in conjunction with the offset-well data. The problem diagnostic workflow was applied to determine the problematic horizons and key parameters affecting wellbore-stability behavior. After the input data acquisition, the stress regime in the West Kazakhstan field was identified as the strike-slip regime. The obtained input data was used in the new numerical wellbore-stability model which is based on the conventional rock stress alteration (Kirsch) near the wellbore due to the placement of an arbitrarily inclined well and coupled with the following factors:

- fluid-rock and fluid-fluid chemical interactions
- stress changes due to the temperature alterations from the circulating drilling fluid
- stress alteration as a result of fluid flow into the formation

The derived wellbore-stability model has been calibrated using the drilling information, logging data and geological model. A history match of the observed field wellbore-stability cases with the coupled model was obtained. Then, the drilling programs for future wells in the study field
have been enhanced by designing optimized mud programs for any given wellbore trajectory. Moreover, based on the outcomes of this study, recommendations for the future field development have been provided.

Understanding the geological features of the field of study, sedimentation, and tectonic history is very critical in any wellbore-stability analysis to be conducted. The geology and tectonic history of the West Kazakhstan Field in the Pre-Caspian Basin are discussed in the subsequent sections. The stratigraphic column of the West Kazakhstan Field is illustrated in Figure 1.4.

1.2 Geologic Features of the West Kazakhstan Field

The West Kazakhstan Field is located at the northern edge of the Pre-Caspian Basin and surrounded in the east by the Ural Mountains and in the north by the Russian Platform. The area experienced a tectonic history of basement-related block faulting throughout the Paleozoic era. A ring of uplifts fringing the basin margin were positive features for much of the geological history. The West Kazakhstan Field discovery lies within this uplifted zone. These uplift features are believed to be long-lived structural highs. During the Paleozoic Age, sedimentation on these highs was dominated by shelf carbonates with reef development on the margins. The deeper inter-block areas predominantly were sourced with shales and deepwater carbonates. Much of the structural setting of the Carboniferous and Devonian intervals is therefore represented by broad, gentle structures with minor or no identifiable fracturing. By the Middle Permian period, the basin became partly closed, and the restricted marine influxes allowed for the accumulation of a thick Kungurian evaporate section in the basin and in the field of study as well (the West Kazakhstan company geologist, 2011, personal communication).

Rocks of Proterozoic crystalline substructure and Paleozoic, Mesozoic and Cenozoic age sediments were drilled in the West Kazakhstan Field to the maximum depth of 5385 m. A homogenous thickness of the Kungurian stage (more than 1200 m) divides sedimentary cover into three lithologic-structural systems within the bounds of the Pre-Caspian Basin. The pre-salt system consists of shallow-marine formation carbonate rocks of Devonian, Carboniferous and Lower Permian periods with thickness up to 2590 m forming a carbonate platform.
The middle part of the sedimentary cover, dated as the Kungurian stage of the Early Permian period, is presented by stratum of salt and anhydrites with a maximum thickness of 1278 m. The post-salt mega system, which consists of ages from the Late Permian to
Anthropogen and thickness up to 1640 m, consists of mainly clastic rocks with layers of carbonate and salt deposits.

The Frasnian Unconformity represents the main event in the pre-salt section. Below this unconformity, the prevalent trapping mechanism is tectonic (tilted fault blocks). Above the unconformity, the traps are mainly of a lithological type. The Middle Devonian-Lower Frasnian rocks were accumulated under various conditions: a) shallow shelf with predominantly carbonate sedimentation; b) relatively abyssal conditions with predominance of siliceous-argillaceous-carbonate rocks. The Middle Devonian-Upper Frasnian rocks are relatively abyssal siliceous-argillaceous-carbonate layers. The Upper Frasnian-Tournaisian rocks are in the condition of the northern Pre-Caspian margin. These rocks are accumulated in a fashion analogous with the Devonian formations, i.e., in both shallow and relatively abyssal conditions. Limestones and marls have accumulated in the shallow shelves, and there are also reef formations. Sedimentation took place in a suboxic environment (the West Kazakhstan company geologist, 2011, personal communication).

The Pre-Caspian Basin consists of four principle tectonic zones: the Northwest Monocline, Central Pre-Caspian Depression, North Caspian-Aktyubinsk Uplift Zone, and South-East Marginal Depression. The locations of these tectonic zones with respect to the depth of the Fransian Unconformity are illustrated in Figure 1.5. The West Kazakhstan Field is in the Northwest Monocline zone. The margin between the Northwest Monocline and Russian Platform is passive. Two theories of the Pre-Caspian Basin evolution exist (Zholtayev, 1989). First, in the beginning of the Middle Devonian epoch (the Middle Devonian), a platform existed in the Pre-Caspian Basin as a part of the East European Craton. However, the presence of step faults on the northern and western margins of the basin contradicts this theory. Opponents of another theory believe that, from the Early Paleozoic era (the Early Paleozoic), the basin was covered with an ocean with massive carbonates and reefs on the margin of this ocean. The West Kazakhstan Field is located on one of these carbonate highs.

Zholtayev (1989) and Lisovskiy et al. (1987) proposed the existence of two Paleozoic sub-basins in the Pre-Caspian zone, separated by the Astrakhan-Aktyubinsk zone. Each sub-basin experienced different subsidence history. Moreover, Zholtayev (1989) did not exclude the possibility of the existing several independent sedimentary basins within the Pre-Caspian Basin.
with different subsidence dynamics and geothermal heating. Brunet et al. (1999) described six stages of the Pre-Caspian Basin evaluation listed below based on tectonic subsidence analysis.

1. Subsidence during an active rifting phase in Riphean
2. Rifting in the Vendian-Ordovician
3. Significant subsidence in the Late Devonian
4. Acceleration of subsidence during the Late Carboniferous-Permian
5. Renewed rifting during the Triassic
6. Neo-tectonic subsidence resulting from the crustal down-bending in a generally compressional setting
1.2.1 Sedimentation of the Pre-Caspian Basin.

The Pre-Mesozoic era is represented with about 10 km of the sedimentary thickness (Volozh et al., 2009). Evaluation of sediments deposited in the Pre-Caspian Basin is not very well studied in the central parts of the basin due to the high sedimentation thickness. Moreover, thick Kungurian and Kazanian salt layers create challenges for clearly interpreting existing seismic data. Therefore, the uncertainty of the first sediments in the Pre-Caspian Basin creates some theories that are based on the data obtained from the drilling and seismic activities on the margins of the basin. On the other hand, data from deep exploration wells drilled in the West Kazakhstan Field shows that the first sediments accumulated in this part of the basin were during the Early Devonian.

According to Volozh et al. (2009), shallow water covered the Pre-Caspian Basin before and during the Devonian as shown in Figure 1.6. The West Kazakhstan Field is one of the highs in the North Monocline Uplift zones, that are considered to be the most permanent structures of the Pre-Caspian Basin, and the erosional Fransian unconformity between the Devonian and Carboniferous periods exists only in the central part of the West Kazakhstan Field. Later, during the Carboniferous period the water depth significantly increased in average to 1.5 km. Fluctuation of the paleo-water depth in the West Kazakhstan Field could be the reason for the sequence of thick carbonates with relatively thin layers of shale. It should be noted that these layers of shale are the source of wellbore-stability issues encountered in the study field. During the Permian the second east-west oriented compressional tectonic activities created the uplifts near the Uralian belts. Also, at the same period, the Ustyurt microcontinent arrived in the south-east which created barriers with the open ocean on the south and south-east part of the basin. These collisions resulted in the final isolation of the Pre-Caspian Basin. A shortage of water supply was a reason for thick salt accumulation during the Kungurian and Kazanian stages as illustrated in Figure 1.7.

1.2.2 Tectonics of the Pre-Caspian and Bordering Areas

The Uralide orogen, oriented north-south, was formed due to the collision of the Siberian-Kazakhian terranes and the East European Craton. The collision occurred in the Late
Figure 1.6  Reconstruction of the Pre-Caspian Basin evaluation along the north-south cross section (Volozh et al., 2003).
Paleozoic (Late Devonian/Early Carboniferous) and created geologic highs along the East European Craton (Hetzel and Glodny, 2001). The first collision resulted in the north-west oriented trusting of Pre-Caspian Basin sediments. This fault orientation is very close to the observed Devonian faults in the study field (120 degrees from the North).

The second collision occurred in the Early Permian and resulted in east-west directed forces that had given rise to the east-west oriented faults in both the Devonian and Carboniferous-Permian deposits in the field of study. The fault orientations, based on the Hetzel and Glodny study, are different from the present orientation of the maximum horizontal stress (SHmax) direction (155 degrees from the North) in the West Kazakhstan Field. This difference in the stress orientations might be explained by the long-term occurrence of the basin subsidence. Another explanation can be the arrival of the Ustyurt microcontinent in the south-east of the basin.

The generation of the stress regime as a result of tectonic movements was described in the vicinity of the Southern Urals (Hetzel and Glodny, 2001), that is approximately 500 km from our study field. According to Hetzel and Glodny (2001), indentation started with a reverse fault
regime and became a strike-slip regime due to the increase of the vertical stress. The stress regime interpretation at the Southern Urals is close to the stress regime observation in the field of the study, which will be discussed in detail in the following sections.

The origin of the Uralian deformation is dated to be the Middle/Late Devonian (Gieses et al., 1999). There are two main periods of the shortening of the Uralian deformation: the Late Devonian and Late Carboniferous. According to Gieses et al. (1999), during the Middle and Late Carboniferous, a hiatus in the shortening of Uralian deformations occurred with the change of convergence direction. The third and final deformation process resulted in the closure of the Uralian Ocean and separation the Pre-Caspian area as an individual basin. The ages of these deformations are in good agreement with fault observations in the West Kazakhstan Field. Gieses et al. (1999) described the Riphean faults as normal faults. The termination of the Uralian deformation occurred at the end of Permian. As it was noted before, during the Permian, the Ustyurt microcontinent arrived in the southeast that created barriers with the open ocean on the south and south-east part of the basin.

Zholtayev (1989) explains the Fransian and Permian unconformities by tectonic activities in the Middle Devonian and Early Permian. These tectonic activities, due to the plate collisions, exposed some highs above water level and resulted in their erosion. The West Kazakhstan Field experienced the same age erosion evident from the observed lithological unconformities. In the period of the tectonic collision of the East European Platform and Ural-Tobol’sk microcontinent, the tectonic forces were oriented east-west. Significant tectonic activation occurred during the Famennian and Tournaisian stages. It might be an explanation for the Tournaisian faults observed in the field of study. As the end of the Tournaisian, the north movement of the Karabogaz microplate took place (Zholtayev, 1989). It might be the explanation of the current SHmax direction in the field of study (155 degrees from the true North).

Natal’in and Sengor (2005) summarized the tectonic synthesis of the Scythian and Turan Platforms. These platforms are located at the southern margin of the Pre-Caspian Basin as shown in Figure 1.8. Here is a high probability that the tectonic motions of these two platforms had a high impact on the stress orientations in the field of study and in most parts of the Pre-Caspian Basin. In fact, strike-slip motions of these platforms and the orientation of the shortening (150-
160 degrees from the true North), as it is illustrated in Figure 1.9, are in good agreement with some fault orientations and the direction of SHmax in the West Kazakhstan Field.

Figure 1.8 Tectonic positions of the Turan and Scythian platforms (Natal’ in and Sengor, 2005). The tectonic force direction of these two platforms is in good agreement with the fault orientations in the field of study.

Figure 1.9 Paleotectonic reconstructions of tectonic movements for the Early Permian-Triassic age (Natal’ in and Sengor, 2005). The direction of the Scytho-Turanian collision is in good agreement with the current horizontal principle stress orientations.
1.3 Data Utilization for wellbore-stability analysis

Utilization of available data for wellbore-stability analysis is discussed in the following subsections.

1.3.1 Well logging data

Well logging data is available for several wells drilled in the study field. Well log data has been used to build petrophysical models for each inter-fault section of the field. In addition, FMI and Sonic Scanner data collected in a limited number of wells has been utilized to obtain in-situ stress magnitudes as well as stress orientations and to estimate the level of stress anisotropy. Moreover, the image logs were used to correlate the drilling data and observed borehole conditions to identify the specific intervals causing wellbore-stability issues. MDT and RFT data was utilized to calibrate pore pressure prediction models for the field of study.

1.3.2 Daily well site reports

Daily well site reports can be a helpful source to identify unstable intervals when well-log data is not available.

1.3.3 Daily drilling reports

Daily drilling reports have been utilized to identify the reasons for the rock failure in the vicinity of the wellbore. Observed challenges during the drilling process such as string overpulls, landings, sloughing and mud losses have been correlated with caliper and well image log data to identify the unstable intervals. The time effect associated with the chemical interactions was indirectly implied from the drilling performance and the caliper data.

1.3.4 Daily mud reports

Daily mud reports were utilized to compare the chemical compositions of the mud with the formation fluid and grain compositions. This analysis is helpful for the modeling of the chemical fluid-fluid and fluid-rock interactions during the drilling phase. Preliminary diagnostics imply that potassium chloride provides better wellbore stability in the field compared to the aluminum-resin complex. In addition, the daily mud reports provided an indirect-clue to the hole cleaning issues during drilling of the directional wells.
1.3.5 Daily mud logging reports

Daily mud logging reports have been used to acquire input data for petrophysical modeling. Also, mud logging reports have been utilized for identifying the high pore pressure zones in source shale intervals that were critical in correlating the suitable pore pressure prediction models. The size and shape of cuttings have been used to verify the active wellbore-failure mechanism taking place in the field to make a critical decision about whether to increase mud weight or to hold it at the same level. Moreover, gas show readings were used to pinpoint the pore pressure for the hydrocarbon-saturated shale intervals.

1.3.6 Primary cementing reports

An indirect utilization of cementing reports is one of the correlating factors for predicting a maximum allowable ECD to drill a particular section.

1.3.7 End-of-report and non-productive time analyses

End-of-report and non-productive time analyses were used to estimate an economical optimization of the drilling projects for the field development in the West Kazakhstan Field.

1.3.8 Geological Model

The existing geological model was improved by adding additional horizons to fulfill the interval 2700-5300 m with geomechanical input parameters. The improved geological model was also used to identify and visualize intervals creating wellbore-stability issues.
CHAPTER 2

PROBLEM DIAGNOSTICS

A problem-diagnostic methodology has been described and applied to two deviated wells in West Kazakhstan Field in order to narrow down and to identify the intervals and the factors affecting the wellbore stability in the West Kazakhstan Field. In the following sections, details of the problem diagnostic procedure we have used in this study are described.

2.1 Methodology

Several factors play key roles when it comes to analyzing wellbore-stability problems in a field during drilling and completion operations. Aadnoy and Looyeh, (2011), categorized the wellbore-stability issues as being caused by solid-fluid interactions, complex stress conditions, wellbore deviation and orientation, lack of appropriate drilling and operating practices, pressure alterations, and temperature change. In addition, the presence of faults, unconformities, stress alterations due to fluid flow into a formation and formation anisotropy can also impact on the formation to cause an unstable behavior. Typically, a combination of these factors influence failure at the wellbore.

The first step in diagnosing wellbore-stability problems is to confirm the existence of wellbore-stability issues. Then, the causes of possible rock failure can be narrowed down by excluding the key operational factors that did not create the problems. One of the techniques to narrow this search is to carry out a comparative study using the data analysis for wells drilled with and without wellbore-stability issues. If one of the factors was identical for both unstable and stable well cases, we can temporarily exclude the specific factor from the data processing with an assumption that this factor did not play a significant role in rock failure. At the end of this elimination process, only a limited number of parameters will be identified as contributing to the wellbore failure. Yet, unless a complex wellbore-stability dataset is available, the diagnostic analysis only helps in identifying possible factors without offering any solution.
One of the most powerful tools that can significantly help in identifying the major factors of a failure mechanism is an annular pressure gauge. The annular pressure gauge is located at the drilling bottom hole assembly (BHA) and provides the value of the annular pressure in terms of the equivalent static density (ESD) or equivalent circulation density (ECD). Analysis of ESD and ECD data acquired using this tool can help in determining poor drilling practices such as insufficient hole cleaning and/or high surge and swab pressures. Sometimes, only a stabilization of the ECD during drilling (e.g. improved hole cleaning) and tripping (e.g. control of swab and surge pressures) can result in solving wellbore-failure occurrences. However, a rigorous wellbore-stability analysis is always preferable to understand the influence of all key operational factors on wellbore-stability behavior. Unfortunately, no annular pressure gauge has been used yet in this field of our study. Therefore, it is difficult to state if excessive swab and surge pressures were the reasons for the wellbore failures. The use of an annular pressure gauge in the directional BHA during drilling wells in the future is under consideration and could be the subject of future research.

An illustration of the problem diagnostics workflow used in this study is presented in Figure 2.1. Each drilled horizon is analyzed for the existence of any wellbore-stability issues using the workflow shown in Figure 2.1. Then, the presence or absence of wellbore-stability incidents needs to be investigated based on several key operational parameters.

These parameters include:

- lithology
- drilling fluid type and weight used in the problematic intervals
- wellbore inclination and azimuth at the unstable horizon
- exposure time at the horizon
- hole cleaning performance

This diagnostic workflow can be used to investigate the preliminary reasons for the absence or existence of wellbore-stability incidents between two wells or two boreholes of the same well at the same horizon.

To quantify the severity of the issues, the workflow was linked to a “problem coding”.

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Numbers were assigned representing stability or instability of each interval. The code “0” represents the intervals where no wellbore-stability issues occurred. “1” shows the intervals with minor indirect wellbore-stability problems that were handled without pack-off and loss circulation incidents. Finally, the code “2” represents intervals where severe wellbore-stability issues happened, such as a stuck pipe, lost circulation, pipe-conveyed logging run restrictions and sidetracks.

The outcomes for the diagnostic analysis have been illustrated in 3-D view graphs to better characterize the reservoir. One example of such illustration is shown in Figure 2.2 where two “problem coded” wells are shown in the 3D view. Although both wells were drilled through the same horizons, the severe wellbore-stability issues were encountered while drilling the deviated well. However, no significant problems occurred during drilling the vertical well.
2.2 Case Study for Well G

A detailed investigation was carried out and well-logging data was carefully analyzed to diagnose the troubles encountered at Well G during the directional drilling from the measured depth (MD) of 4660 m (KOP) to the total measured depth (TMD) of 5942 m. The key operational data investigated for this analysis were the number of days spent on drilling this horizon, MD, total vertical depth (TVD), MW, ECD, borehole inclination and azimuth, lithology and operational comments. The integration of all the data made the diagnostic process faster and more flexible. The key aims of this diagnosis are to identify the formation(s) and lithologies that complicate drilling operations and to estimate the non-productive time (NPT) due to the wellbore stability if there is any NPT that can be eliminated. Also, the MW, ECD, wellbore inclination and azimuth have been evaluated to find the influence of these parameters on wellbore-stability issues during the directional drilling of wells in the field. Problem diagnostics were started from the kick-off point (KOP) depth for the problematic deviated Well G. The drilling progress charts for Well G are illustrated in Figures 1.1 and 1.2.

2.2.1 Eight and half inch Section

Well G was vertically drilled up to the KOP at 4660 m (TVD 4656 m) with an open hole size of 8 ½ inches. Then, the 8 ½ inch section was drilled to MD 4981 m with an inclination of
35.21 degrees and an azimuth of 295.8 degrees. The pipe conveyed logging (PCL) was not performed up to the planned depth due to landings at MD 4887 m. A 7 inch casing was run to MD 4981 m and cemented without any mud and/or cement losses.

This section of the well was drilled through the formations of the Upper Devonian period (Famennian stage, D3fm) and partially through the Middle Devonian. The Middle Devonian was represented in this sector of Well G by the Givetian (Vorobevski horizon, D2g(vb)) and Eifelian stages (Chernoyarovski horizon, D2ef(ch)). Due to the Frasnian unconformity, the Frasnian stage along with the Mullinski and Ardatovski horizons of the Givetian stage are missing in the stratigraphic column of this well.

2.2.1.1 Famennian stage

The Famennian stage was directionally drilled without any significant drilling issues from 4660 m to 4840 m (4656-4826 m TVD) with a maximum inclination of 34.55 degrees and 291.91 degrees azimuth at 4840 m. To analyze the reasons for the absence of wellbore-stability issues in the Famennian stage, some key operational data were collected. This data is listed in Table 2.1.

Analyzing the data from Table 2.1, we assumed that the reasons for the absence of any wellbore-stability challenges in the drilling performance in this section are the lithology and low inclination. Impacts of the azimuth and mud weights still need to be verified from the modeling part of this study.

Table 2.1  Key Operational Parameters Used for Drilling the Famennian Stage in the 8 1/2 inch Section of Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>4660 / 4845</td>
<td>4656 / 4830</td>
<td>LST 70% and DLT 30%</td>
<td>4.33 / 36</td>
<td>344 / 292</td>
<td>1.18 (9.85)</td>
<td>1.21 / 1.24 (10.1 / 10.34)</td>
<td>Perflex Polymer</td>
<td>Wiper trip at 4840m. Hole was in good condition</td>
</tr>
</tbody>
</table>
2.2.1.2 Vorobevski and Chernoyarovski horizons

The next stratigraphic stages drilled after the Famennian stage were the Givetian (Vorobevski horizon) and Eifelian stages (Chernoyarovski horizon). Severe wellbore-stability issues were experienced while drilling these two stratigraphic horizons. These included landings, overpulls, bit plugging, BHA stuck due to pack-off and lost in hole BHA. To determine intervals influenced by the wellbore-stability issues, a detailed analysis of the available well logs and drilling data was conducted. Again, the collected key operational data is presented in Tables 2.2 and 2.3.

Table 2.2   Key Operational Parameters Used for Drilling the Vorobevski Horizon in the 8 ½ inch Section (Before Pipe Got Stuck), Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azimuth deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>4845 / 4921</td>
<td>4830 / 4885</td>
<td>ARL and SLT 80 - 90% and LST 10 -20%</td>
<td>36 / 48</td>
<td>292</td>
<td>1.18 / 1.20 (9.85 / 10)</td>
<td>1.21 / 1.25 (10.1 / 10.43)</td>
<td>Perflex Polymer</td>
<td>Cavings up to 2% from 4889 m, impreg bit</td>
</tr>
</tbody>
</table>

Table 2.3   Key Operational Parameters Used for Drilling the Chernoyarovski Horizon in the 8 ½ inch Section (Before Pipe Got Stuck), Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azimuth deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>4921 / 4967</td>
<td>4885 / 4914</td>
<td>ARL and SLT 40-95% and LST 5-60%</td>
<td>47 / 53</td>
<td>292</td>
<td>1.20 / 1.25 (10 / 10.43)</td>
<td>1.27 (10.6)</td>
<td>Perflex Polymer</td>
<td>String pack-off, high SPP and TQ, impreg bit</td>
</tr>
</tbody>
</table>

The first indications of borehole-stability problems were observed at MD 4886 m (TVD 4861m). While picking up the bit off the bottom at this depth, stand pipe pressure (SPP) suddenly increased and activated pop-off valves of the mud pumps. The circulation was recommenced only after the second attempt, and an overpull of 5 tons was observed. After pumping the High Viscosity Pill (HVP), 2% cavings with 20% gas shows were observed on
shale shakers. As a reaction to these observations, the mud weight was increased from 1.18 g/cc (9.83 ppg) to 1.20 g/cc (10 ppg). Later, drilling was continued to MD 4934 m without any overpulls during connections. However, 1% of sharp angular cavings were still observed with HVP. After changing the impregnated bit and MWD to new ones and running them in the hole (RIH), the landing occurred at MD 4878 m and the impregnated bit got partially plugged with formation. This happened 56 m above the bottom which implies that the borehole was sloughing during the round trip to change the bit. During the run after cleaning the plugged bit, 6 tons of landing was observed at MD 4877 m, which is the same depth at which the bit got plugged. From this information it can assumed that both landings occurred at a sloughing interval. Since the first cavings were observed while drilling at MD 4889 m, the top of the sloughing interval is at 4877-4889 m. Since in this case landings and overpulls took place after tripping, ECD fluctuations due to swabbing and surging can be a rock failure mechanism.

