JOINT INTERPRETATION OF TIME-LAPSE
GRAVITY DATA AND PRODUCTION
DATA FOR A GAS RESERVOIR

by

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ABSTRACT

Time-lapse gravity is commonly used to monitor fluid movement and is especially useful when monitoring water encroachment in a gas reservoir. Although time-lapse gravity has considerable resolution, it is beneficial to integrate different types of data to complement the time-lapse gravity interpretation. When monitoring water-influx in a reservoir, an increase in water yield in some wells may indicate increasing saturation values and suggest areas of fluid movement and density contrast change with time. These data can complement the time-lapse gravity analysis, the question to address is how to integrate these data appropriately to enhance the monitoring of the edgewater in a reservoir. The objective of this thesis is to develop a workflow to invert a time-lapse gravity data set and production data in the Sebei Gas field located in Western China and monitor the edgewater encroachment. Three time-lapse gravity surveys were conducted between 2011 and 2013 and were processed to estimate the error associated to the data set. Consequently, production data collected from 286 wells, was evaluated and plotted to determine its feasibility as complementary data for the time-lapse gravity inversion. To jointly interpret these two independent data sets, I converted the sparse production data into a time-lapse reference model that is subsequently incorporated as a guide into a generalized density inversion. To constrain the inversion result to a similar lithologic setting of the reservoir, I imposed spatially varying upper and lower density bound constraints for different depths of the model. Through this approach, I construct a set of density contrast models that are guided by the measured changes in gas/water yield, and whose distribution fits the time-lapse gravity data. The results of this work demonstrate that integrating the production data and setting lithology dependent bound constraints produced an improved definition of density changes. By doing a first order estimation of the porosity in the reservoir, I verified that the porosity estimated using the recovered density contrast of the improved model are more representative of the known porosity of the gas reservoir.
# TABLE OF CONTENTS

ABSTRACT ................................................................. iii
LIST OF FIGURES ......................................................... vi
LIST OF TABLES .......................................................... x
ACKNOWLEDGMENTS .................................................... xi
CHAPTER 1 INTRODUCTION .............................................. 1
CHAPTER 2 SEBEI GAS FIELD .......................................... 7
  2.1 Geologic Setting ................................................... 7
  2.2 Gas System Description .......................................... 10
    2.2.1 Reservoir Beds and Seal Rocks ............................ 11
  2.3 Porosity and Permeability ....................................... 12
  2.4 Hydrodynamic Factors ........................................... 14
  2.5 Summary .......................................................... 14
CHAPTER 3 MONITORING DATA ........................................ 18
  3.1 Time-lapse gravity data acquisition ............................ 18
  3.2 Time-lapse gravity data .......................................... 20
  3.3 Data Processing .................................................. 22
  3.4 Production Data .................................................. 29
  3.5 Summary .......................................................... 33
CHAPTER 4 QUANTITATIVE INTEGRATION ............................ 35
  4.1 Inversion Parameters ............................................ 35
LIST OF FIGURES

Figure 2.1  Carboniferous Petroleum system divisions of the Qaidam Basin located in Western China. The study area, the Sebei gas field, is shown in red. 8

Figure 2.2  Division of the structural units in the eastern and central Qaidam Basin. The study area, Sebei 1 is located in the eastern depression. 9

Figure 2.3  Stratigraphic column of the Quaternary Qigequan Formation in the Sanhu area. The main Quaternary stratum is what makes up the Sebei gas field. 9

Figure 2.4  Profile sketch across the reservoir of the main reservoir stratum. The shallow layers are composed of thick mudstone stratum and the reservoir layers are seen at 1.3 km depth. 10

Figure 2.5  Crossplot showing the interrelationships between porosity and permeability as a function of reservoir lithology in the Quaternary formation. 12

Figure 2.6  Change in porosity and permeability with depth of the aranaceous and argillaceous sediments in the Quaternary strata of the Sanhu area. 13

Figure 2.7  Schematic map (top) and cross section D-D’ (bottom) showing the hydrodynamics and gas migration direction in the Quaternary reservoirs in the Sanhu area. Sebei 1 and 2 are shown as the first gas pool. 15

Figure 2.8  Structural contour map of the K9 seismic reflectance surface in the Sebei 1 field. The gas-water contact is represented by the dashed contour line. 16

Figure 3.1  Residual gravity anomaly before gas reservoir was developed. The gravity low corresponds to the location of the gas reservoir, the amplitude of the anomaly low is approximately 1 mGal. 19
Figure 3.2  Time-lapse gravity difference for three epochs. The majority of the gravity change is occurring in the center of the reservoir where the wells are located and in the direction of the NW-SE survey lines. In the 2013-2011 epoch, a 30 µGal anomaly is seen throughout the entire reservoir region. A large anomaly is also noticeable in the southern part of the area. (a) 2011-2012. Black dots represent gravity stations (b) 2012-2013. Black dots represent gravity stations (c) 2011-2013 Black dots represent well locations. ................................. 21

Figure 3.3  The model space for the equivalent source layer with respect to the gravity stations (red circles). The model mesh is discretized finely in the center where the data is located and coarsely in the exterior  ............. 24

Figure 3.4  (a) Tikhonov curve for epochs 2012-2011(left), 2012-2013(center), 2013-2012(right) (b) Curvature for epochs 2012-2011(left), 2012-2013(center), 2013-2012(right) ................................. 26