Despite the hard reaming and sudden increase of the SPP and torque (TQ), drilling with the same mud weight of 1.20 g/cc (10 ppg) was continued to MD 4967 m where the string got packed-off. No circulation or string rotation was possible. Jarring did not bring positive results. As a result, the BHA was lost in the hole (LIH). The results of running Free Point Indication tools showed that the string was free at MD 4841 m and 84% free at 4891 m. Below 4891 m the string was gradually packed with the sloughed formation. To verify the top of the shale sloughing interval the caliper log was reviewed. The caliper log with gamma ray data is shown in Figure 2.3. As can be seen from this figure, the severe washouts up to 22 ¾ inches (the nominal hole size is 8 ½ inches) start at MD 4850 m, which is the top of the Vorobevski horizon. The gamma ray values from MD 4850 m (up to 75 gAPI) imply that the lithology at the interval 4850-4887 m is mainly composed of clay minerals. It might be that the Vorobevski horizon was a shale-sloughing source. Washouts in this interval was a reason for the PCL landing at MD 4887 m that caused incomplete well logging in the 8 ½ inch section of this well. Since there are no available well-log data for 8 ½ inch section below MD 4887 m, it is hard to evaluate the impact of the Chernoyarovski horizon on shale sloughing. However, the drilling reports were analyzed to obtain indirect information on the shale behavior in the Chernoyarovski horizon.

The kick-off cement plug was set on the top of LIH tools in order to sidetrack. The 8 ½ inch sidetrack borehole was drilled throughout the Vorobevski and Chernoyarovski horizons
to MD 4981 m (TVD 4938 m), which is the bottom of the Chernoyarovski horizon. Throughout drilling these two horizons, the well behaved similarly to the previous wellbore. However, the consequences of those wellbore-stability problems were different.

### 2.2.1.3 Vorobevski horizon (8 ½ inch sidetrack)

First indications of borehole-stability problems, such as landings and SPP increase, began at MD 4868 m (TVD 4849 m). This is 7 m above the TVD where the same indications occurred during drilling the previous borehole. Cavings were observed at shale shakers at the same TVD (4865 m) as in the previous hole. The amount of the cavings while drilling the sidetrack was up to 15% (0.5 - 1 cm length), which is higher than in the previous case (up to 2%). The reasons for the amount and size of cavings in this case could be the difference in the drill bit type and the higher mud weight used in the interval. Key operational data are shown in Tables 2.4 and 2.5. During drilling the previous borehole, when the BHA got stuck, the impregnated bit and turbine was utilized. The configuration and grinding mechanism of the used impregnated bit restricts passing of the cavings through narrow bit junk slot areas. Moreover, a turbine, with 1130 revolutions per minute (RPM) performance, together with the impregnated bit, works well in crushing relatively big pieces of caving fragments into smaller pieces. Overall, ground and
crushed cavings impacted on the mud rheology and packing tendency of the mud. On the other hand, a tri-cone bit was used in the second case (i.e. sidetrack case) when up to 15% of cavings were observed with 0.5-2 cm length. Due to the bigger junk slot area of the tri-cone bit, relatively larger cavings were transported to the surface, which is an obvious indication of acceptable hole cleaning performance. The higher mud weight 1.25–1.27 g/cc (10.43-10.6 ppg) could also reduce the rate of the shale sloughing and improve hole cleaning. Even with the severe landings, overpulls and torque increase, a drilling team was able to reach the bottom of the Chernoyarovski horizon and set the 7 inch casing. Probable reasons for avoiding pack-off incidents with shale sloughing were better hole cleaning and the effect of mud weight increase. Another reason can be a lower inclination (38 degrees) of this sidetracked wellbore than the inclination of the previous borehole (45-53 degrees).

Table 2.4  Key Operational Parameters Used for Drilling the Vorobevski Horizon in the 8 ½ inch Sidetracked Section, Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>4870 /4921</td>
<td>4850 /4895</td>
<td>ARL and SLT 80-90% and LST 10-20%</td>
<td>36 / 38.5</td>
<td>290 / 293</td>
<td>1.25 / 1.27 (10.43 / 10.6)</td>
<td>1.34 (11.18)</td>
<td>Per-Flex Poly-mer</td>
<td>Cavings up to 10-15% from 4883 m, tri-cone bit, WBI problems</td>
</tr>
</tbody>
</table>

Table 2.5  Key Operational Parameters Used for Drilling the Chernoyarovski Horizon in the 8 ½ inch Sidetracked Section, Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>4921 /4983</td>
<td>4895 /4939</td>
<td>ARL and SLT 35-60% and LST 40-65%</td>
<td>36</td>
<td>295 / 296</td>
<td>1.27 (10.6)</td>
<td>1.34 (11.18)</td>
<td>Per-Flex Poly-mer</td>
<td>Landing, overpull, TQ problems due to hole stability issues</td>
</tr>
</tbody>
</table>

It is important to notice that all hole issues, such as overpulls, landings, torque and SPP increase, occurred in the intervals that are represented by the Vorobevski horizon. This allowed
to infer, from the data in Tables 2.4 and 2.5, that the Chernoyarovski horizon was not a source of the wellbore-stability issues encountered during drilling the 8 ½ inch section of Well G. This assumption has been verified by modeling wellbore stability and analyzing the directionally drilled wells at the same stratigraphic stages and horizons as discussed in Chapter 5.

2.2.2 Six inch Section

A 6 inch section was drilled through the Middle Devonian period (Eifelian stage, D2ef) and the top of the Lower Devonian period (Emsian stage, D1em). The Eifelian stage was represented in this section of Well G by the Klinsovsko-Mosolovski and Biyski horizons. The key operational parameters used for drilling these stages and horizons are shown in Tables 2.6, 2.7 and 2.8.

2.2.2.1 Klinsovsko-Mosolovski horizon

Even though some key operational parameters used for drilling through the Klinsovsko-Mosolovski horizon (see Table 2.6) are not favorable for directional drilling, no significant wellbore-stability related issues were encountered during drilling this horizon. One of those unfavorable parameters is the wellbore inclination, which was in a range when hole cleaning is typically very challenging. Also, the relatively low mud weight, compared to the mud weight used for the previous sections, and the high shale-inhibitive KCl system justify our assumption that the key operational parameter in this section was the lithology. The lithology in this horizon is mostly limestone and dolomite dominated with a small inclusion of argillites. Since the dominating mineralogy is calcite, argillites did not cause significant drilling problems. On the other hand, in the intervals where the lithology is up to 60-100% argillites (TVD: 5015 m, 5028-5038 m), shale sloughing was observed and was the reason for NPT such as landing, overpull and reaming tight. However, these shale-dominated intervals are not thick; therefore shale sloughing did not grow into the upper and lower intervals from the sloughing interval. The caliper data in Figure 2.4 confirms that wellbore failure in the shale intervals was not severe. Overall, the Klinsovsko-Mosolovski section needs to be checked for clay mineralogy. There is a high possibility that the clay in this horizon is less reactive or potassium/uranium enriched, which can be a reason for the absence of wellbore-stability issues at the drilling stage. Also, the shale in this horizon might be hydrocarbon source.
Table 2.6   Key Operational Parameters Used for Drilling the Klinsovsko-Mosolovski Horizon in the 6 inch Section, Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>4983 / 5123</td>
<td>4939 / 5030</td>
<td>ARL 5-20% and LST / DLT 80-95%</td>
<td>36 / 68</td>
<td>289 / 291</td>
<td>1.18 / 1.19 (9.85 / 9.93)</td>
<td>1.24 / 1.28 (10.35 / 10.68)</td>
<td>NaCl Polymer</td>
<td>Minor WBI in some intervals</td>
</tr>
</tbody>
</table>

Figure 2.4   The Klinsovsko-Mosolovski horizon in the 6 inch section, Well G.

2.2.2.2 Biyski horizon

After the Klinsovsko-Mosolovski horizon, the Biyski horizon was drilled. No significant wellbore-stability problems were encountered during drilling through this horizon. The key operational parameters used for drilling this horizon are shown in Table 2.7.

As in the previous Klinsovsko-Mosolovski horizon, the lithology in the Biyski horizon for this well is mostly represented by limestone and dolomite. Only small inclusions of argillites (up to 5%) were observed along this interval, except MD 5844-5847 m (TVD 5129 m), where the lithology was 100% argillite (Figure 2.5). However, since the shale thickness at this depth was only 1 m, there were no significant wellbore-stability problems except some landings.
Table 2.7  Key Operational Parameters Used for Drilling the Biyski Horizon in the 6 inch Section, Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>13</td>
<td>5123 / 5920</td>
<td>5030 / 5139</td>
<td>ARL 3-5% and LST / DLT 95-97%</td>
<td>68 / 82</td>
<td>291 / 294</td>
<td>1.19 (9.93)</td>
<td>1.27 / 1.29 (10.6 / 10.76)</td>
<td>NaCl Poly-mer</td>
<td>No WBS problems, except some shaly intervals</td>
</tr>
</tbody>
</table>

As in the previous Klinovsko-Mosolovski horizon, the lithology in the Biyski horizon for this well is mostly represented by limestone and dolomite. Only small inclusions of argillites (up to 5%) were observed along this interval, except MD 5844-5847 m (TVD 5129 m), where the lithology was 100% argillite (Figure 2.5). However, since the shale thickness at this depth was only 1 m, there were no significant wellbore-stability problems except some landings and overpulls. Besides the lithology effect, the wellbore inclination in this section could result in a positive impact on wellbore stability of this section. Again, as in the Klinovsko-Mosolovski section, the used mud weight was relatively low.

![Bit size and caliper](image1.png)

![Lithology: 100% Argillite](image2.png)

Figure 2.5  The Biyski horizon in the 6 inch section, Well G. At 5845 m, the lithology is 100% shale, but no washouts were observed.

2.2.2.3  Emsian stage

The last stage drilled in this well was the Emsian stage. Only 22 m (TVD 3 m) were drilled in this stage before the TMD was reached. The key operational parameters used for
drilling this short section are in Table 2.8 which is very similar to the parameters shown in Table 2.7. No significant drilling challenges and hole-stability issues occurred during entering the top of the Emsian stage. Since not enough data is available for this section, it was assumed that the shale behavior of the upper Emsian stage might be very similar to those described for the Biyski horizon.

Table 2.8  Key Operational Parameters Used for Drilling the Emsian Stage in the 6 inch Section, Well G

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Az. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>13</td>
<td>5920</td>
<td>5139</td>
<td>ARL 30% and LST 70%</td>
<td>82</td>
<td>292</td>
<td>1.19 (9.93)</td>
<td>1.28 (10.68)</td>
<td>NaCl Polymer</td>
<td>No WBS issues</td>
</tr>
</tbody>
</table>

2.3 Case Study for Well H

To diagnose the troubles encountered at Well H during directional drilling from MD 4680 m (KOP) to TMD 5629 m, a detailed analysis of conducted operations and well-log results was performed. The collected key operational data for the analysis includes the number of days spent on drilling this horizon, MD, TVD, MW, ECD, borehole inclination as well as azimuth, lithology and operation comments. The purpose of this diagnosis is to identify the formation and lithology that complicate drilling operations and to estimate the NPT due to the wellbore-stability issues if any exist. Also, the MW, ECD, wellbore inclination and azimuth will be evaluated to find the influence of these parameters on wellbore-stability troubles during directional drilling of this well. Problem diagnosis was started from the KOP.

2.3.1 Eight and half inch Section

Well H was vertically drilled to KOP at 4680 m (TVD 4680 m) with the open hole size of 8 ½ inches. Then, the 8 ½ inch section was drilled to MD 5048m with the inclination of 58 degrees and azimuth 191 degrees. PCL was not performed up to the planned depth due to landings at MD 4952 m. While running, the 7 inch casing got stuck at MD 5016 m. It was
cemented with 4 m³/hr mud losses. Excessive surge pressure while running the 7 inch casing was a cause of mud loss.

The 8 ½ inch section of Well H was drilled through the Upper Devonian period (Famennian stage, D3fm) and partially the Middle Devonian period. The Middle Devonian was represented by the Givetian (Mullinski, Ardatovski and Vorobevski horizons) and Eifelian stages (Chernoyarovski horizon).

2.3.1.1 Famennian stage

The Famennian stage was directionally drilled without any significant drilling issues from 4680 m to 4840 m (4680–4833 m TVD) with the maximum inclination of 28.5 degrees and 186 degrees azimuth at MD 4840 m. To analyze the reasons for the absence of wellbore-stability issues in the Famennian stage, the key operational data was collected. This data is shown in Table 2.9.

Table 2.9 Key Operational Parameters Used for Drilling the Famennian Stage in the 8 ½ inch Section, Well H

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>4680</td>
<td>4814</td>
<td>LST 73% and DLT 7%</td>
<td>2 / 23</td>
<td>230 / 184</td>
<td>1.19 (9.93)</td>
<td>1.21 / 1.24 (10.1 / 10.35)</td>
<td>Per-flex Polymer</td>
<td>No WBS</td>
</tr>
</tbody>
</table>

From Table 2.9, we assume that the reasons for the absence of wellbore-stability issues while drilling this section are lithology and low inclination. However, in evaluating the caliper log in the Famennian stage (Figure 2.6), we can observe washouts up to 12 inches while the nominal bit size was 8 ½ inches. From this information we can derive that even in carbonates the time-dependent formation weakening occurred in the interval 4640-4680 m. The reasons for the formation weakening can be filtrate invasion, which changes rock properties and alters stresses due to the bottom hole temperature change during circulation and tripping operations. Porosity and permeability of the washed interval need to be compared with the same parameters of the ingauge intervals in order to verify the correlation between filtrate invasion and washouts. Since
the inclusion of shale in this interval is negligible, the shale-filtrate interaction is not considered in this case. Impacts of the azimuth and mud weights are also not considered due to the low inclination angle in this interval. Even though no problems were encountered at this interval while drilling, washouts shown in Figure 2.6 suggest that this formation could contribute to the hole-cleaning issues occurred during drilling the Givetian stage.

The next stratigraphic stages drilled in the 8 ½ inch section, after the Famennian stage, were the Givetian (the Mullinski, Ardatovski and Vorobevski horizons) and Eifelian stages (the Chernoyarovski horizon). Severe wellbore-stability issues, such as landings, overpulls, incomplete PCL, casing stuck and LIH BHA, were experienced while drilling and tripping through these two stratigraphic stages. To determine intervals influenced by the wellbore-stability troubles, a detailed analysis of available well logs and drilling data was conducted. Again, the key operational data was collected in Tables 2.10, 2.11, 2.12, 2.13 and 2.14.

![Diagram showing bit size, hole size, and lithology](image_url)

**Figure 2.6** The Famennian stage in the 8 ½ inch section, Well H. Washouts are in limestone and dolomite intervals.

### 2.3.1.2 Mullinski horizon

While drilling the Mullinski horizon, no significant wellbore-stability issues were encountered. The key operational parameters used for drilling this section are shown in Table 2.10.
Table 2.10  Key Operational Parameters Used for Drilling the Mullinski Horizon in the 8 ½ inch Section, Well H

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4814 / 4840</td>
<td>4810 / 4837</td>
<td>LST 0-73%, DLT 20-60%, ARL 10-40%</td>
<td>23 / 30</td>
<td>186</td>
<td>1.19 (9.93)</td>
<td>1.21 / 1.24 (10.1 / 10.35)</td>
<td>Per-flex Polymer</td>
<td>No WBS issues. Washouts</td>
</tr>
</tbody>
</table>

However, as seen in Figure 2.7, there are obvious washouts at MD 4815 m (washout diameter – 12 inches) and at 4842 m (washout diameter – 17 ¾ inches). The last depth corresponds to the transition from the Mullinski horizon to the Ardatovski horizon. Because no indications of wellbore-stability and hole-cleaning issues were observed, such as SPP increase, torque fluctuation and cavings, we can assume that the main reason for the wellbore failure at this horizon was the time effect. Time effect implies formation weakens due to the filtrate invasion after some period of the formation-mud contact. The presence of argillite at MD 4842 m could exacerbate and accelerate the formation-failure process due to chemical interactions.

![Figure 2.7 The Mullinski horizon, 8 ½ inch section. Washouts at the MD 4815 m and 4842 m.](image)
2.3.1.3 Ardatovski horizon

Drilling the upper part of the Ardatovski horizon was smooth without wellbore-stability or hole-cleaning problems. The key operational parameters used for drilling this interval are shown in Table 2.11, and the log plot is illustrated in Figure 2.8.

Table 2.11 Key Operational Parameters Used for Drilling the Upper Part of the Ardatovski Horizon the 8 ½ inch Section, Well H. The Interval is without Significant Washouts

<table>
<thead>
<tr>
<th>#of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azimuth deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>4840 / 4896</td>
<td>4837 / 4880</td>
<td>LST 20%, DLT 20-40%, ARL 10-60%, SS 40-75%</td>
<td>30 / 40</td>
<td>187 / 189</td>
<td>1.19 / 1.19 (9.93)</td>
<td>1.21 / 1.24 (10.1-10.35)</td>
<td>Per-flex Polymer</td>
<td>No WBS issues</td>
</tr>
</tbody>
</table>

Figure 2.8 The Ardatovski horizon, 8 ½ inch section. No washouts are in the interval 4860-4910 m.

The information from Table 2.11 and Figure 2.7 was integrated and analyzed to understand the reasons for successful drilling at the interval 4840-4896 m. Two main parameters were derived that could contribute to the close-to-in-gauge drilling results. One of these parameters is the lithology. As shown in Figure 2.7, the dominant lithology in the interval of interest is sandstone. Rock properties of the sandstone in this interval need to be evaluated. Another parameter that could have a high impact on wellbore stability is the hole inclination.
which was less than 40 degrees in this interval. However, severe washouts were observed in upper intervals, such as the Famennian and Mullinski, where the inclination was lower than 30 degrees. Evaluation of drilling operations and well logs at the same horizons while drilling the 6 inch section in this well can facilitate the determination of the key wellbore-stability parameters.

The first indications of wellbore-stability related problems started at MD 4896 m (TVD 4880 m). At this depth overpulls up to 15 tons were observed. From MD 4896m (Figure 2.8) the lithology changes from predominantly sandstone to siltstone. It is also the depth with severe washouts. Even though significant washouts in the Ardatovski horizon were presented, as at the depth 4935 m (Figure 2.9), the hole cleaning performance was sufficient to avoid pack-off issues. Analysis of the short-trip and round-trip results when no overpulls or landing were observed confirms the acceptance of the key hole cleaning parameters at the Ardatovski horizon as shown in Table 2.12.

Table 2.12  Key Operational Parameters Used for Drilling the Lower Part of the Ardatovski Horizon in the 8 ½ inch Section, Well H. The Interval Has Significant Washouts

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>4896 / 4940</td>
<td>4880 / 4913</td>
<td>LST 35-60%, SS 40-65%</td>
<td>40 / 42</td>
<td>189 / 192</td>
<td>1.19 (9.93)</td>
<td>1.21 / 1.24 (10.1 / 10.3)</td>
<td>Per-flex Polymer</td>
<td>Overpulls up to 15 tons. No hole cleaning issues</td>
</tr>
</tbody>
</table>

Figure 2.9  The Ardatovski horizon (lower part), 8 ½ inch section. Washouts are in the interval 4920-4940 m.
2.3.1.4 Vorobevski horizon

The next horizon drilled after the Ardatovski horizon in the 8 ½ inch section was the Vorobevski horizon. The drilling performance analysis showed no significant wellbore-stability issues with drilling this horizon. No 8 ½ inch open-hole-logging data is available for this interval to correlate the acceptable drilling performance in this horizon with the caliper data. However, the 6 inch open-hole-logging data for the Vorobevski horizon can be used to obtain a correlation between the drilling performance and key operational parameters. The key parameters used for drilling the Vorobevski horizon in the 8 ½ inch section are shown in Table 2.13. Since the 8 ½ inch logging data was not available for this interval, mud logging reports were used to obtain the lithology for the Vorobevski horizon. The domination of limestone in this horizon could be a reason for avoiding borehole-stability problems.

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>4940 - 4980</td>
<td>4913 - 4939</td>
<td>LST 30-90%, ARL 10-55%</td>
<td>43 / 47</td>
<td>194</td>
<td>1.19 (9.93)</td>
<td>1.24 (10.35)</td>
<td>Perflex Polymer</td>
<td>No overpulls and landings during short/round trips</td>
</tr>
</tbody>
</table>

2.3.1.5 Chernoyarovski horizon

The Chernoyarovski horizon, drilled after the Vorobevski horizon, was a source of wellbore-stability challenges during drilling the 8 ½ inch section of Well H. Chipped-size-caving sloughing, observed from MD 4982 m, was one of the reasons for the stuck pipe, incomplete open-hole logging, stuck casing and time-consuming reaming. Since gas shows up to 35% were indicated during prolific chipped-sized-caving sloughing, we can extrapolate that an abnormally pressured shale interval was a primary reason for the shale-caving sloughing. Even though mud weight was gradually increased from 1.19 g/cc to 1.27 g/cc (9.9 to 10.6 ppg), as a response to the sloughing problems, it did not stop caving sloughing. Also, hole cleaning might be inadequate compared to a significant sloughing rate. As a result of the sloughing and lack of hole cleaning,
PCL tools could not reach the Chernoyarovski horizon, and the 7 inch casing got stuck at MD 5016 m. The key operational parameters used to drill this horizon (Table 2.14) need to be evaluated to obtain critical reasons for the wellbore-stability issues in this section.

Besides the lithology, dominated by siltstone in this horizon, the well inclination ranged between 47 and 58 degrees. These two parameters (from the 8 ½ inch hole section) were analyzed and compared to the key operational parameters used to drill the 6 inch hole at the same horizon in this well. The other important information we can extract from Table 2.14 is the number of drilling days versus total days spent for this horizon. Drilling the Chernoyarovski interval in this well took 4 days with chipped-size-caving sloughing and significant gas-show handling. A wiper trip performed immediately after reaching MD 5048 m did not show any hole-cleaning or tight-hole issues. That was a reason for keeping the mud weight range between 1.21-1.22 g/cc (10.1-10.2 ppg). This mud weight was not enough to keep the hole from sloughing, or additional sloughing was created due to excessive swab and surge pressures while tripping. Therefore, significant time was spent for PCL and reaming until finally the mud weight was raised to 1.27 g/cc (10.6 ppg). However, the hole was still sloughing even with this mud weight. Unfortunately, no caliper data is available for this horizon in the 8 ½ inch section to determine an exact sloughing interval. Another factor that could impact the siltstone sloughing could be the time effect. Since the Chernoyarovski interval was exposed to the mud about 17 days, there might have been enough mud-clay contact time to weaken shale intervals and facilitate the sloughing rate and volume. It is critical to drill and complete mud sensitive shale intervals as fast as possible unless a mud system is compatible with the clay minerals present in the formation.

Table 2.14  Key Operational Parameters Used for Drilling the Chernoyarovski Horizon in the 8 ½ inch Section, Well H. Severe Wellbore-Stability Issues Were Encountered

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/17</td>
<td>4980 / 5048</td>
<td>4939 / 4982</td>
<td>LST 0-25%, SLT 75-100%</td>
<td>47 / 58</td>
<td>191</td>
<td>1.19 / 1.27 (9.93 / 10.6)</td>
<td>1.24 / 1.29 (10.35 / 10.76)</td>
<td>Perflex Polymer</td>
<td>Severe sloughing, gas shows, hole cleaning issues, pipe and casing sticking, PCL run issues</td>
</tr>
</tbody>
</table>
2.3.1.6 Seven inch Casing Stuck and Collapse

While RIH, the 7 inch casing stuck and collapse occurred in this well. There are at least two factors that contributed to these problems. First, the mud weight during RIH the 7 inch casing was 1.27 g/cc (10.6 ppg), which is relatively higher than the mud weight used for drilling the upper part of this section. This mud weight, in combination with the surge pressures and poor hole cleaning, was the reason for mud losses (4-5 m³/hr) during RIH the 7 inch casing. Usually, a mud weight used for RIH a 7 inch casing in vertical wells in this field is in a range of 1.17-1.19 g/cc (9.7 - 9.9 ppg). The reason for increasing the mud weight to 1.27 g/cc (10 ppg) was an attempt to stop the shale sloughing. The second factor was the decision to pump lost circulation materials (LCM) when the casing had not yet reached the planned shoe depth. Pumped LCM, together with mud solids, created a bridge around the 7 inch casing and packed it off. This second factor might be considered as a human error in that situation. Except obvious recommendations to mitigate wellbore-stability problems and to improve a hole-cleaning program, two follow up recommendations exist. First of all, it is highly recommended to run an auto-fill type shoe track in order to reduce a surge pressure while RIH casing strings. Moreover, control of a pipe velocity is also a critical factor in reducing surge pressure values. Acceptance of the second recommendation depends on the severity of mud losses during RIH casing strings. If a mud loss rate is relatively moderate as it was in this case, it is critical, first, to reach a planned casing set depth. Only after that, start working on reducing mud losses before cementing operations. In case a depth for the mud loss is determined by running a temperature gauge on a wireline, it would be possible to derive an estimated surge pressure for a mud loss depth and to correlate that value to the calculated minimum horizontal stress magnitudes.

2.3.2 Six inch Section

After determining the 7 inch casing collapse depth, a whipstock system was set MD 4962 m, which corresponds to the Vorobevski horizon. While drilling, MD 4978 m, which is the top of the Chernoyarovski horizon, string pack-off took place. After jarring, the string got free, and circulation was re-established. Bottoms-up cuttings were 10% limestone and 90% siltstone. Then, at MD 5004 m (TVD 4960 m) the string got packed-off again. It is the same problematic TVD encountered during drilling the 8 ½ inch section in the Chernoyarovski horizon. Jarring did not bring any positive results, so the BHA was LIH. Before the string pack-off was observed, a
fluctuation of the SPP and TQ occurred, which is considered to be a sign of a string-packing tendency. The key parameters used to drill this part of the 6 inch section in Well H are shown in Table 2.15.

Based on the parameters in Table 2.15, there are a few potential reasons for the wellbore failure and LIH. First of all, setting the whipstock at the Chernoyarovski horizon with the shale-dominated lithology could be the cause of the immediate formation sloughing observed during drilling at the casing exit. Also, the attempt to drill this section with the reduced mud weight (1.18 g/cc, 9.8 ppg) could accelerate the wellbore failure. Moreover, the wellbore vicinity at the whipstock depth could be affected by a stress alteration caused by drilling the 8 ½ inch section. The possible causes for the severe wellbore-stability issues during drilling this short 6 inch section can be narrowed down by analyzing the 6 inch sidetrack section drilled in this well.

Table 2.15  Key Operational Parameters Used for Drilling the Chernoyarovski Horizon in the 6 inch Section, Well H. Severe Wellbore-Stability Issues Were Encountered

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>4980</td>
<td>4939</td>
<td>LST 0-10%, SLT 90-100%</td>
<td>47</td>
<td>185</td>
<td>1.18 (9.85)</td>
<td>1.24 (10.35)</td>
<td>KCL / Polymer</td>
<td>Severe sloughing, hole cleaning issues, pipe sticking, LIH BHA</td>
</tr>
</tbody>
</table>

2.3.3 Six inch Section (Sidetrack)

After failing to drill the 6 inch section from the Chernoyarovski horizon, a kick-off plug was set on the top of the LIH BHA. Then, a whipstock system was set at MD 4772.7 m which corresponds to the Famennian stage. This 6 inch section was drilled with a relatively good performance and without severe wellbore-stability issues. Using the same diagnostic model, key operational parameters used to drill each encountered horizon were evaluated to explain the reasons for the successful and/or problematic drilling performance.
2.3.3.1 Famennian stage

Drilling of the 6 inch section through the Famennian stage was smooth without any significant wellbore-stability issues. The key operational parameters used for drilling this part of the 6 inch section are shown in Table 2.16.

Table 2.16  Key Operational Parameters Used for Drilling the Famennian Stage in the Sidetracked 6 inch Section, Well H. No Wellbore-Stability Issues Were Encountered

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>4770/4814</td>
<td>4769/4811</td>
<td>DLT 98%, ARL 2%</td>
<td>14</td>
<td>186</td>
<td>1.18 / 1.22 (9.85 / 10.2)</td>
<td>1.27 (10.6)</td>
<td>KCL Poly</td>
<td>No WBI</td>
</tr>
</tbody>
</table>

The in-gauge hole illustrated in Figure 2.10 correlates with the good drilling performance observations. In order to identify the reasons for the absence of wellbore-stability issues in this interval, the key parameters in Table 2.16 were evaluated. The main reason for no wellbore-stability issues is considered to be the lithology which is dominated by limestone and dolomite in the Famennian stage. Even though the Famennian stage was exposed to the whole 6 inch section drilling time, the time effect was not an issue for this stage with the given parameters. Stress alterations at the Famennian stage were negligible in causing the rock to weaken over the designated time period. The low borehole inclination in this stage could also be the reason for this trouble-free performance. It is important to note that the mud system for the 6 inch section was changed from the PERFLEX to the KCl system. More information about the PERFLEX mud system can be found in Appendix A. To evaluate the difference in the performance between these two mud systems, the well logs for the 8 ½ inch and 6 inch sections of the Famennian stage were analyzed. The well-log plot of the 8 ½ inch section of the corresponding interval is illustrated in Figure 2.11.

It can be clearly seen from these two figures that the caliper log of the 6 inch section is close to in-gauge while the caliper log of the 8 ½ inch section shows some hole diameter increase at the same Famennian stage interval. The most probable reason for this difference can be the
better the better efficiency of the KCl system. The accuracy of this assumption needs to be checked by evaluating 8 ½ inch and 6 inch section logs at shale intervals.

Figure 2.10  The Famenian stage, sidetracked 6 inch section. No washouts in the log plot correlate with the successful drilling performance in the interval 4770-4814 m.

Figure 2.11  The Famennian stage, 8 ½ inch section. The deviation in the caliper log in the interval 4780-4814 m could be due to the time effect and chosen mud type.

2.3.3.2 Mullinski horizon

Similar to the Famennian stage, the Mullinski horizon was drilled without any wellbore-stability problems. The key operational parameters used for drilling this horizon are shown in
Table 2.17. From Figure 2.12, a close-to-in-gauge hole in the 6 inch section of the Mullinski interval is in good agreement with the stable performance observed during the drilling. The comparison between the key parameters used for drilling this interval (Table 2.17) with the same interval in the 8 ½ inch section, shown in Table 2.16, gives insight into the reasons for the two different behaviors. The following parameters have been analyzed to explain this performance difference:

- wellbore inclination
- mud weight
- mud system

These three parameters are different in the two key parameter datasets considered and could be the reasons for the different wellbore-stability behavior.

The first parameter is the wellbore inclination. The inclination of the 8 ½ inch section at the Mullinski horizon was in the range of 23-30 degrees. This is not considered to be a critical factor for the hole cleaning, yet, it is higher than the inclination in the 6 inch section at the Mullinski horizon. Another parameter is the mud weight. The mud weight used for drilling the 8 ½ inch section in the Mullinski horizon was 1.19 g/cc (9.9 ppg), which is less than the mud weight used to drill the same horizon in the 6 inch section.

Finally, different mud systems used in the 8 ½ inch and 6 inch sections could also be the reason for the time affected wellbore-stability behavior. Possibly, the KCl system had more formation compatibility than the PREFLEX system used in the 8 ½ inch section.
Figure 2.12 The Mullinski stage, sidetracked 6 inch section. No washouts in the log plot correlate the successful drilling performance in the interval 4814-4840 m.

Figure 2.13 The Mullinski horizon, 8 ½ inch section. The deviation of the caliper log in the interval 4814-4840 m could be due to the time effect, well inclination and chosen mud system

2.3.3.3 Ardatovski horizon

No wellbore-stability problems were encountered during drilling the 6 inch section through the Ardatovski horizon. The key operational parameters used for drilling this part of the 6 inch section are shown in Table 2.18. The caliper log in Figure 2.14 shows the in-gauge hole throughout the whole Ardatovski horizon in the 6 inch section even though this horizon was dominated mostly by siltstone. This figure helped in understanding that time effect was not an issue for this horizon with the given key operational parameters. On the other hand, a totally different situation was observed during drilling the same horizon in the 8 ½ inch section. The log plot for the Ardatovski horizon in the 8 ½ inch section is illustrated in Figure 2.15.
Table 2.18  Key Operational Parameters Used for Drilling the Ardatovski Horizon in the Sidetracked 6 inch Section, Well H. No Wellbore-Stability Issues Were Observed

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>4840 / 4922</td>
<td>4836 / 4915</td>
<td>DLT 10-65%, LST 35-65%, SLT 30-65%, SS 0-60%</td>
<td>17</td>
<td>180</td>
<td>1.22 (10.18)</td>
<td>1.28 / 1.31 (10.68 / 10.9)</td>
<td>KCL / Polymer</td>
<td>No WBI</td>
</tr>
</tbody>
</table>

Figure 2.14  The Ardatovski horizon, 6 inch section. No washouts in the log plot correlate the successful drilling performance in the interval 4840-4922 m.

Figure 2.15  The Ardatovski horizon, 8 ½ inch section. The deviation in the caliper log in the interval 4840-4922 m could be due to the time effect and wellbore inclination.
During drilling the 8 ½ inch section through the Ardatovski horizon, a number of washouts were observed in this interval, correlating the encountered landings and overpulls. To analyze this difference, the key operational parameters used to drill the Ardatovski horizon in the 8 ½ and 6 inch sections were evaluated (Tables 2.12 and 2.18). Again, there are three parameters which are different in these two cases: the wellbore inclination, mud weight, and mud system. As can be seen from Tables 2.12 and 2.18, a higher mud weight was used in the 6 inch section, while the inclination in this section was less than in the 8 ½ inch section. Also, a KCl mud system was used for drilling the 6 inch section while utilizing the PERFLEX system for the 8 ½ inch section.

To narrow down the range of causes for the different formation behavior in these two sections, a comparison of rock properties for the 6 inch and 8 ½ inch cases was conducted. This comparison will help to evaluate the impact of the mud type on this difference. The impact of the mud weight and inclination has been derived from a numerical wellbore-stability model that will be discussed in a subsequent section.

### Vorobevski horizon

The Vorobevski horizon was also drilled without any wellbore-stability issues in the 6 inch section. The key operational parameters used to drill this horizon are shown in Table 2.19.

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Az. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>4922 / 4948</td>
<td>4915 / 4939</td>
<td>DLT 23%, LST 60%, SLT 15%, SS 2%</td>
<td>16</td>
<td>181</td>
<td>1.22 (10.18)</td>
<td>1.28 (10.68)</td>
<td>KCl Polymer</td>
<td>No WBS issues</td>
</tr>
</tbody>
</table>

Based on drilling reports, there were no significant wellbore-stability problems encountered during drilling this horizon in the 8 ½ inch section. Unfortunately, PCL did not cover this lithology in the 8 ½ inch hole. However, by integrating the key operational parameters
from Tables 2.13 and 2.19 with the Vorobeyski horizon log plot for the 6 inch section (Figure 2.16), it was possible to extrapolate the data to determine the reasons for well stability in this horizon. The relevant parameters are the well inclination, mud weight, mud type and lithology, which is dominated by limestone. As can be observed in Figure 2.16, there are no washouts even at the intervals which are dominated by siltstone (MD 4950 m).

2.3.3.5 Chernoyarovski horizon

Another horizon drilled without wellbore-stability problems in the 6 inch sidetracked section is the Chernoyarovski horizon. The key operational parameters used to drill this horizon are shown in Table 2.20. Even though the logging data from the 8 ½ inch section is not available for this horizon, according to daily drilling data, this horizon was the main source of the severe wellbore-stability issues in the 8 ½ inch section. The available caliper log data from the 6 inch borehole, plotted in Figure 2.17, shows no serious washouts in this horizon even at the highly shaly intervals.

Analyzing data from Tables 2.20 and 2.21, in combination with the caliper and lithology data illustrated in Figure 2.17, it can be extrapolated that the main reason for the absence of wellbore-stability issues in the 6 inch Chernoyarovski sidetracked section is the wellbore inclination. This 6 inch section was intentionally drilled with a low well inclination. Obviously, that decision brought positive results in terms of keeping the wellbore stable. The mud weight
Table 2.20  Key Operational Parameters Used for Drilling the Chernoyarovski Horizon in the 6 inch Sidetracked Section, Well H. No Wellbore-Stability Issues Were Observed

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>4948 /5011</td>
<td>4939 /5000</td>
<td>LST 0-40%, SLT 40-100%, SS 0-60%</td>
<td>14</td>
<td>181</td>
<td>1.23 / 1.25 (10.26 / 10.43)</td>
<td>1.31 (10.93)</td>
<td>KCl Polymer</td>
<td>No WBS issues</td>
</tr>
</tbody>
</table>

evaluation in the Chernoyarovski horizon for both the 6 inch and 8 ½ inch sections gave interesting results. First, in the 8 ½ inch section, the mud weight was increased up to 1.27 g/cc (10.6 ppg) at the Chernoyarovski interval due to sloughing of chipped-size-siltstone cavings. Gas shows during drilling this interval indicated an over-pressured shaly zone. Second, the mud weight in the 6 inch section was increased up to 1.25 g/cc (10.4 ppg) due to high gas shows, but not because of siltstone sloughing. Another reason for the drilling performance discrepancy in these two sections could be the two different drilling mud type systems. Based on the analysis of this horizon, wellbore inclination is a major factor for the wellbore-stability control during drilling the sidetracked 6 inch borehole through the Chernoyarovski horizon.

Figure 2.17  The Chernoyarovski horizon, 6 inch sidetracked section. No washouts in the log plot correlate the successful drilling performance in the interval 4948-5011 m.
2.3.3.6 Klinsovsko-Mosolovski horizon

After the Chernoyarovski horizon, the Klinsovsko-Mosolovski horizon was successfully drilled. Even though some shale sloughing was observed in the interval 5070-5081 m, this did not complicate the drilling process. The key operational parameters used to drill this horizon in the 6 inch section are shown in Table 2.21. The available logging data for this horizon is illustrated in Figure 2.18.

The integration of drilling reports with the log analysis helped to interpret the correlation between the absence of wellbore-stability issues during drilling and the enlargements shown on the log plot. The only borehole-stability issue indicated during drilling the Klinsovsko-Mosolovski horizon in the 6 inch sidetracked section was the chipped-sized-shale caving sloughing at the interval 5070-5081 m. However, that was not a long-term sloughing, and it did not create any drilling issues.

Table 2.21   Key Operational Parameters Used for Drilling the Klinsovsko-Mosolovski Horizon in the Sidetracked 6 inch Section, Well H. No Wellbore-Stability Issues Were Observed

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azl. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>5011 / 5150</td>
<td>5000 / 5106</td>
<td>LST 95%, ARL 3-100%, DLT 0-20%</td>
<td>15 / 63</td>
<td>181 / 190</td>
<td>1.23 / 1.24</td>
<td>1.31 (10.93)</td>
<td>KCl Polymer</td>
<td>No WBS issues, shale sloughing at 5070-5081m</td>
</tr>
</tbody>
</table>

There are, at least, four factors which explain why the sloughing was not prolonged: the lithology, wellbore inclination, mud weight and mud type. As can be seen from Figure 2.18, the lithology at the interval 5070-5081 m is dominated by limestone. Therefore, the sloughing interval is probably 5100-5115 m, where a higher shale factor in the lithology and bigger washouts exist. The shale intervals in the Klinsovsko-Mosolovski horizon are not massive, and as a result the washouts were not propagated to the upper and lower intervals. Another reason can be a relatively low value for the wellbore inclination. In this interval it was about 40 degrees, implying that hole cleaning was not an issue. The used mud weight could also be sufficient to
stop the sloughing propagation. Finally, KCl mud was able to inhibit a small fraction of shale in this interval.

On the other hand, the caliper log data in Figure 2.18 shows significant washouts all along the Klinsovsko-Mosolovski interval. The absence of wellbore-stability problems during drilling this section allowed it to be inferred that this washouts occurred in a continuous manner. Also, the hole cleaning was sufficient to clean a borehole experiencing slow-speed sloughing. It can be reasonably assumed that the “time effect” was a primary sloughing mechanism. In order to estimate an approximate time required to weaken a formation in the Klinsovsko-Mosolovski horizon, drilling and tripping reports were analyzed. According to those reports, the first indication of the washout existence, such as overpulls and landings, occurred 16 days after starting to drill the Klinsovsko-Mosolovski horizon. At that time Well H reached the TMD.
Estimating the time effect for different formations helps predict the safe drilling time after which a risk of rock weakening and sloughing increases.

Based on the data in Table 2.21 and the wellbore-stability behavior of Well H in the Klinovsko-Mosolovski section, it is reasonable to assume that it is feasible to drill this horizon even with the moderate well inclination and relatively low mud weight. However, the preferable azimuth selection, lithology comparison, and sufficient hole cleaning program were analyzed in detail before accepting this assumption.

2.3.3.7 Biyski horizon

Similar to the case of drilling Well G, no wellbore-stability problems occurred during drilling the Biyski horizon in the 6 inch sidetracked section of Well H. The key operational parameters used for drilling the 6 inch hole through the Biyski horizon are shown in Table 2.22.

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>5150 / 5560</td>
<td>5106 / 5148</td>
<td>LST 40%, DLT 60%</td>
<td>63 / 85</td>
<td>188 / 190</td>
<td>1.23 (10.26)</td>
<td>1.31 (10.93)</td>
<td>KCl Polymer</td>
<td>No WBS issues</td>
</tr>
</tbody>
</table>

The main reasons for the successful drilling performance in this horizon are the lithology and wellbore inclination that is greater than 65 degrees in this part of the 6 inch section. The lithology is represented by dolomite and limestone. According to drilling reports, there are few cases when landing and pipe stuck occurred at the interval 5200-5240 m. All those cases occurred during running or pulling out a stiff BHA. By integrating the caliper and well survey data, it is possible to find causes of those incidents. The interval 5200-5240 m, shown in Figure 2.19, is a transition zone from the build-up to the tangent sections; therefore, due to the well geometry and BHA stiffness, additional reaming occurred at this interval, explaining the ledges observed at the depth of 5232 m. Assuming that this is a correct explanation for the pipe sticking
and landing, it can be considered that the hole cleaning program in this section was sufficient to remove all cuttings to the surface.

Figure 2.19 The Biyski horizon, 6 inch sidetracked section. The indicated borehole enlargements resulted from the over-reaming due to BHA stiffness.

2.3.3.8 Emsian stage

After the Biyski horizon, 70 m of the Emsian stage was drilled with significant wellbore-stability issues. Rapid SPP and TQ increase and excessive reaming due to frequent overpulls and landings were experienced during drilling this short interval. The key parameters used for drilling the Emsian interval are shown in Table 2.23.

Table 2.23 Key Operational Parameters Used for Drilling the Emsian Stage in the Sidetracked 6 inch Section, Well H. Significant Wellbore-Stability Issues Were Observed

<table>
<thead>
<tr>
<th># of spent days</th>
<th>MD m</th>
<th>TVD m</th>
<th>Lithology</th>
<th>Incl. deg</th>
<th>Azi. deg</th>
<th>MW g/cc (ppg)</th>
<th>ECD g/cc (ppg)</th>
<th>Mud type</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>5560 / 5629</td>
<td>5148 / 5148</td>
<td>ARL 70-100%, DLT 30%</td>
<td>85</td>
<td>185</td>
<td>1.23 (10.26)</td>
<td>1.33 (11.1)</td>
<td>KCl Polymer</td>
<td>SPP and TQ increase, bit plugging, reaming</td>
</tr>
</tbody>
</table>
The data in Table 2.23 and log data in Figure 2.20 were analyzed. It is obvious that the lithology, dominated by argillites, was the main reason for the unstable wellbore behavior. Even though PCL tools did not reach to the TMD, and most of the logging data is not available below MD 5580 m, it is possible to extrapolate that the gamma ray data and caliper log fingering will be continuing toward TMD 5629 m. Obviously, the used mud weight was not enough to counteract the clay sloughing tendency in this interval. Also, the KCl mud, used to drill this section, was not compatible with Emsian argillites. Since the Emsian stage is not a source rock, it is not recommended to drill through this stage. A gamma ray sensor in the LWD system can help to avoid entering into this stage during drilling horizontal wells in the Biyski horizon.

Figure 2.20  The Emsian stage, 6 inch sidetracked section. Severe wellbore-stability issues occurred during drilling the interval 5580-5629 m.

Because of the low inclination at the Vorobevski and Chernoyarovski horizons and utilization of KCl mud, the sidetracked 6 inch section of Well H was drilled without significant wellbore-stability problems. However, the 4 ½ inch stuck liner due to high dog-leg severities (DLS) at the Klinovsko-Mosolovski horizon indicates that the short-radius trajectory creates completion issues. Therefore, it is necessary to conduct an integrated wellbore-stability analysis in order to determine a required safe mud weight to drill with a relatively low DLS. Also, severe wellbore-stability issues encountered during drilling the Emsian stage indicates that the Emsian stage should be a no-go layer.
2.4 3D Problem Visualization in Petrel

To better visualize the drilling performance in terms of wellbore stability, the same diagnostic coding discussed earlier was implemented. The code “0” represents the intervals where no wellbore-stability issues occurred. “1” shows the intervals with minor indirect wellbore-stability problems that were handled without pack-off and loss circulation incidents. Finally, the code “2” represents intervals where the severe wellbore-stability issues happened, such as the pipe stuck, loss circulation, PCL failure and sidetrack. Then, this coding system was utilized for Wells H and G and transferred to Petrel to determine if the wellbore-stability issues are associated with a particular horizon or not (Figures 2.21 and 2.22). The 3-D analysis of these figures shows that the Biyski and Klinsovsko-Mosolovski horizons are not problematic intervals in terms of wellbore stability. Moreover, the Vorobevski and Chernoyarovski horizons are represented with “2” and “1” codes for both wells. Therefore, these two horizons are considered to be the source of wellbore-stability issues. The minor fluctuation in coding for these two problematic horizons can be explained with the presence of the fault between the two wells (Figure 2.23).

![Cross sectional view of Well H with all horizons from the top of unconformity to the Emsian stage.](image-url)
Figure 2.22  Cross sectional view of Well G with all horizons from the top of unconformity to the Emsian stage.

Figure 2.23  Top view of Wells G and H with a fault between these two wells.
CHAPTER 3

GEOLOGICAL MODELING OF THE WEST KAZAKHSTAN FIELD AND
IN-SITU STRESS MAPPING FOR WELLBORE-STABILITY ANALYSIS

Considering the complex geology of the Pre-Caspian Basin and the West Kazakhstan Field, it is critical to integrate the geological model developed in our study into the wellbore-stability analysis. Even though the importance of this integration is well recognized (Tutuncu et al., 2006), geological data is typically not available for the service companies who provide analysis for the producing companies. An existing geological model from the West Kazakhstan Field was adapted as a basis for the geological modeling for this study. Note that, in the existing geological model for the West Kazakhstan Field, only productive net zones have been included in the geological model, while non-productive intervals were not considered. This modeling approach is acceptable from reservoir engineering and production optimization stand points. However, most wellbore-stability issues observed in this field of study corresponded to non-productive intervals, particularly to seal shales.

The primary goals of building this geological model are as follows:

- to incorporate the missing horizons in the geological model in the interval of interest (2700-5300 m),
- to analyze the wellbore-stability problems in 3D, and to better visualize problematic intervals in the model,
- to map the uniaxial compressive strength and in-situ principle stresses in each horizon for the entire field,
- to better understand the existing fault locations in the study field,
- to predict rock properties and stress distribution at a particular area based on available data from offset wells and presence of faults
3.1 Enhancement of the Existing Geological Model

The existing geological model consists of the Devonian fault map and three horizons. Those horizons are the top of the Fransian Unconformity, Klinsovsko-Mosolovski and Biyski layers. Since the intervals wellbore-stability problems experienced are above Klinsovsko-Mosolovski and Biyski horizons, the geological model was modified by adding new layers between the bottom of the Kungurian salt system (about 2700 m) and Emski horizon (at about 5300 m). This was a very important implementation since a few horizons are eroded in some parts of the West Kazakhstan Field due to the presence of the Fransian Unconformity (see Figure 3.1).

![Figure 3.1](image.png)

Figure 3.1  The surfaces of Vorobevski and Chernoyarovski horizons are eroded below the unconformity in the north-west and south-east parts of the field. These two horizons are considered to be a source for wellbore-stability issues. The bar scale is the depth (4740-4900 m) below the mean sea level.

The horizons above this unconformity are considered to be conformable. As mentioned in Chapter 1, the tilted block system exists below the Fransian Unconformity (see Figure 3.2).
Figure 3.2  A tilted block system below the Fransian Unconformity. The scale is depth (4740-4900 m) below the mean sea level.