Figure 3.5  Equivalent source result with the chosen optimal regularization parameter. 2011-2012 (left), 2012-2013(center), 2011-2013(right)  ............. 27

Figure 3.6  Histograms of noise estimates for each of the epochs. The standard deviation is shown in the top of each image in mGal. 8 µGal 2011-2012(left), 9 µGal 2012-2013(center), 10 µGal 2011-2013(right)  ... 27

Figure 3.7  Observed data (left), predicted data by equivalent source (center), observed and predicted difference (right) for 2013-2011 for all 919 gravity stations. Note the high amplitude difference anomaly of the right image in the southern part of the survey. ................. 28

Figure 3.8  Histogram of new noise estimates for 2013-2011 epoch. The standard deviation is 8 µGal  ...................... 29

Figure 3.9  Average production of water and gas for each survey year  .............. 30

Figure 3.10 Average production of water and gas for each survey year  .............. 31

Figure 3.11 Lateral distribution of water production difference for each epoch. This indicates water increase for each time period. ................. 32

Figure 3.12 Water and gas difference between 2013 and 2011 for each horizon and its respective depth  ...................... 33

Figure 4.1  Well location with respect to the 3D model space. Wells are shown in red.  .............. 39
Figure 4.2 Time-lapse reference model shown in different perspectives. The cut-off is 0.001 g/cc.

Figure 4.3 Resulting model of the upper constraints for each layer. The higher values that range from 0.3 g/cc to 0.25 g/cc were chosen to represent the producing layers with high permeability and porosity. The intermediate value is set to 0.1 g/cc, these correspond to layers who are producing gas but have a lower permeability value. The top layer was assigned with 0.02 g/cc due to prior knowledge of the area outside of the reservoir seen in Figure 2.4.

Figure 4.4 Inversion results of time-lapse gravity data over Sebei Gas field. All results are shown in the same color scale. The gray dots correspond to the -0.5 mGal contour of the residual gravity field representing an outline of the gravity low where the border of the gas reservoir is located. (a) using constant bound constraint (0-0.3 g/cc). (b) Using the reference model calculated from production data. (c) Using different bound constraints dependent on lithology (d) Using the spatially varying bound constraints and reference model.

Figure 4.5 Histograms of density contrast values recovered from inversion models. (upper-left) using constant bound constraints (0-0.3 g/cc). (upper-right) Using spatially varying bound constraints dependent on lithology. (lower-left) Using the reference model calculated from production data. (lower-right) Using the spatially varying bound constraints and reference model.

Figure 4.6 Profile parallel to 5550 m northing of each inversion result with the same colorbar. (top-first) using constant bound constraints (0-0.3 g/cc). (second) Using time-lapse reference model calculated from production data. (third) Using spatially varying bound constraints dependent on lithology. (fourth) Using spatially varying bound constraints and time-lapse reference model.

Figure 4.7 3D Saturation models calculated with reservoir volumes. All models cut-off is 0.01. (a) Gas saturation 2011. (b) Gas saturation 2012. (c) Water saturation 2011. (d) Water saturation 2013.

Figure 4.8 Porosity values at at 625 meters of depth. (upper-left) using constant bound constraints (0-0.3 g/cc). (upper-right) Using spatially varying bound constraints dependent on lithology. (lower-left) Using the reference model calculated from production data. (lower-right) Using the spatially varying bound constraints and reference model. The porosity values calculated using the different bound constraints and the reference model are lower due to the imposed bound constraints.
Figure 4.9  Porosity values at 775 meters of depth. (upper-left) using constant bound constraints (0-0.3 g/cc). (upper-right) Using spatially varying bound constraints dependent on lithology. (lower-left) Using the reference model calculated from production data. (lower-right) Using the spatially varying bound constraints and reference model. An important feature to note in the lower left image of Figure 4.9 are the porosity values in the middle of the area that range from 0.20 to 0.30. This distribution appears only when using the inversion result that integrates the reference model. This indicates that the time-lapse reference model calculated from production data has an impact on the estimation of porosity distribution.

Figure 4.10  Average porosity values with depth. The blue points represent the porosity estimates calculated using the inversion results of the first model (only using time-lapse gravity data). The red positives represent the porosity estimates calculated using the inversion results of the latter model (using the spatially varying bound constraints and reference model). Results show that at shallow depth the estimates differ significantly. The improved model (red positives) estimates lower porosity in the shallow layers due to the bound constraints that were imposed as mudstone in the first layer. The porosity values are higher for the deeper reservoir layers. This result is consistent with the lithologic model used in the inversion algorithm.
LIST OF TABLES

Table 4.1  Values of fluid and reservoir properties from different sources . . . . . . . . 38

Table 4.2  Average porosity values calculated using the density contrast values of various inversion results. The elements used in the inversion are indicated for every result. . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 54
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CHAPTER 1
INTRODUCTION

Natural water driven reservoirs are known to be some of the most effective oil and gas producing fields in the world [Roadifer, 1987]. The reason is that the reservoirs are either bounded by or in direct contact with a water source. As reservoir pressures decrease during production, these waters can naturally encroach into the reservoir, thus counter the pressure drop and drive the remaining hydrocarbons to the producing wells.