Figure 3.3  The multilateral well (in red circle) was drilled without any wellbore-stability issues because the Vorobevski and Chernoyarovski horizons are eroded in this part of the West Kazakhstan field.
Therefore, in order to capture tilted block features in these zones, the existing key horizons were adapted as a basis for further modeling. These existing key horizons were modeled based on seismic data and represent an actual undulation of the horizons. It was found that the presence or absence of the Mullinski, Ardatovski, Vorobevski, and Chernoyarovski horizons in the stratigraphic column varies depending on the well location. Note that no wellbore-stability issues were experienced during drilling deviated wells in the area where the Mullinski, Ardatovski, Vorobevski, Chernoyarovski horizons are eroded. For instance, in Figure 3.3, the multilateral well is shown in the red circle. Since the shale-bearing Vorobevski and Chernoyarovski horizons are not presented in the stratigraphic column of this well, both laterals were drilled without any wellbore-stability issues. On the other hand, these horizons are present in the wells with wellbore–stability issues. It should be acknowledged that, besides the fact of presence of these horizons, the wellbore inclination and azimuth play a dominate role in wellbore-stability issues.

3.2 3D Petrophysical Model

The basic steps used to build the 3D petrophysical model in this study are as follows:

1. pick new well tops
2. create new surfaces
3. make simple grid
4. make layers
5. perform geometrical modeling
6. scale up well logs
7. perform data analysis
8. perform 3D petrophysical modeling.

A selection of well tops from the well logs is an important starting step in building up new horizons. Primarily, the gamma ray, clay volume, and dynamic Young’s modulus data has been used as a basis for the well top selection in the Petrel software package (Figure 3.4). In total, 20 well tops were picked from 2700 m to 5300 m. Then, using the selected well tops, 20 surfaces were created. Recommendations of Schlumberger geologists were taken into account while creating unconformable surfaces below the Fransian Unconformity. The simple grid size used was 250x250 m. The thickness of each layer was 5-6 m. After performing geometrical modeling, the well logs of the principle stresses and UCS were upscaled. While the overburden
stress was horizontally up-scaled, the horizontal stresses and UCS were up-scaled along layers. The anisotropy range in the petrophysical modeling step was set as 500x500 m in the x-y plane and 10 m in the vertical plane. While the moving average technique was utilized for the 3D petrophysical modeling of the overburden stress, the kriging method was used for the principle horizontal stresses and UCS.

The up-scaled overburden stress, minimum and maximum horizontal stresses, and UCS are illustrated in Figures 3.5-3.8.

Figure 3.4 Selection of well tops in the Devonian interval. Track 1 is measured depth in m; Track 2 is clay volume in fraction; Track 3 is gamma ray in gAPI; Track 4 is bulk density in g/cm³; Track 5 is dynamic Young’s modulus.
Figure 3.5   The upscaled overburden stress using the density logs from the wells in the area. The color bar range is 40-140 MPa.

Figure 3.6   The upscaled maximum horizontal stress using geological analysis, well log and other data obtained in the field. The color bar range is 40-130 MPa.
Figure 3.7  The upscaled minimum horizontal stress. The color bar range is 40-110 MPa.

Figure 3.8  The upscaled UCS. The color bar range is 30-150 MPa.
3.3 Fault Mapping and Implication to the Stress Regime

The inclinations and orientations of the faults can infer the tectonic history of the West Kazakhstan Field. The near-vertical Devonian faults are illustrated in Figure 3.9. The main orientation of most faults is east-west. Some faults are oriented to north-west south-east, which is, according to FMI interpretations, the current direction of the maximum horizontal stress. Similar faults are observed in the Carboniferous age intervals (Figure 3.10). According to Zoback (2010), the near-vertical faults imply the existence of the strike-slip stress regime when the faults were formed. The derived strike-slip stress regime in the West Kazakhstan Field is in agreement with observed fault interpretations.

Figure 3.9 The map of the near-vertical Devonian faults in the West Kazakhstan Field.
Figure 3.10  The map of the near-vertical Carboniferous faults in the West Kazakhstan Field.
CHAPTER 4

INPUT DATA ACQUISITION FOR WELLBORE-STABILITY ANALYSIS

Input data acquisition is an important part of wellbore-stability analysis. The required input data we used in this study are listed below.

- overburden stress
- pore pressure
- bottom hole pressure and equivalent circulation pressure
- Biot’s coefficient
- static Poisson’s ratio
- static Young’s modulus
- uniaxial compressive strength of the formation
- tensile strength of the formation
- friction angle or friction coefficient
- orientations of the principle horizontal stresses
- magnitudes of the principle in-situ stresses

Methodologies used to obtain the input data and results are described in the subsequent sections.

4.1 Overburden Stress

The overburden stress is a direct integration of the bulk density measured in the well of the interest area. Yet, it is essential to take into account that the bulk density value can be affected by near-wellbore washouts and water-shale adverse interactions that will result in measuring a lower than actual bulk density value (van Oort et al., 2001). The “stress arching” effect can cause the difference between the calculated overburden stress and the actual one. In this study, due to the small values of dip angles and the early stages of production with no depletion effect encountered yet, the “stress arching” effect does not a significant impact on the
overburden stress and has not been considered. The 3-D model of the overburden stress in the field of study is illustrated in the geological modeling part of the thesis in Chapter 3.

4.2 Pore Pressure Prediction

Understanding geological history of the field with distinguishing hydrocarbon trapping mechanisms at various intervals is critical in pore pressure prediction that we calculated in this study. The predicted pore pressure is one of the key parameters for constraining the in-situ stress state in the study field that is implemented in an integrated wellbore-stability model. Predicted pore pressure has facilitated solving wellbore-stability issues encountered during drilling vertical and horizontal wells in the West Kazakhstan Field. In a general case, pore pressure is a critical parameter for successful drilling operations, reservoir characterization, and production optimization. In the tight formations of our study, pore pressure prediction is a significantly challenging task. Therefore, most of the reliable pore pressure data in the West Kazakhstan Field is obtained in productive reservoir intervals from pore pressure measurements utilizing the wireline tools. Data from well testing analysis can also be an important source in pore pressure determination. However, in order to solve wellbore-stability problems encountered during drilling vertical and horizontal wells in the West Kazakhstan Field, it is critical first to determine pore pressure not only in the productive intervals, but also in the overburden intervals. With the geological complexities including unconformity and tilted fault systems in the area of interest, uniform pore pressure distribution throughout the field might create misleading predictions. One of the drilled wells in the central part of the field contained an abnormally high pressure zone just below the Frasnian Unconformity. The overpressure in this zone has been interpreted to be the result of compartmentalization in the faulted system that requires a specific determination of pore pressure in each inter-fault system.

The normal trend (Eaton) and explicit methods (Holbrook, Bower) are commonly used in the oil industry for pore pressure prediction. The critical parameters for the predictions in these methods have been determined using well and laboratory core data from the Gulf of Mexico, Gulf Coast, and North Sea fields. The methods of Holbrook, Bower and Eaton were used in this study for the West Kazakhstan Field with modifications, as it is an unconventional field with complex geology, geographically far from the area where the original databases for these methods were used.
4.2.1 Modified Eaton Method

It is essential to determine the normal pore pressure trend line, normal trend of compaction, and Eaton exponent (Eaton, 1975) to utilize the Eaton normal trend method for pore pressure prediction in the West Kazakhstan Field. The normal trend for pore pressure in the field of study is selected using a calcite/dolomite compaction line based on the available pore pressure measurement data. The normal trend for pore pressure is found to be 0.495 psi/ft. The normal sonic travel time is based on the calcite/dolomite compaction trend and shown in Figure 4.1.

![Figure 4.1](image-url)

Figure 4.1 The cross-plot of sonic travel time as a function of TVD, color-coded according to volume of shale in decimals. The red line shows the normal compaction trend that is selected based on a calcite/dolomite compaction line from available pore pressure measurement.

The sonic travel time in this figure is color coded according to the shale volume. This sonic travel time trend is used throughout the field. The original Eaton compaction coefficient used is 3 and requires significant modification to be implemented in tight unconventional reservoirs (Contreras et al., 2011). Different Eaton exponents were tried for calibrating the normal trend prediction. Eaton exponents in the range of 0.1 - 0.3 indicated better agreement between the predicted and measured pore pressure data. Note that the range of the Eaton exponents in 0.1 – 0.3 varies based on a well location in the inter-fault block system. The presence of faults in the
area impacts the local variations in pore pressure in different wells. The modified Eaton model was utilized in 17 wells in the field, 10 of which had in situ pore pressure measurement data. The comparison of the predicted pore pressure with real field measurements presented good agreement (Figure 4.2), except for the interval 4280-4400 m. This interval was considered to be a depleted compartment. The low pore pressure in this interval extends only in the east and central parts of the field, while in the rest of the field the predicted pore pressure in this interval is in close proximity to the actual measured pressures. It is critical to know the distribution of these abnormal low pressure zones in order to bypass possible mud losses during drilling activities. We modified our prediction in this interval by evaluating porosity data in the interval of interest and by setting different zones based on the porosity. Then, each assigned zone was tied to the MDT data. Note that low porosity intervals with high clay content did not have MDT measurements due to low permeability. Therefore, in these shaly/tight intervals, the Eaton method with 0.1-0.3 compaction coefficients was utilized. The agreement between the MDT data at different depths in the wells and the predicted pore pressure confirms that the Modified Eaton

![Figure 4.2](image-url) Pore pressure prediction using the Modified Eaton method shows good agreement to MDT data except in depleted interval.
Method, when adjusted for depleted intervals, is an acceptable methodology for pore pressure prediction in the West Kazakhstan Field.

4.2.2 Holbrook Method

One of the explicit pore pressure prediction methods implemented in this project is the Holbrook method. In this method, it is not required to set any normal trend lines due to the use of the relationship between the porosity, mineralogy, and effective stress in granular sedimentary rocks. The effective-stress law was used successfully in the North Sea to predict pore pressure in limestone, shaly limestone and sandstone intervals (Holbrook, 1999). Equation 4.1 is used to calculate the effective stress of the formation in the Holbrook method:

\[ \sigma_{eff} = \sigma_{max} \times (1 - \Phi)^{\beta} \quad \text{and} \]
\[ P_p = S_{ov} - \sigma_{eff}, \]

where \( \sigma_{max} \) is the effective stress required to reduce the mineral porosity to zero, \( \Phi \) is porosity from well logs, \( \beta \) is the compaction strain-hardening coefficient for the type of minerals, and \( S_{ov} \) is the overburden stress. The power-law-compaction coefficients for selected sediments are listed in Table 4.1.

It is important to note that the Holbrook method highly depends on the accuracy of the obtained porosity and lithology. The porosity and lithology identification data from Well A was used to calculate the effective stress for the entire interval of the study area using Equation 4.1. Limestone coefficients were utilized in the dolomite intervals. Then, the obtained effective stress was used in Equation 4.2 to calculate the pore pressure. The calculated pore pressure values were compared to the MDT in-situ test results for Well A. The difference in the calculated pore pressure versus the MDT pore pressure is +/- 0.01-0.03 g/cc (0.08-0.25 ppg) for clean limestone intervals. However, overall the pore pressure predicted using the Holbrook method has poor agreement to the MDT data as seen in Figure 4.3.

Core measurements with different facies are required to customize the power-law-compaction coefficients for tight formations in the West Kazakhstan Field and to improve the coefficient for more accurate pore prediction using the Holbrook pore pressure prediction.
Table 4.1  The Holbrook Coefficients Used to Predict Pore Pressure at Well A (Holbrook, 1999)

<table>
<thead>
<tr>
<th>Mineral (or Rock)</th>
<th>$\sigma_{max} \ psi$</th>
<th>$\beta$</th>
<th>Hardness (m ohs)</th>
<th>Solubility (ppm)</th>
<th>Grain density (g/cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz sand</td>
<td>130000</td>
<td>13.219</td>
<td>7</td>
<td>6</td>
<td>2.65</td>
</tr>
<tr>
<td>Average shale</td>
<td>18461</td>
<td>8.728</td>
<td>3</td>
<td>20</td>
<td>2.54-3.15</td>
</tr>
<tr>
<td>Calcite sand</td>
<td>12000</td>
<td>13</td>
<td>3</td>
<td>140</td>
<td>2.71</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>1585</td>
<td>20</td>
<td>2.5</td>
<td>3000</td>
<td>2.87</td>
</tr>
<tr>
<td>Halite sand</td>
<td>85</td>
<td>31.909</td>
<td>2</td>
<td>350000</td>
<td>2.16</td>
</tr>
</tbody>
</table>

Figure 4.3  Pore pressure prediction using the Holbrook method shows poor agreement to MDT data.

method. The coefficients listed in Table 4.1 and used in our prediction are for moderate porosity formations and require a better characterization of the compaction behavior for tight limestone, dolomite, sandstone and shale formations in the West Kazakhstan Field for higher accuracy in our study field.
4.2.3 Modified Bower Method

The modified Bower method was implemented as an alternative method in order to have a constraint in pore pressure using sonic logs. This method does not require establishing normal trend lines and is commonly used in predicting pore pressure when seismic data is present. The modification was made in establishing relationships between compressional and shear velocities and effective stress in the form of $V_p = a + b \times V_s + c \times \sigma_{eff}$. The coefficients a, b, and c were obtained using pore pressure MDT data from the wells and multi-linear regression analysis. The determination coefficients were greater than 0.90 in the Permian and Devonian intervals. Limited agreement was obtained between measured and predicted pore pressure using this relationship and the Modified Bower method. Therefore, the modified Bower method is not an optimal primary method for pore pressure prediction (Figure 4.4). Yet it can be used as a constraining limit for pore pressure determination.

Figure 4.4 Pore pressure prediction using the Bower method shows poor agreement to MDT data.

The pore pressure prediction in the West Kazakhstan field was obtained utilizing the Modified Eaton model with low (0.1 - 0.3) exponential coefficients. However, abnormal low
pressure zones in the depleted interval 4280-4400 m were not captured accurately by this model. Porosity and MDT data were coupled for different zonation for depletion adjustment in the depleted interval. Pore pressure distribution throughout the field shows that the complex geology of the West Kazakhstan Field has a great impact on pore pressure influencing the localized variations in pore pressure.

4.3 Bottom-Hole Pressure

Four bottom-hole-pressure scenarios have been considered in this section: hydrostatic bottom-hole pressure, surge pressure, swab pressure, and circulation pressure. Evaluating magnitudes of these pressure data provide us some constraint of the horizontal stress magnitudes utilizing wellbore breakouts and tensile failures.

4.3.1 Hydrostatic Bottom-Hole Pressure

Hydrostatic bottom-hole pressure was directly calculated by integrating the drilling fluid density. Besides considering the mud density variation due to hydrostatic pressure, it is important to compare the hydrostatic pressure calculated with the ECD and surge/swab pressures. Surge and swab pressures were calculated using the “steady-state” laminar flow and concentric wellbore assumptions for power-law fluids (Bourgoyne et al., 1986) and were compared to the hydrostatic and circulation pressures. The input data used and results are shown in Tables 4.2 and 4.3.

4.3.2 Equivalent Circulation Density (ECD)

Typically, circulating mud pressure is shown in terms of ECD. In this study ECD was obtained from daily mud reports. The mud service company uses Modified Power Law in their modeling of the mud pressure and ECD. The ECD calculated using this approach is shown in Table 4.3.

Since the highest ECD is expected to be during cementing operations, cementing ECD was also directly obtained from the end-of-cementing reports. The cement company used different rheological models in ECD calculations based on whether the fluid in the well was spacer, the drilling mud, or cement.
4.3.3 Surge and Swab Pressure

Typically, four different pipe-end conditions were considered in the commercial software package (Liu, 2011):

- open
- closed
- open with auto-fill or bit
- with flow diverter

In this study, only two of these pipe-end scenarios were appropriate: closed and open with bit. For surge pressure calculations, only a closed pipe condition has been considered due to the utilization of check or float valves in BHA and casing strings. An open with bit condition was used for swab pressure calculations with the assumption that a check (float) valve might start opening while tripping up. However, since a pipe velocity value in the field of study is moderate, the most reasonable scenario is a closed pipe end in both tripping up and down conditions. Therefore, even though it might be conservative, only closed-end pipe condition results are shown here.

A literature review was performed to analyze the existing methodologies in surge and swab pressure calculations. Burckhardt (1961) presented a simplified methodology to calculate the surge pressure assuming Bingham plastic fluids. An effective fluid velocity was used in this technique. A similar methodology for surge pressure calculations for power-law fluids was derived by Schuh (1964). Both models, representing “steady-flow” surge pressure models, were used to build a computer program to evaluate various parameters in surge and swab pressure calculations (Clark and Fontenot, 1974). Later, Wang and Chukwu (1996) captured drillstring acceleration effects in these calculations. Lubinski et al. (1977), Lal (1983), and Mitchell (1988) argued that “steady-state-flow” models comparatively over-predict the surge pressure when dynamic effects such as fluid inertia, fluid and wellbore compressibility and axial elasticity of a moving pipe are considered. Moreover, Hussain and Sharif (1997) and Srivastav et al. (2012) theoretically and experimentally showed the decrease of surge pressure with the wellbore eccentricity increase.
In this study, surge and swab calculations were performed using the “steady-state” laminar flow and concentric wellbore assumptions for power-law fluids (Bourgoyne et al., 1986). Input data for surge/swab pressure calculations are given in Table 4.2. The results of these calculations are presented in Table 4.3.

Table 4.2  Input Data For Surge/Swab Pressure Calculations

<table>
<thead>
<tr>
<th>Input data</th>
<th>Depth 4350 m</th>
<th>Depth 5030 m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud weight</td>
<td>1.17 g/cm³</td>
<td>1.17 g/cm³</td>
</tr>
<tr>
<td>θ₃₀₀</td>
<td>28</td>
<td>41</td>
</tr>
<tr>
<td>θ₆₀₀</td>
<td>42</td>
<td>60</td>
</tr>
<tr>
<td>Pipe velocity</td>
<td>1.25 ft/s</td>
<td>1.25 ft/s</td>
</tr>
<tr>
<td>DC length</td>
<td>100 m</td>
<td>100 m</td>
</tr>
<tr>
<td>DC OD</td>
<td>6.5 inches</td>
<td>6.5 inches</td>
</tr>
<tr>
<td>DP OD</td>
<td>5 inches</td>
<td>5 inches</td>
</tr>
<tr>
<td>OH size</td>
<td>8.5 inches</td>
<td>8.5 inches</td>
</tr>
<tr>
<td>9 5/8” casing set depth</td>
<td>2750 m</td>
<td>2750 m</td>
</tr>
<tr>
<td>9 5/8” casing ID</td>
<td>8.921 inches</td>
<td>8.921 inches</td>
</tr>
<tr>
<td>7” casing length</td>
<td>4350 m</td>
<td>5050 m</td>
</tr>
</tbody>
</table>

Table 4.3  Outputs from Surge/Swab Calculations

<table>
<thead>
<tr>
<th>Outputs</th>
<th>Depth 4350 m</th>
<th>Depth 5030 m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surge/Swab pressure</td>
<td>90 psi</td>
<td>166 psi</td>
</tr>
<tr>
<td>EMW of hydrostatic pressure</td>
<td>1.17 g/cm³</td>
<td>1.17 g/cm³</td>
</tr>
<tr>
<td>EMW of Surge pressure</td>
<td>1.1715 g/cm³</td>
<td>1.1898 g/cm³</td>
</tr>
<tr>
<td>EMW of Swab pressure</td>
<td>1.1685 g/cm³</td>
<td>1.1502 g/cm³</td>
</tr>
<tr>
<td>EMW of collapse pressure</td>
<td>1.25 g/cm³</td>
<td>1.6 g/cm³</td>
</tr>
<tr>
<td>ECD</td>
<td>1.23 g/cm³</td>
<td>1.24 g/cm³</td>
</tr>
</tbody>
</table>

As can be seen from the calculation results, surge and swab pressures in the West Kazakhstan Field are not significant. However, mud rheology and casing pipe velocity should be carefully controlled to avoid significant wellbore-pressure fluctuations while running casing strings.
4.4 Formation Properties

Acquisition of formation mechanical properties, such as Poisson’s ratio, Young’s modulus, tensile strength, uniaxial compressive strength (UCS), and friction angle, is of great importance in conducting wellbore-stability analysis. Formation properties are also important input parameters in identifying the local stress regime, key information in wellbore stability analysis. The chemical activity of drilling fluid and formation, together with the membrane efficiency, are also critical parameters to evaluate the pore pressure fluctuation due to formation-filtrate physico-chemical interactions. Typically, extensive laboratory experiments need to be conducted to acquire these formation properties. However, since no core was released for this study at the time of the completion of this study, all the parameters were obtained utilizing well-log data and appropriate empirical approaches. Methodologies and results of constraining the formation parameters discussed above are described in the subsequent sections.

4.4.1 Young’s Modulus and Poisson’s Ratio

Using the concept of elastic moduli equations described by Clark (1966), the dynamic compressive modulus \( M \), shear modulus \( G_s \), bulk modulus \( K \) along with the dynamic Young modulus \( E_d \) and Poisson’s ratio \( \theta \) have been calculated. The results of the calculations are shown in Figure 4.5. The elastic modulus equations used are shown in Equations 4.3 thru 4.7.

\[
\begin{align*}
\text{Dynamic Compressive Modulus (Pressure units)} & \quad M = \frac{\rho}{\Delta t_{co}}. \\
\text{Dynamic Shear Modulus (Pressure units)} & \quad G_s = \frac{\rho}{\Delta t_s}.
\end{align*}
\]

\[
\begin{align*}
\text{Dynamic Bulk Modulus (Pressure units)} & \quad K = M - \left(4 \times \frac{G_s}{3}\right) \\
\text{Dynamic Poisson’s Ratio} & \quad \theta = \frac{3K - 2G_s}{6K + 2G_s} \\
\text{Dynamic Young’s Modulus (Pressure units)} & \quad E = \frac{9G_sK}{G_s + 3K}
\end{align*}
\]

The compressional slowness \( \Delta t_{co} \) and shear slowness \( \Delta t_s \) used are in \( \mu\text{sec}/\text{ft} \). The bulk density \( \rho \) is in \( \text{g/cm}^3 \).
Figure 4.5  Calculated dynamic elastic moduli, Well A. Track 1 is a measured depth in m; Track 2 is Young’s modulus in GPa; Track 3 is compressional modulus in GPa; Track 4 is shear modulus in GPa; Track 5 is bulk modulus in GPa; Track 6 is Poisson’s ratio.

It is not very challenging to calculate the dynamic elastic moduli if bulk density and dipole sonic log (DSI) data are available and if the linear elastic rock assumption is used. In our study 8 out of 18 wells have DSI data in the intervals of interest. In 10 other wells shear slowness data were missing. However, compressional slowness data was recorded. Numerous researchers have studied estimations of shear velocity from clay volume, porosity, and other petrophysical
parameters using empirical correlations, and one should be cautious to directly utilize these equations. Han, Nur, and Morgan (1986) derived empirical equations to estimate the compressional and shear velocities in shaly sandstone with the known porosity and clay volume under a confining pressure of 40 MPa. Correlation of shaliness to $V_p/V_s$ ratio in shaly sandstone was also presented by Eastwood and Castagna (1983). Greenberg and Castagna (1992) developed an approach for estimating the shear velocities using empirical $V_p/V_s$ relationships and Gassmann’s fluid substitution equations. This method requires reliable data of compressional velocity, lithology, porosity, and water saturation of the formation of interest. Utilization of Gassmann’s equations in this methodology might be considered a significant simplification, since these equations are obtained for an isotropic homogenous rock unlike the tight formations that are typically highly anisotropic.

Later, Brie (2001) developed a model for estimating compressional and shear velocities in not only shaly sand, but for all sedimentary rocks including carbonates. Another methodology for obtaining a synthetic shear-wave velocity in carbonate formations was proposed by Kazatchenko et al. (2006). This methodology is based on the determination of matrix as well as secondary porosity values and secondary-pore shapes using compressional-wave velocity, micro-resistivity, total porosity, bulk density, and gamma ray logs. Then, a synthetic shear-wave velocity is obtained using these log data with the matrix and secondary porosity data. The statistical approach of correlating a shear-wave velocity with some petrophysical parameters of carbonate reservoirs was also proposed by Eskandari et al. (2003). The authors used five parameters (compressional velocity, neutron porosity, bulk density, gamma ray, and deep resistivity) in a multivariate model to obtain a shear-wave velocity. The correlation coefficient of this methodology was approximately 0.94.

Another approach of shear-wave velocity prediction using fuzzy logic, neuro-fuzzy, and artificial neural network (ANN) techniques was presented by Rezaee et al. (2007). These researchers successfully utilized a back propagation ANN approach which takes input parameters in a network and computes a difference between a desired output and calculated one. Then, the error is back propagated to obtain the optimal weights. The training iterations stop when calculated and desired outputs are in a close proximity. Rezaee et al. (2007) obtained good agreement between outputs utilizing these three methodologies validating the feasibility of utilizing fuzzy logic, neuro-fuzzy, and ANN in shear-wave velocity prediction in carbonate
formations.

To obtain shear-wave velocity data in the 10 wells where the shear data was missing, Techlog software package (the Schlumberger product) was utilized. This software provides an ANN tool for the user similar to the one described by Rezaee et al. (2007). Also, Techlog has a good control for a synthetic-log quality. Each inter-fault block of the West Kazakhstan Field has a well with DSI data. These wells are key wells to provide the input data and quality control for the synthetically derived shear-wave velocities ($V_s$). Key wells in each inter-fault system were used to validate and train the Techlog ANN tool and to obtain the synthetic $V_s$ of the wells in the same block area. The primary seven petrophysical parameters (bulk density, compressional velocity, porosity, gamma ray, clay volume, and photoelectric factor) were utilized in Techlog ANN to create synthetic $V_s$ (see Figure 4.6).

![Figure 4.6](image_url) Input data for ANN and obtained synthetic shear velocity. Track 1 is a measured depth in m; Track 2 is bulk density in $g/cm^3$; Track 3 is compressional velocity in ft/sec; Track 4 is gamma ray in gAPI; Track 5 is neutron porosity in %; Track 6 is photoelectric factor in b/e; Track 7 is porosity in %; Track 8 is clay volume in fraction; Track 9 is obtained synthetic shear velocity in ft/sec; Track 10 is quality control for the obtained synthetic shear velocity, blue color is a good quality indication, and red one is a poor quality indication.
In several of the wells, photoelectric factor data was also missing. Therefore, only six parameters were used in those wells. Even though the six mentioned petrophysical parameters are sufficient to derive a reliable synthetic \( V_s \) (see Figure 4.7), it was found that the photoelectric factor enhances \( V_s \) estimation, probably, due to a better lithology capture.

Figure 4.7  Input data and synthetic shear velocity using ANN. The obtained synthetic shear velocity is in good agreement with measured one even with missing photoelectric factor data. Track 1 is a measured depth in m; Track 2 is bulk density in \( g/cm^3 \); Track 3 is compressional velocity in ft/sec; Track 4 is porosity in %; Track 5 is gamma ray in gAPI; Track 6 is clay volume in fraction; Track 7 is measured shear velocity (black line) and synthetic shear velocity (blue line), both in ft/sec; Track 8 is quality control for the obtained synthetic shear velocity, blue color is a good quality indication, and red one is a poor quality indication.

Static elastic moduli are preferred over moduli obtained using dynamic approaches (Eissa and Kazi, 1988). This preference is based on the theory of the pseudo-static behavior of rock. Therefore, many studies were conducted to correlate these two moduli. One might find a scatter
of dynamic to static moduli ratio in the literature. Analysis of the literature of a dynamic to static modulus correlation was briefly discussed in the following paragraph.

- The dynamic Young’s modulus is typically greater than the static Young’s modulus.
- The dynamic Poisson’s ratio is generally lower than the static one, and finding a correlation between these two is a challenging task due to the typically lower resolution of lateral deformation measurements in calculating the radial strains.
- The ratio between the dynamic and static moduli approaches typically to unity as the confining pressure increases.

The log based measurements are in the kilohertz range while the physical loading on the wellbore, under the in-situ conditions, is pseudo-static (Tutuncu et al., 1992; Judzis et al., 2009). In order to calibrate a dynamic to static elastic modulus correlation with confidence, it is necessary to perform core measurements in a laboratory under in-situ stress conditions.

There have been no core measurements to obtain the formation mechanical properties in the West-Kazakhstan Field. Therefore, a review of the relevant literature in static to dynamic modulus correlations was performed. The specific interests for our investigation for the literature search were confining pressures during an experiment, porosity, presence of microcracks, and lithology of core plugs. Moreover, Tutuncu et al. (1994) emphasized, the significance of the measurement frequency, strain amplitude, clay presence, amount and type of pore fluid as the causes of the discrepancy between the static and dynamic elastic moduli in addition the factors described above.

Cheng and Johnston (1981) measured the static and dynamic bulk moduli (K_s and K_d) of the Bedford limestone (12% porosity), Westerly granite (0.9% porosity), Ammonia tanks tuff (6% porosity), Colorado oil shale, Berea sandstone (18% porosity) and Navajo sandstone (16% porosity) at pressures from atmospheric to 2-3 kilobars. For both sandstones and granite K_s/K_d varied from 0.5 (at atmospheric pressure) and close to 1.0 (at 2 kilobars pressure). K_s/K_d for limestone was close to 1 with a high uploading pressure, but it was reduced with the low pressure in an unloading mode. For the oil shale, with few microcracks, K_s/K_d was relatively constant (about 0.7) at various pressures.
King (1983) reported measurement of the ratio of dynamic to static Young’s moduli \((E_d/E_s)\) for biotite schist specimens. These specimens were separated into two groups: with microcracks and without microcracks. The matrix porosity of specimens was in a range of 1-1.8\%. The static modulus was obtained under uniaxial stress that was increased to a maximum of 35 MPa. The following relationship for microcrack-free specimens was obtained:

\[
E_s = 1.263 \times E_d - 29.5, \tag{4.8}
\]

where Young’s moduli are in GPa.

Later, Montmayour and Graves (1986) predicted a correlation between \(E_d\) and \(E_s\) for consolidated and unconsolidated sandstones with and without microcracks. For the biaxial test, the confining pressure approached to a maximum of 34.5 MPa. The correlation of the static to corrected dynamic Young’s moduli \((E_s/E_{dc})\) for stress-cycled sandstone specimens was expressed in Equation 4.9.

\[
\frac{E_s}{E_{dc}} = 0.81 + 2 \times 10^{-4} \times P, \tag{4.9}
\]

where both the external stress \((P)\) and moduli are in psi.

The obtained relationship between Young’s modulus ratio and applied stress in this study is illustrated in Figure 4.8. From the plot, it is evident that the modulus ratio for dolomite and limey-sandstone approaches to the value close to unity with the increase of the differential stress.

A general relationship between static and dynamic Young’s moduli was obtained by Heerden (1987). The test specimens in the study were norite, magnetite, and different sandstones. The value of \(E_s\) for these specimens varied in the range of 7-150 GPa. Heerden (1987) reported the correlation for the specimens under different incremental uniaxial stresses (maximum 40 MPa). The correlation is expressed as follows:

\[
E_s = a \times E_d^b, \tag{4.10}
\]

where \(a\) and \(b\) are stress dependent parameters, and Young’s moduli are in GPa.
Eissa and Kazi (1988) analyzed available studies of static to dynamic Young’s moduli correlations for different rocks. They reported that the main reasons for the discrepancy in static to dynamic Young’s moduli correlations are related to the possible experimental errors in determining static modulus and non-linear elastic behavior of a specimen. The authors noted that generally the dynamic Young’s modulus is higher than the static one. However, with increase of modulus of elasticity this difference reduces, and static and dynamic moduli ratio approaches to unity. From their analysis Eissa and Kazi (1988) derived the two following equations:

\[ E_s = 0.74 \times E_d - 0.82 \]  \hspace{1cm} (4.11)

\[ \log_{10} E_s = 0.02 + 0.77 \times \log_{10}(\rho \times E_d), \]  \hspace{1cm} (4.12)

where Young’s moduli are in GPa, and \( \rho \) (bulk density) is in g/cm\(^3\).

According to Tutuncu and Sharma (1992), the Young’s modulus obtained from ultrasonic laboratory measurements can be 1-6 times higher than the Young’s modulus under static conditions with the same stress conditions. Also, in the same study Tutuncu and Sharma
compared these two Young’s moduli with the log derived moduli that was measured at 20 KHz. The outcome of these experiments on the tight gas sandstone core samples from the Travis Peak Formation from East Texas was $E_{\text{ultrasonic}} > E_{\text{sonic}} > E_{\text{static}}$. Experimental and modeling results also showed that at high overburden stresses values static and dynamic Young’s modulus approaches each other due to crack closures (Tutuncu and Sharma, 1992).

Differences between the static and dynamic elastic moduli of Calcare Massiccio mudstone-limestone was studied by Ciccotti and Mulargia (2004). The porosity of this rock is in the range of 3-7%. Uniaxial stress was applied to obtain static elastic moduli. According to experimental results, the dynamic Young’s modulus was $81 \pm 5$ GPa, and the dynamic Poisson’s ratio was $0.28 \pm 0.02$. The static Young’s modulus was $77 \pm 1.5$ GPa, while the static Poisson’s ratio was in the range of 0.30-0.43. Ciccotti and Mulargia (2004) noted that the static Poisson’s ratio is not constrained. Therefore, the dynamic Poisson’s ratio values associated with a frequency close to $10^{-3}$ would better represent the static values. These authors found that the difference between the static and dynamic elastic moduli was within 10%. They reported that this result is an agreement with the data for brittle rocks obtained from Eissa and Kazi (1988). It should be noted that the lithology, porosity, and dynamic elastic moduli in the study of Ciccotti and Mulargia (2004) are very close to the parameters in the West Kazakhstan Field.

Later, Olsen and Fabricius (2006) compared the static and dynamic Young’s moduli of North Sea chalk. They found that the dynamic Young’s modulus is 1.3-5 times higher than the statically measured Young’s modulus. There might be a few reasons for this discrepancy between the static and dynamic Young’s moduli. The core sample, taken from outcrops, had a high porosity (about 44%). Also, the confining pressure used in the experiment was only 0.5 MPa. Another correlation between the static and dynamic Young’s moduli was derived for relatively high porosity (up to 23.3%) sandstone specimens (Balin, 2001). Balin (2001) reported that the dynamic undrained Young’ modulus was 2-3 times higher than the static one with the confining pressure of 22.2 MPa. The derived relationship from that study is as follows:

$$E_s = 0.39 \times E_d,$$  \hspace{1cm} (4.13)

where the Young’s moduli are in GPa.
Research relevant to our study field was conducted by Al-Shayea and Khan (2001). Rock type for that study was limestone with a porosity of 5.4%. These authors reported that the ratio of static to dynamic elastic moduli was about unity with confining pressure between 102-107.5 MPa. They explained the reported results with a high UCS of specimens. These lithology and parameters in the study of Al-Shayea and Khan (2001) are very similar to the data in the West Kazakhstan Field.

An unpublished relationship between the static to dynamic Young’s modulus ratio to the dynamic bulk modulus was reported by Santos and Ferreira (2010). This relationship, intended for carbonate formations, is as follows:

\[
\frac{E_s}{E_d} \approx \frac{K_d[\text{GPa}]}{79.6},
\]

(4.14)

where \(K_d\) is a dynamic bulk modulus in GPa, and 79.6 is the assumed carbonate grain bulk modulus also in GPa. When the dynamic bulk modulus reaches the value of the grain bulk modulus (79.6 GPa) for carbonate rocks, porosity would be significantly reduced. Therefore, the static Young’s modulus would approach the dynamic one.

Equation 4.14 might be applicable for other minerals with an appropriate substitution of the mineral bulk modulus. In this study Equation 4.14 was utilized with the different mineral bulk moduli. The mineral bulk moduli used in this study are listed in Table 4.4.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Mineral bulk modulus, GPa</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>70.15</td>
<td></td>
</tr>
<tr>
<td>Dolomite</td>
<td>73</td>
<td></td>
</tr>
<tr>
<td>Clay (illite and kaolinite)</td>
<td>36.7</td>
<td>Wang et al. (2001)</td>
</tr>
<tr>
<td>Quartz</td>
<td>37.9</td>
<td></td>
</tr>
</tbody>
</table>

An average of Voigt’s upper bound and Reuss lower bound values (Mavko et al., 2003) was utilized in a mixed lithology environment to obtain a grain bulk modulus. A histogram of the
obtained Young’s moduli ratio is illustrated in Figure 4.9. As can be seen, most of the values are in the range of 1-1.3 which is in agreement with the reviewed literature. Also, this range of the ratio is reasonable in a low porosity and high stress regime media as in the West Kazakhstan Field.

![Histogram of dynamic to static Young’s moduli ratio in the interval 2730-5150 m, Well A.](image)

The obtained Young’s modulus ratio was attempted in determining the static Poisson’s ratio (see Figure 4.10). From Figure 4.10 it is evident that this approach might be feasible for the static Poisson’s ratio case; however, the right tale of the curve shows unphysical values for Poisson’s ratio as the upper limit for Poisson’s ration is 0.5.
Figure 4.10  Histogram of the obtained static Poisson’s ratio in the interval 2730-5150 m, Well A.

Figure 4.11  Histogram of the log-derived dynamic Poisson’s ratio in the interval 2730-5150 m, Well A.
These errors might be caused by the possible errors involved in measurements of the shear velocity in the field due to the presence of washouts. Also, the errors might be caused by this dynamic to static Poisson’s ratio correlation approach. A histogram of dynamic Poisson’s ratio is illustrated in Figure 4.11. Further core sample may demonstrate a level of accuracy of the assumptions used. Meanwhile, the aforementioned dynamic to static modulus correlation is utilized for this study with the cutoff at Poisson’s ratio of 0.45 (red dotted line shown in Figure 4.10).

4.4.2 Uniaxial Compressive Strength

Uniaxial compressive strength (UCS) is a critical parameter in both constraining the maximum horizontal stress magnitude and obtaining an appropriate rock-failure envelope for the formation of interest. Typically, this parameter is obtained from laboratory core measurements under uniaxial loading stress conditions. Core samples should represent various facies. Then, the obtained UCS is usually correlated to the different petrophysical and geomechanical parameters such as compressional velocity, porosity, clay volume, Young’s modulus. This type of correlation may enhance a prediction of UCS from the well-log derived properties without expensive and time-consuming laboratory experiments. It should be admitted that this prediction would be inherent only for the field it was derived from, and this prediction or correlation does not have to be assumed directly applicable to other fields. However, correlations derived in the regions geographically close to the field of study with similar tectonic history, stress regime, lithology, and petrophysical properties might be applicable to obtain initial constraints of UCS. There is a high possibility that the empirically obtained UCS values would contain some errors compared to the actual one. Definitely, further validation and calibration using laboratory measurement data should be applied. In this study, since core samples are not available yet, the empirical correlations from the literature review were used to constrain UCS in the West Kazakhstan Field.

Santos and Ferreira (2010) presented a summary of UCS correlations from the literature. A summary of the formation strength correlations used in this study are presented in Equations 4.15 thru 4.29. In all of these UCS equations units for Young’s modulus (E), bulk density (ρ), compressional velocity (\(V_p\)) are shown in brackets. Porosity (\(\varnothing\)) is in fraction.
Equation 4.15 was derived for carbonate formations. Equation 4.16 was for igneous and metamorphic rocks of the Canadian Shield (King, 1983). Equation 4.17 was obtained using several hundred core measurements on sandstone, shale, limestone, and dolomite specimens. Golubev and Rabinovich (1976) derived the UCS correlation reported in Equation 4.19. Equation 4.20 was derived for limestone rocks with UCS in the range of 10-300 MPa. For dolomite rocks,
with the UCS in the range of 60-100 MPa, Equation 4.21 might be applicable. Rzhevsky and Novik (1971) derived Equation 4.22 for the Korobcheyev carbonate deposit in Russia. Cheng (2004) presented Equation 4.23 for a Middle East rock with the porosity and UCS in the range of 0.05-0.20 and 10-300 MPa. Cheng (2004) also reported Equation 4.24 for rocks with the porosity and UCS ranges of 0-0.20 and 10-300 MPa. Smorodinov (1970) derived Equation 4.25 for a group of carbonate rocks in Russia. Another correlation for carbonate rocks was expressed in Equation 4.26 (Farquhar et al., 1994). Equation 4.27 was obtained from the wide range of samples from the North Sea area with different mineralogy, porosity, and heterogeneity. Ameen et al. (2009) reported Equations 4.28 (dolomites) and 4.29 (limestone) for the Ghawar Field.

Another set of the empirical relationships between UCS and other petrophysical parameters for sandstones, shales, and carbonates was summarized by Zoback (2010). Among those equations, only equations derived for low porosity, compacted, and strong rocks are considered for this study. The selected group of equations is listed in Equations 4.30 thru 4.35.

\[
UCS_{[MPa]} = 42.1 \exp(1.9 \times 10^{-11} \times \rho_{[kg/m^3]} \times V_p^{2} \ [m/s])
\] (4.30)

\[
UCS_{[MPa]} = 277 \exp(-10\Phi)
\] (4.31)

\[
UCS_{[MPa]} = 0.0528 \times E_{[MPa]}^{0.712}
\] (4.32)

\[
UCS_{[MPa]} = 1.001 \times \Phi^{-1.143}
\] (4.33)

\[
UCS_{[MPa]} = 0.4067 \times E_{[MPa]}^{0.51}
\] (4.34)

\[
UCS_{[MPa]} = 0.0024 \times E_{[MPa]}^{0.34}
\] (4.35)

where porosity in Equations 4.31 and 4.33 are in fraction. Equation 4.30 was derived for consolidated sandstones in Australia with the porosity in the range of 0.05-0.12 and UCS above 80 MPa. Equation 4.31 represents wide range porosity (0.002-0.33) sandstones with the UCS between 2-360 MPa. For strong and compacted shales Equation 4.32 might be applicable. Also, another UCS correlation (Equation 4.33) for low porosity and high strength shales was reported by Lashkaripour and Dusseault (1993). Equations 4.34 and 4.35 were derived for the same rocks as in Equations 4.20 and 4.21 but with different units of the Young’s modulus.
The West Kazakhstan Field is represented with limestone, dolomite, sandstone and shale facies. To empirically obtain UCS in the study field, Equations 4.24 (for dolomites), 4.31 (for sandstone), 4.32 (for shale) and 4.34 (for limestone) were utilized. The curve of the calculated UCS values for Well A is illustrated in Figure 4.12 (red curve). The calculated UCS should be checked through the quality control process by measuring the actual UCS in laboratory conditions if core samples are made available in the future.

4.4.3 Tensile Formation Strength

Tensile strength of rock is an important parameter in calculating and constraining the minimum and maximum horizontal stresses. Typically, for unconsolidated formations tensile strength is assumed to be zero. That assumption is based on the disturbance of an intact condition of rock by bit penetration. However, in highly compacted and strong formations under high in-situ stresses, as in our study field, the tensile strength might be non-zero. To obtain a reliable tensile strength value, Brazilian laboratory measurements should be conducted. In the absence of the core measurement data, the tensile strength is usually estimated at 10-12% of the UCS for all facies. This approach might be somewhat misleading considering that tensile strength is typically impacted by the lithology type, compaction level, lamination orientation, and presence of microcracks (Hobbs, 1964). The relationship between UCS and tensile strength for different rock types was reported by Hobbs (1964). Hobbs (1964) also investigated the difference of tensile strength when a load was applied at different angles to laminations. Results of the Hobbs’ experiments are shown in Tables 4.5 and 4.6.

In Tables 4.5 and 4.6, it is evident that most of massive rocks such as limestone and sandstone have higher ratio of the tensile to UCS than in the laminated rocks. Therefore, it is reasonable to use 0.15 ratio for massive and strong rocks (dolomite, limestone, and sandstone) and ratio of 0.05 for shale formations in our study field (see Figure 4.12). A lower boundary of the $S_{h_{max}}$ and $S_{h_{min}}$ was estimated when the tensile strength at the wellbore was taken as zero.
Figure 4.12 Calculated uniaxial compressive and tensile strength for Well A.
Table 4.5  Relationship between Tensile Strength and UCS for Massive Rocks (Modified from Hobbs, 1964)

<table>
<thead>
<tr>
<th>Rock</th>
<th>Tensile strength, psi</th>
<th>UCS, psi</th>
<th>Ratio of tensile strength to UCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portland Limestone</td>
<td>2610±90</td>
<td>6010±510</td>
<td>0.43</td>
</tr>
<tr>
<td>Ormonde Sandstone 3</td>
<td>2780±30</td>
<td>11250±230</td>
<td>0.24</td>
</tr>
<tr>
<td>Ormonde Sandstone 4</td>
<td>3350±70</td>
<td>11720±320</td>
<td>0.28</td>
</tr>
<tr>
<td>Darley Dale Sandstone</td>
<td>3510±120</td>
<td>13120±560</td>
<td>0.26</td>
</tr>
<tr>
<td>Babbington Mudstone</td>
<td>5100±460</td>
<td>7260±550</td>
<td>0.70</td>
</tr>
<tr>
<td>Bulwell Limestone</td>
<td>5260±180</td>
<td>20670±890</td>
<td>0.25</td>
</tr>
<tr>
<td>Breedon Limestone</td>
<td>5620±390</td>
<td>20730±2770</td>
<td>0.27</td>
</tr>
<tr>
<td>Bilsthorpe Ironstone</td>
<td>6420±650</td>
<td>27650±2600</td>
<td>0.23</td>
</tr>
<tr>
<td>Pennant Sandstone</td>
<td>9520±120</td>
<td>24310±1430</td>
<td>0.39</td>
</tr>
</tbody>
</table>

Table 4.6  Relationship between Tensile Strength and UCS for Laminated Rocks (Modified from Hobbs, 1964)

<table>
<thead>
<tr>
<th>Rock</th>
<th>Tensile strength, psi</th>
<th>UCS, psi</th>
<th>Ratio of tensile strength to UCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donisthorpe Siltstone 2</td>
<td>2380±120</td>
<td>14020±1370</td>
<td>0.16</td>
</tr>
<tr>
<td>Ormonde Sandstone 3</td>
<td>1150±70</td>
<td>10320±710</td>
<td>0.11</td>
</tr>
<tr>
<td>Ormonde Siltstone</td>
<td>1260±110</td>
<td>10010±1660</td>
<td>0.12</td>
</tr>
<tr>
<td>Ormonde Siltstone</td>
<td>1970±120</td>
<td>11330±280</td>
<td>0.17</td>
</tr>
<tr>
<td>Ormonde Siltstone</td>
<td>1190±370</td>
<td>12520±630</td>
<td>0.09</td>
</tr>
<tr>
<td>Ormonde Siltstone</td>
<td>1770±270</td>
<td>12390±280</td>
<td>0.14</td>
</tr>
</tbody>
</table>

4.4.4  Angle of Internal Friction and Friction Coefficient

The literature relating the angle of internal friction to petrophysical parameters is quite limited. Even weak formations can have a high friction angle (Zoback, 2010), and the most appropriate approach is to obtain friction angle is when a uniaxial compressive strength test is conducted. Again, in the absence of core measurements in our study field, internal friction angle was obtained using empirical correlations published in the literature. Zoback (2010) reported the
empirical correlations for shales (Equation 4.36) and shaly sedimentary formations (Equation 4.37) in Equations 4.36 and 4.37.

\[ \Phi = 70 - 0.417 \times GR \] (4.36)

\[ \Phi = \tan^{-1}\left(\frac{78 - 0.4 + GR}{60}\right) \] (4.37)

where internal friction angle (\( \Phi \)) is in degrees, and gamma ray (GR) is in gAPI. In the intervals where the volume of clay is greater than 15 \%, Equation 4.36 was utilized.

Knowing the value of the internal friction angle, it is possible to obtain friction coefficient using Equation 4.38.

\[ \mu_i = \frac{1 + \sin \Phi}{1 - \sin \Phi} \] (4.38)

where \( \mu_i \) is friction coefficient. A histogram for the calculated coefficient of internal friction is illustrated in Figure 4.13.