To maximize the benefit of this natural water drive, an operator needs to understand the overall scale of this water source, the communication it has with the reservoir, the distribution of porosity and permeability, and the changing levels of water encroachment throughout production. While natural water drive can result in efficient recovery, it can also lead to a rapid increase in water production and therefore early shut down of producing wells. The excessive production of water can also cause problems such as corrosion, gas hydrate formation, and the complicated disposal of the water itself. For these reasons, as well as economics, excess water production is not desirable. The strategy in such cases is to monitor the encroaching water and adjust production to minimize overall water cut. For example, if there is a strong edge-water drive, such as the site studied in this thesis, an operator may choose to systematically shut down producing wells along the edge of the reservoir. Direct observations of production data (gas and water yields) at each well is the primary monitoring tool in most cases. However, to obtain information about the water presence between the wells and at a certain distance of well heads, geophysical monitoring techniques must be additionally employed.

In this study, I consider the Sebei Gas field located in western China. This reservoir has been developed since 2004 by China National Petroleum Corporation. The Sebei gas field is an multi-layered sandstone reservoir and has an area of approximately 40 km² at
500-1,300 m depth range [Liu and Zhao, 2014]. Currently, the Sebei gas field is in the late stage of the production plateau, with an increasingly obvious decline in production due to the excessive water production around the edge of the gas reservoir. Proportional production from separate zones is a preferred strategy to stabilize the production [OU, Chengu; Wang, 2016], therefore understanding the water activity around the gas reservoir has become an urgent issue.

Time-lapse reservoir monitoring is vital in understanding reservoir conditions and is considered an important component of geophysical techniques. While this area is dominated by time-lapse seismic, there is benefit to incorporating additional less-expensive methods that can complement the seismic data, particularly for reservoirs where the seismic data are not available due to the cost or environmental challenges. Feasibility studies based on detailed reservoir model and robust inversion of realistically simulated data shows that time-lapse gravity surveys may contribute to improved production efficiency and reservoir management in-between the more traditional, and expensive 4D seismic surveys (Krahenbuhl and Li [2012], Eiken et al. [2008], Young and Lumley [2012]).

The means of time-lapse (4D) gravimetry is to determine spatio-temporal changes of the Earth's gravity field by performing repeated measurements of gravity and spatial gravity gradients. Given the accuracy of a time-lapse gravity measurement, it is of interest to approximately quantify the vertical resolution in terms of the density change, depth and horizontal extent. It has been proved that the peak amplitude of the surface response of of CO$_2$ movement can reach up to 40 $\mu$Gal for depths in the range of 950m - 1050m and a radius of approximately 750 meters [Krahenbuhl et al., 2010]. In regards to the Sebei Gas field, the reservoir size and depth are well within the range of the sensitivity of the time-lapse gravity signal. Certainly many combinations of densities, porosity and change in the saturation can result in the same bulk density change. In this study, I will investigate a two-phase case where water replaces gas. For a gas-water replacement with an average of 30% porosity, the estimated value of density change is 150-300 kg/m$^3$. This density variation, considering
the depth, radius and thickness of the Sebei reservoir can have peak amplitudes of gravity surface response higher than $100 \mu$Gal. Time-lapse gravity variations are proportional to the bulk density changes, therefore, the larger the porosity, the difference in phase densities and change in the saturation, the larger the gravity variation. For this reason, time-lapse gravity measurements are especially valuable for monitoring water encroachment in a gas reservoir.

The observed temporal gravity variations is an integrated effect of all mass redistribution below the observed point. The signal not only contains the property change of interest but also additional signals induced by various environmental processes. Since time-lapse gravity data need significant data accuracy, it is important to identify the major noise sources that contribute to the error. In practice, the current achievable measurement uncertainty of the relative gravity meter is about $5 \mu$Gal [Gettings et al., 2008]. The noise sources include instrument drift, earth tide corrections, sensitivity to height changes, hydrological effects related to the movement of the water table [Gettings et al., 2008]. Most of these effects need to be reduced with advanced acquisition techniques in order to produce a good quality data signal. Other than instrument drift and tides, the remaining corrections are static over time and naturally removed when two data sets are subtracted from each other [Davis et al., 2008]. Therefore, one only needs to apply the drift and tidal corrections to the individual surveys to create difference maps that capture the change of gravity over time resulting from subsurface mass change.

Reservoir monitoring is usually associated to history matching tools and production data that are analyzed simultaneously. Production data are probably the most valuable and widely available pieces of data from a petroleum engineer’s point of view and used in geophysics as an indicator tool for certain scenarios. For a water-flood reservoir, determining the ratio of the rate of water production to the rate of gas production is in many respects similar to determining the concentration in a tracer test. Water can be thought of as a tracer, whose concentration is measured at the production well [Oliver et al., 2008]. Strong water drives are characterized by small changes in the producing gas and water, therefore, the difference
in gas and water yield can be a helpful indicator for strong aquifer encroachment.

Recent improvements in instrumentation and data-acquisition have made time-lapse gravity a mature monitoring technique, both for land and offshore applications. Such data are complementary to seismic data and, when properly constrained by other subsurface information, can add significant value to exploration and 4D monitoring applications. For example, the time-lapse gravity study of Brady, Ferguson, Hare and colleagues at Prudhoe Bay, Alaska, proved highly successful in monitoring movement associated with gas cap water injection [Brady et al., 2004]. There are various feasibility studies that analyze water-driven reservoirs and different patterns of water influx. Young and Lumley study the feasibility of time-lapse gravity monitoring producing gas fields in the Northern Carnarvon Basin, Australia [Young and Lumley, 2012]. They concluded that for a strong water-drive gas reservoir, a field-wide height change in the gas-water contact greater than 5 m may produce a coherent gravity response depending on the reservoir depth and rock quality. Stenvold, Eiken and colleagues compare the gravity response of water entering edgewise with water entering via a basal aquifer.[Stenvold et al., 2008a]. The study done in the Troll field, uses gravity and depth measurements to monitor gas production [Eiken et al., 2008]. This study identified significant changes over parts of the field, which are likely to have caused mainly by edgewater influx. It is common for time-lapse studies to include production data to infer changing saturation values and calculate a total mass change to estimate the water that has encroached into the reservoir [Eiken et al., 2008]. Glegola, Ditmar and colleagues investigate the added value of gravimetric observations for gas-field-production monitoring and aquifer support estimation. They perform a numerical study to infer aquifer-support characteristics using the time-lapse gravity and pressure data assimilated jointly. Results show that combining pressure and gravity data may help to reduce the non-uniqueness problem and provides a more accurate reservoir-state description [Glegola et al., 2012]. This result echoes a most recent outlook of gravity data; it is useful to jointly interpret gravity data with other sets of data to maximize understanding of water movement. An integrated interpretation
of two or more sets of data that support reservoir monitoring, such as pressure information or saturation values, gives a more consistent understanding and a more constrained inverse solutions.

Despite the increasing number of applications of time-lapse gravimetry for the monitoring of hydrocarbon reservoirs, there is little published material on the added value of gravimetric observations within a broader context of modern reservoir engineering, such as in closed-loop reservoir management. The potential contribution of gravity data for an improved reservoir characterization, production forecast accuracy and hydrocarbon reserves estimation, is still to be addressed in more detail.

In this thesis, I present an analysis of time-lapse gravity and production data acquired in Sebei Gas field in China [Liu and Zhao, 2014]. Currently, the field is in the late stage of the production plateau. It is therefore important to identify zones of high water flux which may cause a decrease in gas yield. I begin here with an introduction of the water flux problem and motivation for using time-lapse gravity and integrating production data as a possible workflow for reservoir monitoring. In the following chapter, I provide a brief overview of the theory behind time-lapse gravity resolution. I also discuss the signal levels that must be achieved for difference scenarios and what the common time-lapse gravity noise sources for monitoring a gas reservoir.

I begin to explain the geologic setting of the Sebei gas field and its geologic structure in Chapter 2. In any study, understanding of the reservoir’s geology is important. The entire outer area of the reservoir must be scrutinized carefully to identify communicating and non-communicating pathways; communicating pathways represent possible water entry points. Structure maps are considered to identify the reservoir trap and the trapping surface. Additional information of the lithology pattern and layers of high permeability should be identified. I describe the main lithologic units and permeability-porosity distribution that characterize the various layers.
Furthermore, I describe the time-lapse gravity data acquisition and processing in chapter 3. The time-lapse gravity data in this thesis corresponds to the study done by Liu and colleagues presented in the Society of Exploration Geophysics in 2014. They describe an advanced acquisition technique that shows better results for time-lapse gravity monitoring [Liu and Zhao, 2014]. I explain the key aspects of the acquisition and how the survey increases the data quality. In this chapter, I explain the error estimation for the time-lapse gravity data. I use an equivalent source technique to estimate the errors in the data and find standard deviation associated with the noise signal. In addition to three sets of surface gravity data, I describe the production data from 286 wells throughout the field. The analysis helps identify the validity of using the production data as quantitative information to guide the time-lapse gravity inversion.

In chapter 4, I describe the quantitative integration of the time-lapse gravity data and production data in the inversion methodology. To jointly interpret these data, I construct a 3D representation in form of a reference model, from sparsely distributed production data that represents the changing water flood over each epoch. In order to incorporate geology information I set specific bound constraints for different layers of the 3D model. In chapter 4, I use the reference models from the second step to guide the inversions of the time-lapse gravity data and demarcate the regions of positive density change from water-gas replacement. As a simple verification, I convert each recovered time-lapse density into an estimate of porosity distribution in the field. By integrating the production data, I am able to present a more detailed model that recovers higher density contrasts, thus providing a better estimate of the true porosity of the field.

Finally, I discuss the relevance of the time-lapse gravity results for reservoir monitoring by summarizing the general conclusions presented in Chapter 4.
CHAPTER 2
SEBEI GAS FIELD

In this chapter, I present geologic information of the Sebei Gas field where the time-lapse gravity measurements were taken. The purpose of analyzing the geologic background and different reservoir characteristics is to understand the context of the geologic problem in order for the geophysical methods to obtain proper meaning. It is useful to know these geologic features in order to use them as background information for future inversion modeling. Therefore, with more information input, the model can generate a more accurate understanding of the density change occurring.

To begin, I explain the general structure and position of the Sebei gas field within the Qaidam basin. The geologic setting is followed by a description of the gas system, which indicates the reservoir beds and seal rocks. An important part of this chapter is describing the distribution of porosity and permeability in the gas reservoir. This analysis will be meaningful when calculating different input parameters of the inversion.

To end the chapter, I explain the hydrodynamic factors that affect the water-driven gas reservoir. Understanding the source and the direction of water influx helps indicate the expected areas of high water production volumes and/or high density contrast values.