![Figure 4.13 Histogram of the log-derived coefficient of internal friction values.](Image)
Since Equations 4.36 and 4.37 are based on gamma ray readings, the correlation between the clay volume and the coefficient of internal friction is evident as in Figure 4.14. The formation with less than 20% clay content has the coefficient of internal friction in the range of 0.43–0.7. Moreover, in the high shale containing intervals, this range is lower (between 0.15 – 0.4). Typically, if the information on the existence or absence of wellbore breakouts and tensile failure is available, the coefficient of internal friction is not essential on determining the principal horizontal stress magnitudes. However, it is an important parameter in constraining of the rock failure envelope.

### 4.4.5 Biot’s Coefficient

Biot’s coefficient, which is also a stress dependent parameter, was used in a numerical wellbore-stability model. Since no laboratory measurement data for Biot’s coefficient was
available for this study, a possible range of Biot’s coefficient for this study was taken as 0.6-1 with the mean value of 0.8. Analysis of the planned XLOT analysis in the study field might be helpful in further constraining this parameter.

4.5 Orientations of the Principle Horizontal Stresses

One of the important factors affecting wellbore failure is an orientation of the principle horizontal stresses (Barton et al. 1997). According to Barton et al. (1997), breakouts will be observed if the hoop stress is most compressive at the direction of the minimum horizontal stress and when the stress concentration overwhelms the rock strength. By contrast, the circumferential stress has the least compression at the orientation of the maximum principle horizontal stress, causing the drilling-induced fractures. Therefore, the orientation of the wellbore breakouts and tensile fractures is the clear indication of the horizontal stress azimuths, assuming that the well is vertical. This approach was utilized using the available FMI log data for the Well A in the 8 ½ inch section. The interpreted interval is 3500-5160 m. The FMI log was scanned for visible drilling induced tensile fractures and breakouts (Figures 4.15 and 4.16).

![FMI log with drilling induced tensile and shear fractures.](image)

Figure 4.15  FMI log with drilling induced tensile and shear fractures.
The results obtained are presented in Tables 4.7 and 4.8. It can be observed that the orientation of the principle horizontal stresses is relatively consistent along the interval of interest.

![Figure 4.16  FMI log with breakouts and caliper fluctuation.](image)

Table 4.7  The Orientation of Drilling-Induced Tensile Fractures

<table>
<thead>
<tr>
<th>Depth, m</th>
<th>Tensile Azi 1, °</th>
<th>Tensile Azi 2, °</th>
<th>Shmin 1, °</th>
<th>Shmin 2, °</th>
</tr>
</thead>
<tbody>
<tr>
<td>3597.5</td>
<td>135</td>
<td>315</td>
<td>225</td>
<td>405</td>
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<tr>
<td>3604</td>
<td>135</td>
<td>315</td>
<td>225</td>
<td>405</td>
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<tr>
<td>3612</td>
<td>135</td>
<td>315</td>
<td>225</td>
<td>405</td>
</tr>
<tr>
<td>3630</td>
<td>135</td>
<td>315</td>
<td>225</td>
<td>405</td>
</tr>
<tr>
<td>3681</td>
<td>135</td>
<td>250</td>
<td>192.5</td>
<td>372.5</td>
</tr>
<tr>
<td>4216</td>
<td>135</td>
<td>325</td>
<td>230</td>
<td>410</td>
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<td>4271</td>
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<td>325</td>
<td>230</td>
<td>410</td>
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<td>4432</td>
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<td>410</td>
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<td>4446</td>
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<td>325</td>
<td>230</td>
<td>410</td>
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<td>4461</td>
<td>135</td>
<td>325</td>
<td>230</td>
<td>410</td>
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<td>4472</td>
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<td>410</td>
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<tr>
<td>4494</td>
<td>145</td>
<td>330</td>
<td>237.5</td>
<td>417.5</td>
</tr>
<tr>
<td>4503</td>
<td>145</td>
<td>325</td>
<td>235</td>
<td>415</td>
</tr>
<tr>
<td>4906</td>
<td>135</td>
<td>320</td>
<td>227.5</td>
<td>407.5</td>
</tr>
<tr>
<td>4950</td>
<td>145</td>
<td>320</td>
<td>232.5</td>
<td>412.5</td>
</tr>
</tbody>
</table>
Table 4.8  The Orientation and Width of Breakouts

<table>
<thead>
<tr>
<th>Depth, m</th>
<th>Breakout Azi 1, °</th>
<th>Breakout Azi 2, °</th>
<th>Width Azi 1, °</th>
<th>Width Azi 2, °</th>
<th>Aver. Width, °</th>
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<tbody>
<tr>
<td>3598</td>
<td>N/A</td>
<td>205-280</td>
<td>N/A</td>
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<tr>
<td>3616.5-3618.4</td>
<td>45-90</td>
<td>225-270</td>
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<td>3622-3624.4</td>
<td>30-60</td>
<td>210-240</td>
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<td>30</td>
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<tr>
<td>3654-3655</td>
<td>25-55</td>
<td>210-240</td>
<td>83</td>
<td>100</td>
<td>91.5</td>
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<td>15-45</td>
<td>185-225</td>
<td>30</td>
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<td>35</td>
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<td>4852</td>
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<td>135-185</td>
<td>97</td>
<td>50</td>
<td>73.5</td>
</tr>
</tbody>
</table>

4.6  Magnitudes of the Minimum and Maximum Horizontal Stresses

Magnitudes of the minimum horizontal stress are essential parameters in the determination of a stress regime. According to Oort et al. (2001), the most accurate value of the minimum horizontal stress corresponds to the fracture closure pressure during the Extended Leak-off Tests (XLOT). Since there are no available XLOT data in the West Kazakhstan Field, the Eaton method was used to calculate the extended fracture propagation pressure (Mitchell, 1995), that was assumed to be equal to the magnitude of the minimum horizontal stress (Equation 4.39).

\[ Sh_{min} = \left( \frac{\vartheta}{1-\vartheta} \right) \times (S_{ov} - \alpha \times P_p) + \alpha \times P_p + T_s, \]  

(4.39)

where \( \vartheta \) is Poisson’s ratio, and \( \alpha \) is Biot’s coefficient, to be 0.8. The minimum horizontal stress \( (Sh_{min}) \), overburden stress \( (S_{ov}) \), pore pressure \( (P_p) \), and rock tensile strength \( (T_s) \) are in psi.

Unless FMI log and multi-caliper log data are available, the determination of the maximum horizontal stress \( (SH_{max}) \) magnitude is often a highly challenging task. Peska and
Zoback (1995) described two methods of utilizing the borehole image and caliper data to obtain magnitudes of the \( SH_{max} \). The methods are based on the identification and application of wellbore tensile cracks and breakouts using the following equations (Zoback, 2010).

Equation 4.40 was utilized to constrain the magnitude of the \( SH_{max} \) using wellbore tensile fractures.

\[
SH_{max} = 3 \times Sh_{min} - 2 \times P_p - \Delta P - T_z, \tag{4.40}
\]

where \( \Delta P \) is the difference between drilling ECD and pore pressure in psi. A width of breakouts were used in Equation 4.41 to constrain the magnitude of the \( SH_{max} \).

\[
SH_{max} = \frac{\left(UCS + 2 \times P_p + \Delta P + T_z \right) - Sh_{min} \times \left(1 + 2 \times \cos 2\theta_b\right)}{1 - 2 \times \cos 2\theta_b}, \tag{4.41}
\]

where \( \Delta P \) is the difference between the wellbore pressure (swab pressure) and pore pressure (in psi), and \( 2\theta_b \) equals \( \pi - \omega_b \). \( \omega_b \) is the width of a breakout in degrees. The UCS is also in psi.

Moos and Zoback (1990) described in detail the approach for constraining the uncertainty of the maximum horizontal stress magnitude obtained using Equations 4.40 and 4.41. The approach is based on the determination of allowable stress conditions (stress polygon) in which tensile failures and/or breakouts can occur. The parameters required to build the stress polygon are as follows:

- coefficient of internal friction
- pore pressure
- ECD
- surge pressure
- magnitudes of overburden stress
- magnitude of minimum horizontal stress

An example of using the stress polygon for constraining the in situ stress magnitudes is shown in Figures 4.17, 4.18 and 4.19.

Note that in this study most of the calculated \( SH_{max} \) values from Equations 4.39 and 4.40 are in the range of \( SH_{max} \) constrained using the stress polygon approach. The uncertainty of the \( SH_{max} \) magnitude would be less in intervals where both breakouts and tensile fractures occurred.
As Equation 4.39 is sensitive to a breakout width value, it is critical to have borehole image data with a good quality to successfully implement this approach. The misinterpretation of the breakout width by +/- 20° might result in the fluctuation of the $SH_{max}$ magnitudes by 1 – 1.5 g/cc.

![Figure 4.17 Stress polygon at the depth 4408 m with 3 different stress regime areas. Since $SH_{max}$ magnitude is equal or higher than $Sh_{min}$ magnitude, no stress state can occur below blue diagonal.](image)

Wellbore breakout and tensile failure events were plotted as illustrated in Figure 4.20. It is evident that the stress regime in the entire interval is in the strike-slip regime. Tensile wellbore-failure events are additional validations of this stress regime interpretation. On the other hand, below 4300 m, the $SH_{max}$ magnitude calculated using wall breakout events is close to the overburden stress magnitude, which might be the transition from the strike-slip stress regime to the normal faulting condition. The absence of tensile failures on FMI images also implies that the stress state below 4300 m is close to the normal faulting. It is interesting to note that the Devonian faults located below 4800 m are near-vertical. Typically, near-vertical faults correspond to strike-slip regime. However, due to the increase of the overburden stress over the historical time, the current stress regime below 4300 m is gradually shifting from the strike-slip
Figure 4.18  Stress polygon at the depth 4408 m. Breakouts at all azimuths occur below Line 1. Breakouts at the azimuth of $S_{hmin}$ occur above Line 2.

Figure 4.19  Stress polygon at the depth 4408 m. Line 3 represent the condition of tensile failure occurrence with tensile strength equals to zero. Since no tensile failure was observed at this depth, except breakouts, the possible range of $SH_{max}$ magnitude is constrained by lines 2 and 3.
stress regime to the normal faulting one. Determination of a stress regime at different depths is very critical input data for wellbore-stability numerical models.

Figure 4.20 Magnitude of pore pressure and principle stresses as a function of true vertical depth. Red circles represent pore pressure data from MDT measurements. Blue squares are calculated $SH_{max}$ values using wellbore breakout analysis. Black diamond symbols correspond to the $SH_{max}$ magnitudes obtained from tensile failure interpretations. Black and red lines are $Sh_{min}$ and $SH_{max}$ magnitudes.
CHAPTER 5

NUMERICAL MODELING OF WELLBORE STABILITY

Typically, the magnitudes of the in-situ horizontal stresses and their difference from the overburden stress magnitude are addressed in wellbore-stability analyses using numerical models. The role of stress anisotropy and its dominating influence on the wellbore-stability analysis is well recognized. However, the physicochemical interaction of formation native fluid and the introduced drilling fluid with each other, as well as with the formation temperature alterations induced during drilling, and flow-induced stress effect also have significant impact on the net stress concentrations at the wellbore.

5.1 Modeling of the Stress Effect

Modeling the mechanical stress effect at the wellbore is one of the most common methodologies to identify if the effective stresses around the borehole exceed the compressive strength of the rock. Aadnoy and Looyeh (2011) described in detail the workflow of obtaining the stress state at the wellbore using in-situ principle stresses, inclination and orientation of the well.

First, in-situ stress orientations and magnitudes need to be determined as it is discussed in detail in Chapter 4. The most common procedure for calculating the stress concentration around the wellbore is utilizing the Kirsch equations. To find the stress state at the arbitrarily oriented wellbore, it is necessary to transform in-situ stresses to a new Cartesian coordinate system. Only after this transformation, we can derive the stress state near the vicinity of the wellbore using the Kirsch concept. For the stress transformation, Equation 5.1 is utilized below (Aadnoy and Looyeh, 2011).

\[ \sigma_x = (S_{H_{\max}}\cos^2\varphi + S_{H_{\min}}\sin^2\varphi)\cos^2\gamma + S_{ov}\sin^2\gamma, \]
\[ \sigma_y = S_{H_{\text{max}}} \sin^2 \varphi + S_{h_{\text{min}}} \cos^2 \varphi, \]

\[ \sigma_{xz} = (S_{H_{\text{max}}} \cos^2 \varphi + S_{h_{\text{min}}} \sin^2 \varphi) \sin^2 \gamma + S_{ov} \cos^2 \gamma, \]

\[ \tau_{xy} = \frac{1}{2} (S_{h_{\text{min}}} - S_{H_{\text{max}}}) \sin 2 \varphi \cos \gamma, \] \hspace{1cm} (5.1)

\[ \tau_{xz} = \frac{1}{2} (S_{H_{\text{max}}} \cos^2 \varphi + S_{h_{\text{min}}} \sin^2 \varphi - S_{ov}) \sin 2 \gamma, \]

\[ \tau_{yz} = \frac{1}{2} (S_{h_{\text{min}}} - S_{H_{\text{max}}}) \sin 2 \varphi \sin \gamma, \]

where \( \sigma_x, \sigma_y, \sigma_{xz}, \tau_{xy}, \tau_{xz}, \) and \( \tau_{yz} \) are the transformed stress components (see Figure 5.1). \( \varphi \) is the wellbore azimuth from the direction of \( S_{H_{\text{max}}} \), and \( \gamma \) is the wellbore inclination from the vertical. Both angles are in radians. The y-axis in this transformation is parallel to the plane formed by \( S_{H_{\text{max}}} \) and \( S_{h_{\text{min}}} \).

Figure 5.1  The position of stresses around a wellbore in the rock formation where \((\sigma_y, \sigma_{H}, \sigma_h)\) represents the principle in-situ stress state, and, \((\sigma_x, \sigma_y, \sigma_z)\) and \((\sigma_r, \sigma_\vartheta, \sigma_z)\) represent the stress states at the wellbore in the Cartesian and cylindrical coordinate systems, respectively (Aadnoy and Looyeh, 2011).
The transformation of Equation 5.1 from the Cartesian coordinate system to the cylindrical system results in Equation 5.2, which is the Kirsch equation.

\[
\sigma_r = \frac{1}{2}(\sigma_x + \sigma_y)(1 - \left(\frac{a}{r}\right)^2) + \frac{1}{2}(\sigma_x - \sigma_y)(1 + 3\left(\frac{a}{r}\right)^4 - 4\left(\frac{a}{r}\right)^2) \cos 2\theta + \tau_{xy}(1 + 3\left(\frac{a}{r}\right)^4 - 4\left(\frac{a}{r}\right)^2) \sin 2\theta + \Delta p_w \left(\frac{a}{r}\right)^2, \tag{5.2}
\]

\[
\sigma_\theta = \frac{1}{2}(\sigma_x + \sigma_y)(1 + \left(\frac{a}{r}\right)^2) - \frac{1}{2}(\sigma_x - \sigma_y)(1 + 3\left(\frac{a}{r}\right)^4) \cos 2\theta - \tau_{xy}(1 + 3\left(\frac{a}{r}\right)^4) \sin 2\theta, \tag{5.3}
\]

\[
\tau_{rz} = \tau_{x2}\cos\theta + \tau_{y2}\sin\theta)(1 - \left(\frac{a}{r}\right)^2),
\]

where \(a\) is the radius of wellbore, and \(r\) is the outer radius; \(\theta\) is the wellbore position from the x-axis. \(\Delta p_w\) is the difference between the wellbore pressure and pore pressure and can be expressed as in Equation 5.3:

\[
\Delta p_w = p_w - p_p. \tag{5.3}
\]

At the borehole, when \(r=a\), Equation 5.2 is reduced to Equation 5.4.

\[
\sigma_r = \Delta p_w,
\]

\[
\sigma_\theta = (\sigma_x + \sigma_y - \Delta p_w) - 2(\sigma_x - \sigma_y)\cos 2\theta - 4\tau_{xy}\sin 2\theta,
\]

\[
\sigma_z = \sigma_{zz} - 2\theta(\sigma_x - \sigma_y)\cos 2\theta - 4\theta \tau_{xy}\sin 2\theta, \tag{5.4}
\]

100
\[ \tau_{r\theta} = \tau_{rz} = 0, \]
\[ \tau_{\theta z} = 2(\tau_{yz}\cos\theta - \tau_{xz}\sin\theta). \]

Then, the effective principle stresses at the borehole wall for an arbitrarily oriented well are calculated using Equation 5.5.

\[
\sigma_{t,\text{max}} = \frac{1}{2}(\sigma_{\theta} + \sigma_{z}) + \frac{1}{2}\sqrt{(\sigma_{\theta} - \sigma_{z})^2 + 4\tau_{\theta z}^2},
\]
\[
\sigma_{t,\text{min}} = \frac{1}{2}(\sigma_{\theta} + \sigma_{z}) - \frac{1}{2}\sqrt{(\sigma_{\theta} - \sigma_{z})^2 + 4\tau_{\theta z}^2},
\]
\[
\sigma_{rr} = \sigma_r = \Delta p_w. \tag{5.5}
\]

### 5.2 Modeling of the Chemical Interaction Effect

Since the chemical composition of the water in the pores will potentially be different from the chemical composition of the drilling mud for most of cases, a chemical interaction between drilling mud and formation fluid might take place. This chemical interaction is especially critical when the drilling mud is exposed to the shale intervals drilled. According to Fam and Dusseault (1999), the term shale has a broad definition in the drilling industry. This term includes “all fine-grained sedimentary rocks, with or without fissility, but with some amount of clay minerals present”. If a shale formation contains swelling clay minerals, this formation is considered to be reactive, and a careful mud selection should be conducted to minimize the interaction. Due to a low permeability of shale formations, it is difficult to create a filter cake to prevent chemical-mechanical interactions in these zones. Therefore, water and pressure can penetrate into the shale formation and increase pore pressure (Tutuncu and Mese, 2011). When the pore pressure increases, stress alteration at the wellbore can occur resulting in shale yielding (Fam and Dusseault, 1999). If the mud weight used is not high enough to support the formation fluid pressure, the yielded shale can start sloughing into the wellbore, creating wellbore-stability issues. This shale yielding problem can be avoided by utilizing oil-based mud systems. Due to the capillary phenomena, oil-based mud will not significantly penetrate into the formation. Water-based mud systems can also be optimized if the chemical-interaction
mechanism between the mud filtrate and shale water is properly analyzed, and the resulting additional effects are adequately calculated. In some cases a high mud weight can be the reason for cohesion degradation, which is the rock strength weakening over time due to the formation dehydration effect. Therefore, mud formulation and mud weight optimization is a complex process which requires coupling with the mechanical and chemical components in the wellbore-stability analysis.

When formation is exposed to various fluid types, the shale formation creates an additional pressure called “swelling pressure” that needs to also be included in the mud pressure. The knowledge of the osmotic pressure component would be helpful in understanding the fluid type and composition impact on the stress alteration at the wellbore. Once it is known, a variety of techniques can be used to eliminate or mitigate the influence of the swelling pressure on the drilling performance. According to Chen et al. (2001), the chemical effect due to the difference between the shale water activity and drilling fluid activity can be accepted as an equivalent hydraulic potential. A chemical modeling has been implemented in this study in order to estimate the impact of chemical phenomena on the alteration of hoop and axial stresses near the vicinity of the wellbore.

The calculation of the osmotic pressure can be helpful in determining the chemical-interaction impact on the stress alteration at the wellbore. Using equations in the literature (Chen et al., 2001; Fam and Dusseault, 1998) and equations provided during the Well Integrity class (Tutuncu, 2010(a)), the numerical equations for the osmotic pressure and its effect on the effective stresses acting at the borehole are formulated as follows:

\[
\sigma_r' = 0, \\
\sigma_\theta' = \alpha \frac{1-2\theta}{1-\theta} \Delta \Pi, \\
\sigma_z' = \alpha \frac{1-2\theta}{1-\theta} \Delta \Pi,
\]

where \( \sigma_r' \), \( \sigma_\theta' \) and \( \sigma_z' \) are the alteration of radial, hoop and axial stresses due to the introduction of the osmotic pressure. \( \alpha \) is the Biot’s coefficient, and \( \theta \) is Poisson’s ratio, which are stress-dependent values. \( \Delta \Pi \) is the osmotic pressure.
The osmotic potential acts in a similar way to the excess pore pressure and can be expressed by Equation 5.7 (Tutuncu, 2010 (a)):

\[ \Delta \Pi = I_m \left( \frac{RT_o}{V_w} \right) \ln \frac{a_{w,df}}{a_{w,sh}}, \] 

(5.7)

where \( I_m \) is a reflection coefficient which characterizes membrane efficiency. \( I_m \) is a dimensionless parameter and ranges from 0 to 1. \( R \) is the universal gas constant and equals 8.314 \( \frac{J}{K \cdot mole} \). \( T_o \) is the absolute temperature, \( K \). \( V_w \) is the molar volume of the water (\( V_w = 18.104 \ m^3 \)). \( a_{w,df} \) and \( a_{w,sh} \) are chemical activities of the drilling fluid and shale pore water respectively. The chemical activity of the fresh water equals 1, and the chemical activity of the salt water is less than 1.

Adding Equation 5.6 to Equation 5.4 gives a coupled numerical model that considers both mechanical and chemical variations (Equation 5.8).

\[ \sigma_r = \Delta p_w, \]

\[ \sigma_\theta = (\sigma_x + \sigma_y - \Delta p_w) - 2(\sigma_x - \sigma_y)\cos2\theta - 4\tau_{xy}\sin2\theta + \alpha \frac{1-2\theta}{1-\theta} \Delta \Pi, \]

\[ \sigma_z = \sigma_{zz} - 2\theta(\sigma_x - \sigma_y)\cos2\theta - 4\theta\tau_{xy}\sin2\theta + \alpha \frac{1-2\theta}{1-\theta} \Delta \Pi, \] 

(5.8)

\[ \tau_{r\theta} = \tau_{rz} = 0, \]

\[ \tau_{\theta z} = 2(\tau_{yz}\cos\theta - \tau_{xz}\sin\theta). \]

Typically, a reflection coefficient of water as well as chemical activities of drilling fluid and formation pore water is obtained from laboratory measurements. No chemical activity measurements were conducted in the West Kazakhstan Field. Based on personal communications with Sergei Medentsev (2012, personal communication), a MI-Swaco Schlumberger company representative, the water chemical activity of the NaCl/polymer and KCl/polymer type drilling fluids were constrained in the West Kazakhstan Field. The \( a_w \) for the KCl/polymer muds in the field of study would be around 0.94-0.96. For the NaCl/polymer muds,
would be in the range of 0.75-0.80. To check the feasibility of these assumptions and to constrain values of the unknown parameters in Equation 5.7, a literature review was performed.

Mody and Hale (1993) evaluated the alteration of pore pressure in the Pierre shale ($a_{sh} = 0.91$) due to the introduction of CaCl$_2$, NaCl, and KCl drilling fluids. The $a_w$ for these fluids ranged between 0.82-0.96. Van Oort et al. (1996) reported experimental results on the Eocene shale for various drilling fluid types. These authors found that $a_{w,sh}$ of the Eocene shale was about 0.84. The water activity of the KCl/polymer fluid was 0.93, while the water activity of the 25% CaCl$_2$ fluid was about 0.73. Simpson and Dearing (2000) conducted laboratory experiments in quantifying the diffusion osmosis on the Oligocene shale cores. This shale had a water activity of 0.91. The water activity of the introduced CaCl$_2$ brine with a density of 1.23 g/cm$^3$ (10.3 ppg) was 0.72.

Zhang et al. (2004) conducted a new gravimetric swelling test for evaluating the shale and drilling fluid compatibility. Arco shale ($a_{w,sh} = 0.78$) and Pierre I ($a_{w,sh} = 0.98$) shale samples were used for this test. While the Pierre I shale is an outcrop sample, the Arco shale has been cored from the depth at about 15000 feet and was considered to be an acceptable analog for the West Kazakhstan Field shales. Among the few types of the fluids introduced to the shales in this test, KCl and NaCl fluids are in particular interest for this research. The water activity of the KCl was obtained as 0.85, and for NaCl 0.755. Another test on the Gulf of Mexico shale with mineralogy very similar to the field of study was conducted by Rojas et al. (2006). This shale consisted of the kaolinite and illite clays with the water activity of approximately 0.82.

From the above discussions, we can constrain the assumptions for the input data in the chemical part of the numerical model we have used (see Table 5.1).