2.1 Geologic Setting

The Sebei gas field features a unique geological setting for analyzing time-lapse gravity measurements. The Sebei gas field is one of the largest typical multi-layered sandstone reservoirs and one of the major gas producing areas of Northwest China. Located in the Northern Qinghai-Tibetan plateau, the Qaidam basin is a large-scale Cenozoic intermontane basin, with its area of 119,916 km². Figure 2.1 shows the divisions of the different carboniferous petroleum systems present in the basin. It also shows that the Qaidam Basin is bounded by three major mountain ranges: Kulun, Qilian and Altun Mountains. Figure 2.2 shows
the three first order structural units based on basement structure and sediment covers. The basement structure can be divided into three structural units: a northern margin fault-fold belt, and the eastern and western depressions [Dang et al., 2008]. Granite, gneiss, and green schist occur in the basement of the eastern and western depressions [Dang et al., 2008]. The Sebei gas field is located in the eastern depression on the northern slope. The eastern depression, with an area of approximately 37,000 km$^2$ contains a non-marine sedimentary sequence dominated by lacustrine clastic rocks.

Figure 2.1: Carboniferous Petroleum system divisions of the Qaidam Basin located in Western China. The study area, the Sebei gas field, is shown in red. [Chenglin and Gang, 2011]

The thickness of the Quaternary sediments is in the range of 1,500 to 2,000 m with a sedimentary rate around 0.6 to 0.7 mm per year [Dang et al., 2008]. The Qigequan Formation is the main Quaternary stratum in the Sanhu area with an average thickness of 1,700 m. It can be divided into 14 units, based on seismic reflectance features. All of the gas plays discovered in the Sanhu area are within the Qigequan Formation Figure 2.4.
Figure 2.2: Division of the structural units in the eastern and central Qaidam Basin. The study area, Sebei 1 is located in the eastern depression. [Dang et al., 2008]

![Map of structural units in the Qaidam Basin](image)

<table>
<thead>
<tr>
<th>Era/zone</th>
<th>System</th>
<th>Series</th>
<th>Qigewan Frm.</th>
<th>Division Symbol</th>
<th>Seismic Standard Bed</th>
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Figure 2.3: Stratigraphic column of the Quaternary Qigequan Formation in the Sanhu area. The main Quaternary stratum is what makes up the Sebei gas field. [Dang et al., 2008]
A multi-layered sandstone reservoir such as this one possesses several distinct geological features from those of conventional sandstone reservoirs, these include multiple interbedded thin-layered sandstone and mudstone beds, shallow marine depositional environments and stable sedimentation with good lateral connection. Figure 2.4 shows the geologic features of this type of gas reservoir [He et al., 2015]. It shows multiple layers of interceded sand and mud, stable sand body microfacies, reservoir facies with high permeability and porosity heterogeneity. The shallow layers are composed of thick mudstone stratum and the reservoir layers are seen at 1.3 km depth. These features will be important when understanding the 3D model and allow for more detailed interpretation of the gravity signal.

![Figure 2.4](image)

Figure 2.4: Profile sketch across the reservoir of the main reservoir stratum. The shallow layers are composed of thick mudstone stratum and the reservoir layers are seen at 1.3 km depth. He et al. [2015]

### 2.2 Gas System Description

The Sebei gas field is approximately 45 km² in area and has an asymmetrical long elliptical shape with the long axis extending to the northwest. The long axis of the anticline measures 1.2-14.9 km, and the short axis measures 4.8 - 5.9 km, indicating a syndepositional anticline. The hydrocarbon trap amplitude of the gas reservoir is approximately 100 m and the depth at the top is 1,200 m [He et al., 2015].
It is important to describe the gas system in this reservoir and identify the type of gas that is being produced in order to estimate an appropriate density associated with the gas in the system. The Sebei field is known to produce biogenic methane which forms early in a basin’s history at low temperatures. The origin of biogenic gas differs from the more abundant thermogenic gas derived from cracking kerogen and/or previously generated liquid hydrocarbons, because the biogenic gas has a bacterial origin [Katz, 1995]. However, the organic richness in these Quaternary sediments is relatively low, with little organic matter (0.1% total organic count TOC) in sandstones. Since the TOC is very low, the effective source rocks for the biogenic rocks can be explained by a cryogenic climate and the hyper salinity of the lake waters preserving the primary organic matter which delays the peak biogenic gas generation in the area [Dang et al., 2008].

2.2.1 Reservoir Beds and Seal Rocks

The reservoir beds in the Sebei field are primarily Quaternary beds with the aranaceous rocks (sand sheets and small sand bars) that amount to 16-28 % of the sedimentary column [Dang et al., 2008]. The upper and lower surfaces of the sand bodies extend widely but are well confined by the geologic structure [OU, Chengua; Wang, 2016]. The sand body microfacies consisting of a sand sheet, sand bar and mud bank control the reservoir porosity and permeability distribution. The sand sheet is a partial reservoir with dolomite, microlite and schistic infill, while the sand bar is a reservoir where the compaction and infilling has partially damaged the porosity [OU, Chengua; Wang, 2016]. The properties of different layers change abruptly with high heterogeneity [OU, Chengua; Wang, 2016]. If these layers of impermeable and permeable reservoir can be correctly identified, this information will be useful for the vertical variation of density contrast seen in the time-lapse gravity inversion. The Quaternary mudstones in the study area are characterized by poor consolidation and relatively high porosity [Pang et al., 2005]. Regularly, mudstones are dominated by fine-grained clay minerals which have smaller pore size and a high breakthrough pressure. These are considered dynamic seals that are created because of permeability characteristics.
Hydraulic seals occur when water saturation levels of the Quaternary mudstones are up to 80-99%. When the pores are filled with water composed of high salinity, the gas permeability of the mudstone is drastically reduced. There are also hydrocarbon gradient seals which are mudstones that serve as both source rocks and caprocks for the biogenic gas. Methane diffuses from high concentrations to low concentrations, and this can stop or slow down the vertical flow of methane from the underlying rocks, thus forming a gas seal by the hydrocarbon concentration gradient. The presence of thick mudstone, anhydrite and halite above the vertically stacked gas plays provides regional caprocks for the biogenic gas [Pang et al., 2005].

2.3 Porosity and Permeability

This reservoir has a distinct porosity and permeability relationship. Literature indicates that porosity averages 25% to 40% (Pang et al. [2005], Dang et al. [2008], He et al. [2015],) while the permeability ranges from 10 to 2694 mD with an average of 595 mD.

Figure 2.5: He2015

Crossplot showing the interrelationships between porosity and permeability as a function of reservoir lithology in the Quaternary formation.[He et al., 2015]
Figure 2.5 demonstrates a large range of porosity and permeability which vary with lithology, these values were taken from core samples taken by the Qinghai Oilfield Company of the field [Pang et al., 2005]. For example, the Quaternary mudstone has a limited range of permeability but it’s porosity varies from 23% to 37%. The variation in porosity and permeability is also a function of burial depth for arenaceous and argillaceous rocks in the Sanhu gas field area [Dang et al., 2008]. Figure 2.6 shows the change in porosity and permeability for both arenaceous and argilaceous rock in the Quaternary strata of the Sanhu area. These estimates were taken from drilling results. [Dang et al., 2008]. The porosity of the arenaceous rock varies from 26%-42%, while the porosity of the argillaceous rock varies from 23% - 40%. On the contrary, the permeability of the arenaceous rock compared to the argillaceous rock can be up to two orders of magnitude different. It is important to identify which layers are permeable enough to permit water-gas replacement and therefore generate high density contrast. Permeability and porosity indicators will be used as a priori information for inversion constraints. This will be further explained in 4.

Figure 2.6: Change in porosity and permeability with depth of the arenaceous and argillaceous sediments in the Quaternary strata of the Sanhu area.
2.4 Hydrodynamic Factors

The field is a water-flooding gas field with simple structures and a low reservoir trap closure. In general, the field consists of gas beds, gas-water beds and pure water beds. Originally, gas and water were distributed at high elevations in the southwestern area and at low elevations in the northeastern area. The distribution of gas and water is controlled not only by structures but also by hydrodynamic factors. The major water source of the area is the surrounding Kulun Mountains which are located in the southwestern part of the Qaidam Basin. The well-developed glaciers provide high precipitation and major recharge in area. The surface water recharges the deeply buried formations and passes through the Gobi conglomerate layer forming a water-circulation system flowing from the southwest to the northeast [He et al., 2015]. Figure 2.7 shows a cross-section of the formations in the Qaidam Basin and the arrows indicate the hydrodynamic direction. The cross-section location is shown in the schematic map at the top of the figure.

Figure 2.8 shows the well logs for 6 wells in the area located in profile B-B’. The yellow highlighted layers represent the reservoir layers which are considered to be gas pay. The bottom half of Figure 2.8 indicates where the water-gas contact is located with respect to the structure contours of the anticline field. The water system causes the gas-water contact to be inclined. Within the gas field, the contact elevation difference can reach up to 30 to 40 m. Due to poorly developed fissures and faults, almost no vertical breakthrough of water flow can occur in the gas-water-bearing wells, but lateral breakthrough is possible (He et al.). In the gas field, edge water bursting may occur which would lead the gas output to decrease substantially. Therefore, it is important to monitor edgewater fronts that are causing high pressure zones and increased density contrast in the gas reservoir.

2.5 Summary

In this chapter, I described the geologic setting, gas system and hydrodynamic factors of the Sebei gas field. The reservoir is located in the Qaidam Basin in western China, it is one
Figure 2.7: Schematic map (top) and cross section D-D’ (bottom) showing the hydrodynamics and gas migration direction in the Quaternary reservoirs in the Sanhu area. Sebei 1 and 2 are shown as the first gas pool. Dang et al. [2008]
Figure 2.8: Structural contour map of the K9 seismic reflectance surface in the Sebei 1 field. The gas-water contact is represented by the dashed contour line. Dang et al. [2008]
of three gas reservoirs in the area that produce gas that are of biological origin. The Sebei field has an asymmetrical long elliptical shape with approximately 9 km long and 5 km wide and covers an area of approximately 40 km$^2$. It has a syndepositional anticline structure and the main reservoir layers are located between 500m-1300m in depth. The Sebei field is known to be a multi-layered sandstone reservoir and includes interbedded mudstone layers and the major gas reservoir has seven pay beds with gross thickness of approximately 700 m. Since the reservoir consists of mudstone and sandstone layers, the permeability and porosity values change depending on the depth of a given layer. I presented an analysis of porosity and permeability for different lithologies and how the values change with depth. The average porosity of the entire reservoir given by the published literature is 30% while the permeability ranges from 0.05 mD to 1000 mD. This analysis will be meaningful when evaluating model results and help predict zones of high-density contrast. At the end of this chapter, I explained the hydrodynamic factors that affect the water-driven gas reservoir. Understanding the source and the direction of water influx helps indicate the expected areas of high water production volumes and/or high density contrast values.
In chapter 2, I explained the Sebei gas field’s geologic and reservoir setting, in this chapter I will analyze the data used to monitor the water-gas substitution in its setting. I will start by describing the time-lapse gravity acquisition and processing. The time-lapse gravity acquisition study introduces a new approach using a relative gravimeter to monitor water around a gas reservoir. This new approach helps the accuracy and precision of the gravity measurements, which leads to more credible data.