<table>
<thead>
<tr>
<th>Reflection coefficient</th>
<th>0.1</th>
<th>dimensionless</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation water activity</td>
<td>0.78-0.82</td>
<td>dimensionless</td>
</tr>
<tr>
<td>NaCl water activity</td>
<td>0.75-0.80</td>
<td>dimensionless</td>
</tr>
<tr>
<td>KCl water activity</td>
<td>0.92-0.96</td>
<td>dimensionless</td>
</tr>
</tbody>
</table>
5.3 Modeling of Temperature Alteration Effect

Since drilling is a dynamic process, circulation of the “cold” mud into the well results in the stress alteration due to the rock temperature change. Using the formulation described by Aadnoy and Looyeh (2011), the thermal stress induced, due to fluid-caused temperature alterations, can be calculated using Equation 5.9 (Zoback, 2010):

\[
\sigma_T = \frac{\alpha_m \times E \times (T - T_0)}{1 - \theta}, \quad (5.9)
\]

where \(\theta\) and \(E\) are the Poisson’s ratio and Young modulus, respectively. Both parameters are stress-dependent. \(\alpha_m\) is a volumetric thermal expansion coefficient of rock matrix (\(°K^{-1}\)). \(T\) is the circulation temperature (\(°K\)), and \(T_0\) is virgin rock temperature (\(°K\)).

By adding the stress alteration due to the thermal component, calculated from Equation 5.9, into Equation 5.8, we obtain the total stress alteration in Equation 5.10.

\[
\sigma_r = \Delta p_w, \\
\sigma_\theta = (\sigma_x + \sigma_y - \Delta p_w) - 2(\sigma_x - \sigma_y)\cos2\theta - 4\tau_{xy}\sin2\theta + \alpha \frac{1 - 2\theta}{1 - \theta} \Delta \Pi + \frac{\alpha_m \times E \times (T - T_0)}{1 - \theta}, \\
\sigma_z = \sigma_{zz} - 2\theta(\sigma_x - \sigma_y)\cos2\theta - 4\theta\tau_{xy}\sin2\theta + \alpha \frac{1 - 2\theta}{1 - \theta} \Delta \Pi + \frac{\alpha_m \times E \times (T - T_0)}{1 - \theta}, \\
\tau_{r\theta} = \tau_{rz} = 0, \\
\tau_{\theta z} = 2(\tau_{yz}\cos\theta - \tau_{xz}\sin\theta). \quad (5.10)
\]

\(T_0\) in Equation 5.9 was obtained using the temperature logs. A mathematical approach in determining the circulation temperature along the wellbore has been proposed by Edwardson et al. (1961). In this study, we have estimated this circulation temperature using a commercial software package provided by the cementing company. Since there were no cores available to conduct laboratory measurements to obtain the volumetric thermal expansion coefficients for different facies in the field of the study, these coefficients were utilized from the available literature (Wong and Brace, 1978). Wong and Brace (1978) performed experiments on several
formations, including limestone and quartz, under high confining pressures (200-300 MPa) to estimate the volumetric thermal expansion coefficients of these rocks. They found that the volumetric thermal expansion coefficient for the Oak Hall limestone was about 3.4±0.09*10⁻⁶ °C and 10.6±0.17*10⁻⁶ °C for quartz. These coefficients and 2.58*10⁻⁶ °C for the shale facies were utilized in this study to simulate the thermal stress alterations.

5.4 Modeling of the Flow Induced Stress Effects

Effects of flow-induced stresses have been captured in the modeling part of this study by utilizing Equation 5.11. This equation defines the stress alteration at the wellbore when a radial flow is introduced due to the overbalanced or underbalanced drilling.

\[
\sigma_r'' = (1 - \alpha) \frac{1 - 2\theta}{1 - \theta} \frac{P_w - P_p}{2} \left[ (1 - \left( \frac{a}{r} \right)^2 \left\{ 1 + \frac{1}{2 \log\left( \frac{b}{a} \right)} \right\} - \frac{\log\left( \frac{r}{a} \right)}{\log\left( \frac{b}{a} \right)} \right],
\]

\[
\sigma_{\theta}'' = (1 - \alpha) \frac{1 - 2\theta}{1 - \theta} \frac{P_w - P_p}{2} \left[ (1 - \left( \frac{a}{r} \right)^2 \left\{ 1 + \frac{1}{2 \log\left( \frac{b}{a} \right)} \right\} - 2 + \frac{\log\left( \frac{r}{a} \right)}{\log\left( \frac{b}{a} \right)} \right],
\]

\[
\sigma_z'' = (1 - \alpha) \frac{1 - 2\theta}{1 - \theta} (P_w - P_p) \left[ 1 - \frac{\log\left( \frac{r}{a} \right)}{\log\left( \frac{b}{a} \right)} \right],
\]

where, \(\sigma_r''\), \(\sigma_{\theta}''\) and \(\sigma_z''\) are the stress changes due to the effects of the induced flow; \(b\) is the outer radius.

At the wellbore when \(r=a\), the Equation 5.11 can be reduced to Equation 5.12.

\[
\sigma_r'' = 0,
\]

\[
\sigma_{\theta}'' = -(1 - \alpha) \frac{1 - 2\theta}{1 - \theta} (P_w - P_o), \quad \text{(5.12)}
\]

\[
\sigma_z'' = -(1 - \alpha) \frac{1 - 2\theta}{1 - \theta} (P_w - P_o),
\]

where \(P_w - P_o = \Delta p_w\).
By adding stress changes due to the effects of the induced flow, the final stress alteration numerical model is represented in Equation 5.13:

\[
\sigma_r = \Delta p_w, \\
\sigma_\theta = (\sigma_x + \sigma_y - \Delta p_w) - 2(\sigma_x - \sigma_y)\cos2\theta - 4\tau_{xy}\sin2\theta + \frac{1 - 2\theta}{1 - \theta} \Delta \Pi + \\
\frac{\alpha_m*E*(T-T_0)}{1-\theta} - (1 - \alpha)\frac{1-2\theta}{1-\theta}\Delta p_w, \\
\sigma_z = \sigma_{zz} - 2\theta(\sigma_x - \sigma_y)\cos2\theta - 4\theta\tau_{xy}\sin2\theta + \frac{1 - 2\theta}{1 - \theta} \Delta \Pi + \frac{\alpha_m*E*(T-T_0)}{1-\theta} - \\
(1 - \alpha)\frac{1-2\theta}{1-\theta}\Delta p_w, \\
\tau_{r\theta} = \tau_{rz} = 0, \\
\tau_{\theta z} = 2(\tau_{yz}\cos\theta - \tau_{xz}\sin\theta). 
\] (5.13)

5.5 Borehole Failure Criteria

One of the main factors influencing the wellbore-stability analyses is the selection of a formation failure criterion. An appropriate failure criterion should be applied for representing the true in-situ failure conditions. The feasibility of the selected criterion can be verified from the field observations. Two main categories of rock failure criterion exist. The first category takes into account the effect of the intermediate principle stress (3D failure criteria), i.e. the minimum as well as maximum principle stresses. The second category considers only the minimum and maximum principle stresses. The most ubiquitous criterion representing the first category is the Mohr-Coulomb rock failure criterion. Besides using this criterion, the Mogi-Coulomb rock failure criterion was utilized in this study to compare the two approaches. The outcomes from these two failure criteria were analyzed to select a criterion which would be appropriate for the West Kazakhstan Field.
5.5.1 Mohr-Coulomb Failure Criterion

As described by Al-Ajmi and Zimmerman (2006 (a)), the shear strength linearly increases with the effective mean stress ($\sigma_{m,2}$) in the Mohr-Coulomb failure criterion. This trend inhibits the creation of a failure plane. When the value of the maximum shear stress ($\tau_{max}$), developed on a specific plane, is enough to overcome the formation cohesion ($C$) and frictional force, the compressional failure occurs. Therefore, the Mohr-Coulomb compressional failure depends only on two principal stresses, the maximum ($\sigma_1$) and minimum ($\sigma_3$) principal stresses. The Mohr-Coulomb criterion can be described as:

$$\tau_{max} = c \cdot \cos\Phi + \sin\Phi \cdot \sigma_{m,2}.$$  \hspace{1cm} (5.14)

where $\Phi$ is the angle of internal friction.

The maximum shear stress in Equation 5.14 is expressed in Equation 5.15, and the effective mean stress is described in Equation 5.16.

$$\tau_{max} = \frac{\sigma_1 - \sigma_3}{2}.$$ \hspace{1cm} (5.15)

$$\sigma_{m,2} = \frac{\sigma_1 + \sigma_3}{2}.$$ \hspace{1cm} (5.16)

Then, considering pore pressure ($P_p$), the numerical solution for the Mohr-Coulomb failure criterion can be expressed as follows (Islam et al., 2010):

$$F = c \cdot \cos\Phi + \sin\Phi \cdot (\sigma_{m,2} - P_p) - \tau_{max}.$$  \hspace{1cm} (5.17)

Compressional failure occurs when $F$ is less than or equal to zero.

Even though the Mohr-Coulomb failure criterion is widely applied in geomechanical studies, several researchers emphasized that this criterion provides overpredicted results (Vernik and Zoback, 1992; Song and Haimson, 1997; Ewy, 1999; Al-Ajmi and Zimmerman, 2006 (a)).
Therefore, we have also applied the Mogi-Coulomb failure criterion to assure the predictions were representative of the real in-situ conditions.

### 5.5.2 Mogi-Coulomb Failure Criterion

The Mogi-Coulomb failure criterion was used to model the brittle rock failure in our study using the equations published by Al-Ajmi and Zimmerman (2006(a)). This criterion considers all three principle stresses and can be expressed as follows:

\[
\tau_{oct} = a + b \cdot \sigma_{m,2},
\]  

where \(\tau_{oct}\) is the octahedral shear stress; \(a\) and \(b\) are the Coulomb strength parameters. The octahedral shear stress and the Coulomb strength parameters are expressed in Equations 5.19, 5.20, and 5.21 (Al-Ajmi and Zimmerman (a), 2006).

\[
\tau_{oct} = \frac{1}{3} \sqrt{(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2}.
\]  

\[
a = \frac{2\sqrt{2}}{3} \cdot c \cdot \cos\phi.
\]  

\[
b = \frac{2\sqrt{2}}{3} \cdot \sin\phi.
\]

If \(\sigma_1 = \sigma_2\) or \(\sigma_2 = \sigma_3\) the Mogi-Coulomb failure criterion is reduced to the Mohr-Coulomb failure criteria. In the polyaxial stress domain, the Mogi-Coulomb failure criterion results would be very close to the results from the 3D Mohr-Coulomb failure criterion.

### 5.5.3 Tensile (Breakdown) Failure Criterion

When the least compressive principle stress at the wellbore \((\sigma_{t \, min}\) in Equation 5.5) exceeds the tensile strength of rock, the formation will fail in tensile mode. The criterion can be expressed as follows (Yu et al., 2001):

\[\]
\[ F = \sigma_{t \min} + T_s, \tag{5.22} \]

where \( \sigma_{t \min} \) is the effective minimum compressional principle stress at the wellbore; \( T_s \) is the tensile strength of formation. Tensile failure occurs when \( F \leq 0 \).

### 5.6 Risk Analysis

Since some uncertainties were exposed in the wellbore-stability input data determination, the sensitivity analysis of the collapse and tensile failure pressure for a given set of input parameters was performed.

#### 5.6.1 Analytical Solution

An analytical Mogi-Coulomb solution for collapse and fracture pressures in vertical wells was utilized for the wellbore stability analysis discussed in this chapter (Al-Ajmi and Zimmerman, 2006(b)).

There are three cases which can occur at a vertical wellbore. These are

1. \( \sigma_z \geq \sigma_\theta \geq \sigma_r \),
2. \( \sigma_\theta \geq \sigma_z \geq \sigma_r \),
3. \( \sigma_\theta \geq \sigma_r \geq \sigma_z \).

Let’s name these cases as Case 1, Case 2, and Case 3. Equations 5.24, 5.25, and 5.26 correspond to these cases respectively. Note that Equations 5.24, 5.25, and 5.26 describe wellbore breakout failure occurrence:

\[
P_{wb1} = \frac{1}{6-2b'^2/2} \left[ (3 * A + 2 * b' * K) - \sqrt{H + 12 * (K^2 + b' * A * K)} \right], \tag{5.24} \]

\[
P_{wb2} = \frac{1}{2} * A - \frac{1}{6} * \sqrt{12 \left[ a' + b' * (A - 2 * p) \right]^2 - 3 * (A - 2 * B)^2}, \tag{5.25} \]

\[
P_{wb3} = \frac{1}{6-2b'^2/2} \left[ (3 * A - 2 * b' * G) - \sqrt{H + 12 * (G^2 - b' * A * G)} \right], \tag{5.26} \]

where

\[ A = 3 * S_{H_{max}} - S_{h_{min}}, \tag{5.27} \]
In Equations 5.32 and 5.33 \(c\) and \(\Phi\) are the rock cohesion and internal friction angle, respectively. An analytical solution for fracture pressure in a vertical wellbore for these three cases is shown in Equations 4.34, 4.35, and 4.36, respectively.

\[
P_{wf1} = \frac{1}{6 - 2b'^2} \left[ (3 \times D + 2 \times b' \times N) + \sqrt{J + 12 \times (N^2 + b' \times D \times N)} \right],
\]

\[
P_{wf2} = \frac{1}{2} \times D + \frac{1}{6} \times \sqrt{12 \times [a' + b' \times (D - 2 \times P_p)]^2 - 3 \times (A - 2 \times B)^2},
\]

\[
P_{wf3} = \frac{1}{6 - 2b'^2} \times \left[ (3 \times A - 2 \times b' \times G) - \sqrt{H + 12 \times (G^2 - b' \times A \times G)} \right],
\]

where

\[
D = 3 \times Sh_{min} - SH_{max},
\]

\[
E = S_{ov} - 2 \times \theta \times (SH_{max} - Sh_{min}),
\]

\[
J = D^2 \times (4 \times b'^2 - 3) + (E^2 - D \times E) \times (4 \times b'^2 - 12),
\]

\[
N = a' + b' \times (E - 2 \times P_p),
\]

\[
M = N + b' \times D.
\]

Note that all pressure units in Equations 5.24 - 5.41 are in MPa.
It is important to emphasize that physico-chemical interactions, temperature and flow-induced stresses have been added to Equations 5.27, 5.28, 5.37, and 5.38 to consider the contributions of all three factors in calculations of the principle stresses at the wellbore.

5.6.2 Sensitivity Analysis

In this study, a program entitled “@Risk” was utilized for wellbore-stability sensitivity analysis. Ranges of the input data for different parameters are given in Table 5.2.

The ranges of the input data for different parameters are determined using the results of the variations in the input data acquisition analysis as discussed in detail in Chapter 4 and listed in Table 5.3, Figure 5.2, and Figure 5.3. The analytical approach discussed above has been utilized to obtain the output data. We have not observed any drilling-induced tensile fractures or breakouts in our analysis at the depth of the input data. The absence of these wellbore features was validated with the analytical approach. As is evident in Table 5.3, there is a relatively wide mud window between 45.6 MPa (collapse pressure) and 89.6 MPa (fracture pressure).

The drilling mud pressure in this case was 48.28 MPa, which was sufficient to counteract the wellbore-collapse tendency. The next step was to analyze P10 and P90 values for the collapse and fracture pressures as illustrated in Figures 5.2 and 5.3. The probability density of the pressure to prevent wellbore collapse is illustrated in Figure 5.2. The P10 value in this case is calculated to be 43.13 MPa, and the P90 value is 49.55 MPa. To prevent a breakout occurrence, there is a 10% probability that the required wellbore pressure needed will be less than 43.13 MPa, and a 90% probability that the required wellbore pressure will be less than 49.55 MPa. Using the same concept, the probability density of the critical pressure, beyond which the wellbore fracture would occur, is illustrated in Figure 5.3. The P10 value in this case is 85.4 MPa, and the P90 value is 125.8 MPa. There is a 10% probability for the required wellbore pressure will be less than 85.4 MPa to fracture the well at this depth, and a 10% probability that the critical fracture pressure will be greater than 125.8 MPa.

Even though the probability density charts show the level of confidence for particular values with the given input data set, it is interesting to analyze the sensitivity of the output data.
to the input parameters used. To investigate this sensitivity, the Tornado charts for the mud-window pressures have been utilized (see Figures 5.4 and 5.5).

Table 5.2  Ranges of the Input Data for the Wellbore-Stability Sensitivity Analysis

<table>
<thead>
<tr>
<th>PARAMETERS</th>
<th>MIN</th>
<th>MOST LIKELY</th>
<th>MAX</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pore Pressure, MPa</td>
<td>37.93</td>
<td>43.80</td>
<td>48.28</td>
</tr>
<tr>
<td>Drilling ECD, MPa</td>
<td>51.66</td>
<td>52.00</td>
<td>52.76</td>
</tr>
<tr>
<td>Swab pressure, MPa</td>
<td>48.28</td>
<td>48.54</td>
<td>49.93</td>
</tr>
<tr>
<td>Static Poisson's ratio</td>
<td>0.3</td>
<td>0.35</td>
<td>0.4</td>
</tr>
<tr>
<td>Static Young's modulus, GPa</td>
<td>55.2</td>
<td>62.4</td>
<td>75.8</td>
</tr>
<tr>
<td>UCS, MPa</td>
<td>35.7</td>
<td>45.0</td>
<td>55.2</td>
</tr>
<tr>
<td>Tensile strength, MPa</td>
<td>2.1</td>
<td>2.2</td>
<td>5.5</td>
</tr>
<tr>
<td>Friction angle, deg</td>
<td>25</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td>Cohesion, MPa</td>
<td></td>
<td>calculated from the UCS and friction angle</td>
<td></td>
</tr>
<tr>
<td>OBS, MPa</td>
<td>100.0</td>
<td>100.5</td>
<td>101.4</td>
</tr>
<tr>
<td>Shmin, MPa</td>
<td>57.9</td>
<td>76.11</td>
<td>83</td>
</tr>
<tr>
<td>SHmax, MPa</td>
<td>74.0</td>
<td>80</td>
<td>86.2</td>
</tr>
<tr>
<td>Biot's coefficient</td>
<td>0.6</td>
<td>0.8</td>
<td>1</td>
</tr>
<tr>
<td>Aw_fl</td>
<td>0.65</td>
<td>0.9</td>
<td>0.95</td>
</tr>
<tr>
<td>Aw_sh</td>
<td>0.9</td>
<td>0.95</td>
<td>0.98</td>
</tr>
<tr>
<td>Membrane efficiency</td>
<td>0.001</td>
<td></td>
<td>0.1</td>
</tr>
<tr>
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<td>0.000001</td>
<td>0.0000012</td>
</tr>
<tr>
<td>T, °C</td>
<td>60</td>
<td>65</td>
<td>75</td>
</tr>
<tr>
<td>T_o, °C</td>
<td>83</td>
<td>85</td>
<td>87</td>
</tr>
</tbody>
</table>

It is evident from Figure 5.4 that the most influential parameters in calculating the required minimum wellbore pressure to prevent breakouts are pore pressure, friction angle, UCS, static Poisson’s ratio, and principle horizontal stress magnitudes. It is important to emphasize the role of the overburden in these calculations. Yet, the scatter of possible values for the overburden stress has been significantly narrowed in this case as shown in Figure 5.4, indicating the low sensitivity of this parameter. The value of the maximum horizontal stress is also equally critical. However, the probability values for the maximum horizontal stress have been obtained using the stress polygon approach. Hence the correlation coefficients for the input data are also low in the Tornado charts.
Table 5.3 Outputs of Wellbore-Stability Sensitivity Analysis

<table>
<thead>
<tr>
<th>OUTPUTS</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical stress, MPa</td>
<td>0.3</td>
</tr>
<tr>
<td>Temperature stress, MPa</td>
<td>-1.4</td>
</tr>
<tr>
<td>Flow induced stress, MPa</td>
<td>2.3</td>
</tr>
<tr>
<td>$\sigma_r$, MPa</td>
<td>48.9</td>
</tr>
<tr>
<td>$\sigma_\theta$, MPa</td>
<td>115.1</td>
</tr>
<tr>
<td>$\sigma_z$, MPa</td>
<td>103.5</td>
</tr>
<tr>
<td>A</td>
<td>165.2</td>
</tr>
<tr>
<td>B</td>
<td>104.8</td>
</tr>
<tr>
<td>H</td>
<td>36062.2</td>
</tr>
<tr>
<td>K</td>
<td>26.1</td>
</tr>
<tr>
<td>G</td>
<td>142.9</td>
</tr>
<tr>
<td>a'</td>
<td>13.3</td>
</tr>
<tr>
<td>b'</td>
<td>0.71</td>
</tr>
<tr>
<td>D</td>
<td>148.31</td>
</tr>
<tr>
<td>E</td>
<td>97.75</td>
</tr>
<tr>
<td>J</td>
<td>27428.7</td>
</tr>
<tr>
<td>N</td>
<td>21.1</td>
</tr>
<tr>
<td>M</td>
<td>126</td>
</tr>
<tr>
<td>$P_{wb\ 2}$, MPa</td>
<td>45</td>
</tr>
<tr>
<td>$P_{wf\ 2}$, MPa</td>
<td>104</td>
</tr>
</tbody>
</table>

The critical fracture pressure results differ as shown in Figure 5.5. In this Tornado chart, the highest contributors are the static Poisson’s ratio, Biot’s coefficient, tensile strength, and the maximum horizontal stress magnitude. Note that, most of the parameters that impact the chemical, thermal, and flow-induced stresses are not significant as shown in both Tornado charts. Yet, if the effects of these parameters on the reduction or increase of the key rock properties are considered, the Tornado chart might have a higher influence on these parameters currently appearing to have minor impacts. Based on this sensitivity analysis, it is critical to emphasize that special consideration should be given to the acquisition of reliable geomechanical rock property data and in-situ principle stress magnitudes.
Figure 5.2  Probability density of the pressure to prevent the wellbore collapse. The P10 value in this case is 43.13 MPa, and the P90 value is 49.55 MPa. There is a 10% probability that the required wellbore pressure is below 43.13 MPa, and a 10% probability that the required wellbore pressure is greater than 49.55 MPa.

Figure 5.3  Probability density of the critical fracture pressure. The P10 value in this case is 70.1 MPa, and the P90 value is 109 MPa. There is a 10% probability that the required wellbore pressure to fracture the well at this depth is below 70.1 MPa, and a 10% probability that the critical fracture pressure will be greater than 109 MPa.
Figure 5.4  Correlation of the various input parameters used in the wellbore stability analysis for determining the fluid pressure to prevent breakout occurrences.

Figure 5.5  Correlation of the various input parameters to determine the critical wellbore-fracture pressure.
5.7 Modeling of Formation Anisotropy Effect

In shale reservoirs and shales overlying and underlying the reservoirs as seal formations, two types of anisotropy have been observed: intrinsic anisotropy and induced anisotropy (Tutuncu, 2010). These anisotropies impact significantly on the geomechanical properties of the formations being investigated. Intrinsic anisotropy depends on a lamination level of rock and pore-space orientations between the layers. Induced anisotropy is mostly impacted by differences in the stress magnitudes. The stress and formation anisotropy in the West Kazakhstan Field was analyzed using dipole sonic (DSI) and image-log data. The isotropic and anisotropic Young’s moduli and Poisson’s ratios were compared as illustrated in Figure 5.6. Then, using these isotropic and anisotropic parameters, the isotropic and anisotropic minimum horizontal stress magnitudes were calculated in the interval 2721-5041 m. An equation used in this study to calculate the anisotropic minimum horizontal stress magnitude is presented in Equation 5.42 (Kadyrov and Tutuncu, 2012):

\[ S_{h_{\text{min, anis, VT}}} = \frac{\theta_{\text{vert}}}{1-\theta_{\text{horiz}}} \cdot \frac{E_{\text{horiz}}}{E_{\text{vert}}} \cdot \left( S_{ov} - \alpha \cdot P_p \right) + \alpha \cdot P_p + T_s, \]  

(5.42)

where the Biot’s coefficient \( \alpha \) was assumed to be 0.8 in the absence of core measurements. Note that calculated anisotropic minimum horizontal stress represents the vertical transverse isotropic formation condition. The results of calculations in the interval 4835-4855 are illustrated in Figure 5.6. Note that in the low shale intervals, the anisotropy is less significant compared to the shaly intervals. In such cases, the anisotropy may be related to clay lamination, shale weak beddings, and DSI measurement errors due to washouts in shaly intervals.