Once there is a clear understanding of the time-lapse gravity data, the next step is to extract the coherent signal by removing noise. It is also important to note that data processing is required to be consistent among the three epochs in order to assure that all of the noise is characterized in the same manner. To meet these requirements I use the equivalent source technique, a well established method that can be used to process potential field data. In this case, I will use this method for the time-lapse gravity data processing and estimate the noise in each epoch. Another aspect of this chapter is the description of production data. I will first present a first order analysis of gas and water production of the area and then compare the observations with the time-lapse gravity data set.

3.1 Time-lapse gravity data acquisition

To monitor the water encroachment at the Sebei gas field, three sets of time-lapse gravity data were collected on the surface in the years of 2011, 2012, and 2013 [Liu and Zhao, 2014]. A total of 919 gravity stations across 19 surveys lines with a line spacing of 500 m and a station spacing of 200 m were used. The location of the stations are seen in Figure 3.1. The grid seen in the background of Figure 3.1 represents the residual gravity data, bouguer corrected gravity, before the gas reservoir was produced. The low anomaly of -1.5 mGal shows where the gas reservoir is located.
Figure 3.1: Residual gravity anomaly before gas reservoir was developed. The gravity low corresponds to the location of the gas reservoir, the amplitude of the anomaly low is approximately 1 mGal.

In the introduction, I demonstrated that the data precision must satisfy about 10 $\mu$Gal in order to obtain a credible time-lapse gravity anomaly to monitor water substituting gas at a given reservoir depth. The depth of the main gas producing layers are at 800m-900m, which suggests that this reservoir is sufficiently shallow for the time-lapse gravity sensitivity.

A Scintrex CG-5 meter was used to acquire data at every station during the three surveys. The Scintrex instrument is a quartz spring meter and is frequently used because it offers the fastest, most portable measuring method for land surveys. It is a relative gravimeter that suffers from instrument drift caused by the stretching of the spring with time. The drift is approximated with a polynomial function over time with the repeated measurements made at the same base station. The CG-5 instrument accuracy reaches 1 $\mu$Gal and can reach precision better than 2-3 $\mu$Gal [Christiansen et al., 2011]. These facts are relevant because time-lapse measurements that monitor fluid flow require high precision observations. In order to improve measurement precision, Liu and colleagues adopted several techniques that were stated in their publication [Liu and Zhao, 2014].
The new techniques for time-lapse gravity measurements include measuring on a fixed cement piles in each of the general time-lapse gravity stations and base stations. Also, the gravity base stations were guaranteed to be the same for the entire survey and still readings were acquired using a long baseline procedure. The procedure consists of using fixed locations of base stations along a line 30 km in length, far away from the gas reservoir development area. The gravity anomaly of the reservoir was then normalized to the values of the remote fixed base stations on the long stable baseline. In order to obtain multiple observations for each station, an orthogonal observation acquisition was performed in which a station was observed along one direction and then the same station was observed along the perpendicular direction, so each general station had two observation values acquired using two different routes. The average value of both observations was assigned as the gravity value of that station. When the difference between two repeated observation values of a general station was greater than the specified error tolerance, an observation was repeated for the third time. The average of the two repeated values among the three whose difference was less than specified error was used as the final observed gravity value for this station.

Gravity-monitoring was conducted in July 2011, August 2012, July 2013. Acquiring the gravity measurements at the same time each year reduces the hydrological effect of the gravity measurement caused by climate variation. The measured results of the three years have no regular variation or trend in elevation, which shows that the gas reservoir development has not caused significant subsidence. The improved acquisition procedures mitigate noise sources such as hydrological changes as well as height change and drift effects. This acquisition technique laid a foundation for improving the observation accuracy of the survey and reassure good quality time-lapse gravity data.

3.2 Time-lapse gravity data

In this section I will introduce the results of the time-lapse gravity measurements by showing the gravity difference between 3 years in 3 different epochs 2011-2012, 2012-2013, and 2011-2013.
Figure 3.2: Time-lapse gravity difference for three epochs. The majority of the gravity change is occurring in the center of the reservoir where the wells are located and in the direction of the NW-SE survey lines. In the 2013-2011 epoch, a 30 µGal anomaly is seen throughout the entire reservoir region. A large anomaly is also noticeable in the southern part of the area. (a) 2011-2012. Black dots represent gravity stations (b) 2012-2013. Black dots represent gravity stations (c) 2011-2013 Black dots represent well locations.
Figure 3.2(a) displays the difference in gravity between the 2011 and 2012 surveys. The maximum value of gravity difference is 50 $\mu$Gals for this time period. The data display some noise in the grid, but in general, the anomalies located in the middle have spatial continuity. Figure 3.2(a) shows a general dispersion of high values in green in the middle of the survey area and surrounding low values of 0 to -10 $\mu$Gal in blue.