In this study the absolute difference between the isotropic and anisotropic minimum horizontal stress values was considered to be the level of anisotropy in the formations of interest. The level of anisotropy was estimated in EMW units (g/cm³) for the entire interval of interest and is illustrated in Figure 5.7. Since the lithology in the interval of interest is dominated by carbonates, a low anisotropy level in the given interval is observed as shown in Figure 5.7. Due to the relatively low level of anisotropy, limited DSI data, and possible DSI data errors in shaly
wahout intervals, the $S_{h_{\text{min}}}$ did not vary significantly and an isotropic $S_{h_{\text{min}}}$ magnitude approach was utilized throughout the study.

Figure 5.6  The isotropic and anisotropic Young’s moduli and Poisson’s ratio with the calculated isotropic and anisotropic values of the minimum horizontal stress for the vertical transverse isotropic condition. The red rectangle in the figure represents the shaly interval with significant formation anisotropy. The intervals with the low shale content do not show large anisotropy. Track 1 is a measured depth in m; Track 2 is clay volume in fraction; Track 3 is the isotropic and anisotropic dynamic Young’s moduli in Mpsi; Track 4 is the isotropic and anisotropic static Young’s moduli in Mpsi; Track 5 is the dynamic isotropic and anisotropic Poisson’s ratios; Track 6 is the static isotropic and anisotropic Poisson’s ratios; Track 7 shows the isotropic and anisotropic minimum horizontal stresses in psi.
Figure 5.7 Histogram for the level of formation anisotropy based on the absolute difference between the isotropic and anisotropic minimum horizontal stress magnitudes in the vertical transverse isotropic condition.

5.8 Numerical Modeling Results and Discussion

The Mohr-Coulomb and Mogi-Coulomb failure criteria have been utilized in the numerical model to evaluate the critical mud weights to prevent breakouts and tensile fractures in vertical and arbitrarily oriented wellbores. The numerical model was applied to the problematic interval of vertical Well A that was drilled using a mud weight of 1.17 g/cm³. Different depths (cases) were selected within the interval of interest. Cases 1 and 2 represent TVD at which wellbore breakouts occurred, and Case 3 corresponds to the depth where no breakouts were observed. Input data for the numerical model with Cases 1, 2 and 3 are shown in Tables 5.4, 5.5, and 5.6, respectively.
In these three cases the in-situ principle stresses, lithology, and rock properties change. With an increase in shale volume, the UCS and internal friction angle reduce. The outcomes of numerical modeling for Cases 1, 2, and 3 are illustrated in Figures 5.8, 5.9, and 5.10, respectively. These figures show a required mud weight to prevent wellbore breakouts using the Mogi-Coulomb and Mohr-Coulomb failure criteria. The figures also show the maximum mud weight, before wellbore fracturing occurs, for an arbitrarily orientated wellbore for Cases 1, 2, and 3.

In all three cases, the required mud weight to avoid wellbore breakouts using the Mohr-Coulomb failure criterion is higher (by approximately 0.1 g/cm$^3$) than the calculated mud weight obtained from the Mogi-Coulomb failure criterion. A possible reason for this difference is the strengthening effect of an intermediate principle stress at the wellbore, as in the case of the Mogi-Coulomb criterion.

To validate the feasibility of the Mogi-Coulomb and Mohr-Coulomb criteria for the study field, both criteria were applied for horizontal Well H that was drilled with considerable wellbore-stability issues in the Devonian interval with the mud weight of 1.17 g/cm$^3$. Note that Well H was drilled close to Well A. As a mitigation plan for wellbore-stability issues at Well H, the mud weight was gradually increased from 1.17 g/cm$^3$ to 1.27 g/cm$^3$ during sidetracking with the wellbore inclination of 42 degrees at the problematic shaly interval. As a result, the well was drilled up to the planned total depth with minor wellbore-stability issues. It should be noted that some breakouts at the problematic intervals were present after drilling with the mud weight of 1.27 g/cm$^3$. However, these breakouts did not cause wellbore-stability issues, probably due to a narrow breakout width. The analysis of mud weight used to drill Well H at the particular inclination and azimuth showed that the proposed numerical model with the Mogi-Coulomb failure criterion is feasible for this study. Therefore, it is recommended to use the numerical model with the imbedded Mogi-Coulomb criterion in order to avoid severe wellbore-breakout incidents and circumvent an overestimation of the required mud weight.

Even with a small probability of wellbore fracturing at the interval of interest, the results, shown in Figures 5.8, 5.9, and 5.10, are considered to be accurate with the calculated tensile strength. For the Devonian age intervals, it is recommended to drill deviated wells in the direction +/- 30 degrees from the direction of the maximum horizontal stress to prevent wellbore
breakouts or significantly reduce a breakout width. The formation breakdown risk in the given interval is low even with the variation of the wellbore azimuth. Also, based on the results of the numerical modeling, the wellbore inclination at the interval of interest should be above 60 degrees to avoid the use of high mud weights.

Table 5.4  Input Data Used for Case 1

<p>| | |</p>
<table>
<thead>
<tr>
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</tr>
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<tbody>
<tr>
<td>TVD, m</td>
<td>4845.2</td>
</tr>
<tr>
<td>Lithology</td>
<td>50% Limestone and 50% Shale</td>
</tr>
<tr>
<td>Rock tensile strength, MPa</td>
<td>6</td>
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<tr>
<td>Uniaxial compressive strength, MPa</td>
<td>56.8</td>
</tr>
<tr>
<td>Young’s modulus, GPa</td>
<td>15.77</td>
</tr>
<tr>
<td>Poisson’s ratio, unitless</td>
<td>0.45</td>
</tr>
<tr>
<td>Biot’s coefficient, unitless</td>
<td>0.8</td>
</tr>
<tr>
<td>Internal friction angle, deg</td>
<td>33.2</td>
</tr>
<tr>
<td>Overburden stress, MPa</td>
<td>113.7</td>
</tr>
<tr>
<td>Minimum horizontal stress, MPa</td>
<td>97</td>
</tr>
<tr>
<td>Maximum horizontal stress, MPa</td>
<td>133</td>
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<tr>
<td>Azimuth of max. horizontal stress, deg</td>
<td>155</td>
</tr>
<tr>
<td>Pore pressure, MPa</td>
<td>55.8</td>
</tr>
<tr>
<td>Thermal expansion coefficient, $C^{-1}$</td>
<td>$2.8*10^{-6}$</td>
</tr>
<tr>
<td>Formation temperature change, °C</td>
<td>-20</td>
</tr>
<tr>
<td>Membrane efficiency, unitless</td>
<td>0.1</td>
</tr>
<tr>
<td>Chemical activity of shale pore water</td>
<td>0.8</td>
</tr>
<tr>
<td>Chemical activity of drilling fluids</td>
<td>0.7</td>
</tr>
<tr>
<td>Formation temperature, °C</td>
<td>95</td>
</tr>
<tr>
<td>Input Data Used for Case 2</td>
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</tr>
<tr>
<td>--------------------------</td>
<td>--</td>
</tr>
<tr>
<td><strong>TVD, m</strong></td>
<td>4881.3</td>
</tr>
<tr>
<td><strong>Lithology</strong></td>
<td>66% Limestone and 32% Shale</td>
</tr>
<tr>
<td><strong>Rock tensile strength, MPa</strong></td>
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<td><strong>Uniaxial compressive strength, MPa</strong></td>
<td>61.7</td>
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<tr>
<td><strong>Young’s modulus, GPa</strong></td>
<td>18.35</td>
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<td><strong>Poisson’s ratio, unitless</strong></td>
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<td><strong>Biot’s coefficient, unitless</strong></td>
<td>0.8</td>
</tr>
<tr>
<td><strong>Internal friction angle, deg</strong></td>
<td>37.1</td>
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<tr>
<td><strong>Overburden stress, MPa</strong></td>
<td>114.5</td>
</tr>
<tr>
<td><strong>Minimum horizontal stress, MPa</strong></td>
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<td><strong>Azimuth of max. horizontal stress, deg</strong></td>
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<td><strong>Pore pressure, MPa</strong></td>
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<tr>
<td><strong>Thermal expansion coefficient, C^{-1}</strong></td>
<td>2.5*10^{-6}</td>
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<tr>
<td><strong>Formation temperature change, °C</strong></td>
<td>-20</td>
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<td><strong>Membrane efficiency, unitless</strong></td>
<td>0.1</td>
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<td><strong>Chemical activity of shale pore water</strong></td>
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<td>0.7</td>
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Table 5.6  Input Data Used for Case 3.

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<td>Lithology</td>
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<td>Rock tensile strength, MPa</td>
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</tr>
<tr>
<td>Uniaxial compressive strength, MPa</td>
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<tr>
<td>Young’s modulus, GPa</td>
<td>66.8</td>
</tr>
<tr>
<td>Poisson’s ratio, unitless</td>
<td>0.34</td>
</tr>
<tr>
<td>Biot’s coefficient, unitless</td>
<td>0.8</td>
</tr>
<tr>
<td>Internal friction angle, deg</td>
<td>45</td>
</tr>
<tr>
<td>Overburden stress, MPa</td>
<td>114.9</td>
</tr>
<tr>
<td>Minimum horizontal stress, MPa</td>
<td>94.5</td>
</tr>
<tr>
<td>Maximum horizontal stress, MPa</td>
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</tr>
<tr>
<td>Azimuth of max. horizontal stress, deg</td>
<td>155</td>
</tr>
<tr>
<td>Pore pressure, MPa</td>
<td>52.4</td>
</tr>
<tr>
<td>Thermal expansion coefficient, °C⁻¹</td>
<td>3.3*10⁻⁶</td>
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<tr>
<td>Membrane efficiency, unitless</td>
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</tr>
<tr>
<td>Chemical activity of shale pore water</td>
<td>0.8</td>
</tr>
<tr>
<td>Chemical activity of drilling fluids</td>
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<tr>
<td>Formation temperature, °C</td>
<td>95</td>
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</table>
Figure 5.8  I) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 1 utilizing Mogi-Coulomb failure criterion. II) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 1 utilizing Mohr-Coulomb failure criterion.
Figure 5.8 (cont’d) III) Maximum mud weight before wellbore fracturing occurs for an arbitrarily oriented well for Case 1. Color bar is mud weight in g/cm$^3$. The scale ranges of color bars are not the same.
Figure 5.9  I) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 2 utilizing Mogi-Coulomb failure criterion. II) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 2 utilizing Mohr-Coulomb failure criterion.
Figure 5.9 (cont’d)  III) Maximum mud weight before wellbore fracturing occurs for an arbitrarily oriented well for Case 2. Color bar is mud weight in g/cm$^3$. The scale ranges of color bars are not the same.
Figure 5.10  I) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 3 utilizing Mogi-Coulomb failure criterion. II) Required mud weight to prevent wellbore breakout for an arbitrarily oriented well for Case 3 utilizing Mohr-Coulomb failure criterion.
Figure 5.10 (cont’d) III) Maximum mud weight before wellbore fracturing occurs for an arbitrarily oriented well for Case 3. Color bar is mud weight in g/cm$^3$. The scale ranges of color bars are not the same.
6.1 Study Conclusions

An integrated wellbore-stability analysis study was implemented to effectively plan the future drilling operations in the West Kazakhstan Field, to maximize the drilling margin for the future wells drilled, and to optimize the future field development.

The conclusions of this study are as follows:

1. A special wellbore-stability problem-diagnostic scheme was first used to identify problematic horizons. The possible causes of wellbore stability issues were narrowed down. It was found that the well trajectory, drilling fluid density, and types of water-based mud have a dominant impact on the occurrence of the wellbore-stability problems.

2. The enhanced geological model has been helpful for better visualizing the problematic horizons and populating of the obtained wellbore-stability input parameters throughout the field.

3. Even without geomechanical core measurements, it is feasible to obtain reliable required input data utilizing available well log, drilling, geological data, as well as the tectonic history of the interest area to solve wellbore-stability issues. It should be emphasized that availability of the key wells with critical well-log data is of utmost importance to conduct wellbore-stability studies without available core measurement data.

4. It is possible to capture several effects of the stress variations at the wellbore with the new numerical model. These effects are the mechanical stress, temperature alteration, shale-fluid physicochemical interaction, and the flow-induced stress using the Mohr-Coulomb and Mogi-Coulomb failure criteria. However, comprehensive laboratory measurements should be conducted to consider an alteration of formation geomechanical properties due to the introduction of drilling filtrate, temperature change, and pore pressure fluctuation under the in-situ stress conditions.
5. Based on the results of the conducted risk analysis, the uncertainty of the following critical input parameters should be addressed in the drilling margin calculations:
   - the in-situ principle horizontal stresses
   - uniaxial compressive strength,
   - Biot’s coefficient
   - the internal friction angle of formation
   - pore pressure

6. It is feasible to predict pore pressure along the interval of interest utilizing the Eaton method with significant modifications of the Eaton’s coefficients.

7. A comparison of the numerical modeling results with the field observations implies that obtained wellbore-stability input data is in an acceptable range even with some data uncertainty.

8. The Mogi-Coulomb formation failure criterion was found to be a better characterization of the brittle rock failure in the West Kazakhstan Field. The utilization of the Mohr-Coulomb failure criterion resulted in overestimation of the wellbore collapse pressure, probably due to ignoring the strengthening effect of the intermediate principle stress.

9. The stress regime in the West Kazakhstan Field was found to be strike-slip, which is in agreement with the tectonic history of the Pre-Caspian Basin and the existing faults in the West Kazakhstan Field.

10. Based on the results of this study, the mitigation and/or prevention of wellbore-stability issues in the West Kazakhstan Field are feasible tasks.

11. The outcomes of this study can be utilized for further field developments for enhancement of the hydrocarbon production (e.g. hydraulic fracturing, open-hole completions, and enhanced hydrocarbon recovery).

12. The wellbore-stability model developed in this study for the West Kazakhstan Field can be potentially applied to other fields in the Pre-Caspian Basin using a similar approach which might be adjusted to the particular field specifications and requirements.

13. Outcomes of this study would be helpful in reducing the cost and non-productive time during drilling operations.
6.2 Future Work

In Chapter 4 we discussed the lack of core measurements in this study. Even though we are confident with the obtained input data for this wellbore-stability analysis, laboratory core measurements to obtain geomechanical formation properties for different facies in the West Kazakhstan Field would help increase the confidence level of the obtained study results.

The recommendations for future work from this study are as follows:

1. The geomechanical formation properties should be obtained under the true-triaxial core measurements for various facies of the West Kazakhstan Field.
2. The obtained laboratory geomechanical parameters should be correlated to the petrophysical parameters to derive these geomechanical parameters from well logs and to reduce costly geomechanical laboratory measurements in the life cycle of the field.
3. Extended leak-off tests should be conducted at various intervals to calibrate the calculated magnitude of the minimum horizontal stress.
4. Annular pressure gauges should be included in the drilling BHA to facilitate the evaluation of the circulation, surge, and pressures.
5. The Holbrook method should be calibrated for the West Kazakhstan Field conditions.
NOMENCLATURE

Symbols

\( \alpha \)  
Biot’s coefficient, unitless

\( \alpha_m \)  
Volumetric thermal expansion coefficient of rock matrix, \( \circ K^{-1} \)

\( \beta \)  
Compaction strain-hardening coefficient, unitless

\( \gamma \)  
Wellbore inclination from the vertical, degrees

\( \Delta \Pi \)  
Osmotic pressure, MPa (psi)

\( \Delta P \)  
Difference between wellbore pressure and pore pressure, MPa (psi)

\( \Delta t_{co} \)  
Compressional-wave slowness, \( \mu sec/ft \) (\( \mu sec/m \))

\( \Delta t_s \)  
Shear-wave slowness, \( \mu sec/ft \) (\( \mu sec/m \))

\( \Theta_{300} \)  
Dial reading on Fann viscometer at rotor speed 300 rpm, cP

\( \Theta_{600} \)  
Dial reading on Fann viscometer at rotor speed 600 rpm, cP

\( \mu_i \)  
Friction coefficient, unitless

\( \rho \)  
Bulk density, g/cm\(^3\) (kg/m\(^3\))

\( \sigma_1 \)  
Maximum principle stress, MPa (psi)

\( \sigma_2 \)  
Intermediate principle stress, MPa (psi)

\( \sigma_3 \)  
Minimum principle stress, MPa (psi)

\( \sigma_{eff} \)  
Effective stress, MPa (psi)

\( \sigma_{m,2} \)  
Effective mean stress, MPa (psi)
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\sigma_{max}$</td>
<td>Effective stress required to reduce the mineral porosity to zero, MPa (psig)</td>
</tr>
<tr>
<td>$\sigma_\theta$</td>
<td>Hoop stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_\theta'$</td>
<td>Hoop stress alteration due to the introduction of osmotic pressure, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_\theta''$</td>
<td>Hoop stress alteration due to the flow-induced stress effect, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_r$</td>
<td>Radial stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_{rr}$</td>
<td>Radial effective principle stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_r'$</td>
<td>Radial stress alteration due to the introduction of osmotic pressure, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_r''$</td>
<td>Radial stress alteration due to the flow-induced stress effect, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_T$</td>
<td>Thermal stress, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_{t max}$</td>
<td>Maximum effective principle stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_{t min}$</td>
<td>Minimum effective principle stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_x$</td>
<td>Stress in x-axis in Cartesian coordinate system, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_y$</td>
<td>Stress in y-axis in Cartesian coordinate system, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_z$</td>
<td>Axial stress at the wellbore, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_z'$</td>
<td>Axial stress alteration due to the introduction of osmotic pressure, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_z''$</td>
<td>Axial stress alteration due to the flow-induced stress effect, MPa (psi)</td>
</tr>
<tr>
<td>$\sigma_{zz}$</td>
<td>Stress in z-axis in Cartesian coordinate system, MPa (psi)</td>
</tr>
<tr>
<td>$\tau_{max}$</td>
<td>Maximum shear stress, MPa (psi)</td>
</tr>
<tr>
<td>$\tau_{oct}$</td>
<td>Octahedral shear stress, MPa (psi)</td>
</tr>
<tr>
<td>$\tau_{xy}$</td>
<td>Shear stress in x-y plane, MPa (psi)</td>
</tr>
<tr>
<td>$\tau_{xz}$</td>
<td>Shear stress in x-z plane, MPa (psi)</td>
</tr>
</tbody>
</table>
\( \tau_{yz} \)  Shear stress in \( y-z \) plane, MPa (psi)

\( \tau_{r\theta} \)  Shear stress in \( r-\theta \) plane, MPa (psi)

\( \tau_{r\phi} \)  Shear stress in \( r-\phi \) plane, MPa (psi)

\( \tau_{\theta z} \)  Shear stress in \( \theta-z \) plane, MPa (psi)

\( \vartheta \)  Poisson’s ratio, unitless

\( \vartheta_{fast} \)  Poisson’s ratio calculated using fast shear-wave slowness, unitless

\( \vartheta_{slow} \)  Poisson’s ratio calculated using slow shear-wave slowness, unitless

\( \Phi \)  Internal friction angle, degrees

\( \varphi \)  Wellbore azimuth from the direction of \( SH_{max} \), degrees

\( \Phi \)  Formation porosity, fraction

\( a \)  Coefficient, unitless

\( a \)  Radius of the wellbore, inches

\( a \)  Coulomb strength parameter, MPa (psi)

\( a_{w,df} \)  Chemical activity of the fresh water, unitless

\( a_{w,sh} \)  Chemical activity of shale or formation pore water, unitless

\( b \)  Coefficient, unitless

\( b \)  Coulomb strength parameter, MPa (psi)

\( C \)  Formation cohesion, MPa (psi)

\( c \)  Coefficient, unitless

\( E \)  Young’s modulus, GPa (Mpsi)

\( E_d \)  Dynamic Young’s modulus, GPa (Mpsi)
$E_{dc}$ Corrected dynamic modulus, MPa (psig)

$E_{fast}$ Young’s modulus calculated using fast shear-wave slowness, GPa, (Mpsi)

$E_s$ Static Young’s modulus, GPa, (Mpsi)

$E_{slow}$ Young’s modulus calculated using slow shear-wave slowness, GPa, (Mpsi)

$r$ Outer radius, inches

GR Gamma ray, gAPI

$G_s$ Shear modulus, GPa (Mpsi)

$l_m$ Reflection coefficient, unitless

$K$ Bulk modulus, GPa, (Mpsi)

$K_d$ Dynamic bulk modulus, GPa (Mpsi)

$M$ Compressional modulus, GPa (Mpsi)

$P$ External stress, MPa (psi)

$P_p$ Pore pressure, MPa (psi)

$P_{wb1}$ Critical wellbore breakout pressure, MPa (psi)

$P_{wf1}$ Critical wellbore breakdown pressure, MPa (psi)

$R$ The universal gas constant, $\frac{J}{K*mole}$

$SH_{max}$ Maximum horizontal stress, MPa (psi)

$S_{h_{min, anis, VTI}}$ Anisotropic minimum horizontal stress, MPa (psi)

$S_{h_{min}}$ Minimum horizontal stress, MPa (psi)

$S_{ov}$ Overburden stress, MPa (psi)

$T$ Circulation temperature, °K
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_o$</td>
<td>Absolute temperature, °K</td>
</tr>
<tr>
<td>$T_s$</td>
<td>Tensile strength, MPa (psi)</td>
</tr>
<tr>
<td>UCS</td>
<td>Uniaxial compressive strength, MPa (psi)</td>
</tr>
<tr>
<td>$V_p$</td>
<td>Compressional-wave velocity, m/sec (ft/sec)</td>
</tr>
<tr>
<td>$V_s$</td>
<td>Shear-wave velocity, m/sec (ft/sec)</td>
</tr>
<tr>
<td>$V_w$</td>
<td>The molar volume of the water, m$^3$</td>
</tr>
<tr>
<td>$w_b$</td>
<td>Width of breakouts, degrees</td>
</tr>
</tbody>
</table>
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APPENDIX A

PER-FLEX POLYMER

The Per-flex polymer system was successfully used by the mud service company in a few fields in the Pre-Caspian Basin. Even though the mud service company observed a good performance of this mud system in these fields, the Per-flex polymer did not perform well in the West-Kazakhstan Field compared to KCl/Polymer systems. This implies there is some room in studying and improving the filtrate-shale fluid compatibility in order to utilize the Per-flex polymer system in more efficient way in the West Kazakhstan field. The information below about the Per-flex polymer system is provided by the mud service company.

As the interval contains halite and as it has potential to create hole instability caused by the presence of reactive clays and interlaid mudstones, a Salt Saturated PER-FLEX fluid system is recommended to apply in this section instead of other widely known inhibitive systems based on the use of traditional shale inhibitors such as KCl or Glycols.

A key component of the proposed PER-FLEX system is MAX-PLEX, an aluminum-resin complex designed to precipitate in shale pore throats and on the surface of shale platelets to prevent the invasion of mud filtrate and pressure transmission, providing borehole stability across the near wellbore area. MAX-PLEX imparts stability of reactive formations, stabilizes shale and minimizes bit/BHA balling.

MAX-PLEX properties:

- Precipitated out inside pore throat due to drop of pH in situ and react with cations in connate water chemistry of clay resulting in reducing shale permeability.
- Reduces pore pressure transmission through rock that allows to apply lesser mud density against conventional WBM.
- Mechanically seals micro-fractures and pore throats in shale and sand.

The hydration suppressant properties of the MAX-PLEX coming from the cation Al +++ is more effective compare to the cation K+ due the lower Ionic Radius (0.062 nm in average against 160 nm of the K+). Clay and gumbo inhibition is achieved by limiting water absorption and providing improved cuttings integrity. Effectively inhibits reactive clays and gumbo from hydrating and becoming plastic. Along with MAX-PLEX, the Per-Flex system also uses such a
component as NEW-DRILL that is partially hydrolyzed polyacrylamide (HPA) designed to
encapsulate cuttings and impart shale stability. NEW-DRILL acts as a protective colloid and
functions as a shale, cuttings, and well bore stabilizer. Other benefits include increased
lubricity, increased ROP, and decreased bit balling tendencies. This system is very
versatile and can be used in fresh, sea, or high salt systems. NEW-DRILL is compatible
with a wide range of fluid additives