Figure 3.2 shows all three grids which were generated with the same grid interval and same color scale. Figure 3.2(b) shows time-lapse gravity incremental anomaly of the work area monitored from 2012 to 2013, the maximum value in this epoch is 90 $\mu$Gal. Figure 3.2(b) shows a gravity anomaly of approximately 60 $\mu$Gal in the center of the survey area. This gravity anomaly is oriented in the NW-SE direction and parallel to the lines crossing the survey area in the NW-SE direction. This anomaly is similar to the anomaly seen in Figure 3.2(a). In addition, there is a large anomaly in the southern part of the study area that corresponds to a high of 90 $\mu$Gal. This anomaly is not shown in Figure 3.2(a) indicating that this anomaly appeared in the 2013 survey.

Figure 3.2(c) shows time-lapse gravity anomaly increment from 2011 through 2013, this figure shows the summation of the gravity difference in Figure 3.2(a) and Figure 3.2(b). The maximum value of time-lapse gravity increment anomaly is approximately 90 $\mu$Gal. The large anomaly seen in the center of Figure 3.2(c) has now expanded and increases in amplitude. The high gravity difference seen in green is surrounded by a lower difference seen in blue. There are small anomalies in the well location area that correspond to 70-80 $\mu$Gals. The two-year difference (2011-2013) emphasizes the outlying anomaly seen in the southwestern part of the survey area. Figure 3.2(c) shows where the wells are located in the field. The outlying anomaly is relatively distant from the production wells and therefore cannot be directly related to the water production.

### 3.3 Data Processing

Before inverting the time-lapse gravity data it is necessary to calculate the data error. I use the equivalent source technique to estimate the data error for the three different epochs.
Equivalent source method was first presented by [Dampney and City, 1969], and has since been demonstrated as a valuable and versatile tool for the processing of potential-field data [Li, 2001].

The goal of the equivalent source construction is to calculate an imaginary source layer that can reproduce all data observed. For time-lapse gravity data, the layer must be composed of density varying laterally and placed at some distance below the observation surface. This is carried out by discretizing the density layer into a set of continuous cells and assume each cell has a density value. These density values are expressed in the following model vector:

\[ \vec{\rho} = (\rho_1, \ldots, \rho_M) \] (3.1)

For this layer the upper and lower bounds of this vector is set to 0 g/cc and 0.3 g/cc respectively. The mesh I use to construct the equivalent source layer is placed in an area slightly larger than the data area. The layer is placed 700 m under the observation surface. It consists of a total of 4,488 cells, 66 of the cells in the easting direction and 68 cells in the northing direction. The finer cells located in the survey area measure 200 m and the cells located outside the survey area are courser and measure 500m-1000m. One cell represents the thickness of the layer which is 250 m. Figure 3.3 shows the mesh with respect to the time-lapse gravity data points.

Since the gravity field is linearly related to the density values in the model, the following equation relates the model density values with the reproduced gravity field:

\[ \vec{d} = G\vec{m} \] (3.2)

where \( G \) is the coefficient matrix, whose elements \( g^{ij} \) define the contribution of \( j^{\text{th}} \) cell with unit density value to the \( i^{\text{th}} \) datum and \( \vec{d} \) is the vector of observation data. The equivalent layer is inverted by solving a minimization problem:

\[ \phi = \phi_d + \phi_m \beta \] (3.3)
where $\beta$ is the regularization parameter that determines the trade-off between how well the equivalent source reproduces the data represented by the data misfit ($\phi_d$) and the complexity of the model given by the model objective function ($\phi_m$).

The next step to this process is determining the optimal value of $\beta$. Once the optimal solution is calculated, the noise standard deviation is estimated from the difference between the observed and predicted data, which is the denoised data. There are a number of approaches for estimating the optimal value of the regularization parameter. I chose a commonly used approach known as L-curve criterion [Hansen, 2001] because it is a more convenient visualizing tool for displaying the trade-off between the size of the regularized solution and its fit to the given data as the parameter changes [Li, 2001]. When plotting the norm of the least squares solution as a function of the data misfit for each regularization parameter, the L-curve exhibits a corner that appears like an L, hence the name L-curve. As the regularization parameter value decreases towards this corner, the model norm changes are diminutive.
compared to the decrease of the data misfit value. The L-curve criterion considers the corner point to be the optimum value which balances extracting the right amount of signal and where the data is being least affected by noise. This curve is obtained by solving the equivalent source layer for a range of different values of $\beta$. Since the problem is a generalized Tikhonov regularization, this curve is also called the Tikhonov curve.

There are different limitations to the L-curve criterion that should be pointed out in this analysis. There is an asymptotic behavior in the L-curve as the number of data increase. This method becomes complex because the linear system depends on the discretization method (size and shape of mesh) as well as the way the noise enters the problem. I experimented with different discretizations and ranges of regularization parameters in order to obtain a recognizable shape of an L-curve.

Figure 3.4(a) shows the three Tikhonov curves for the epochs 2011-2012, 2012-2013, 2011-2013. The bottom row of images show the corresponding curvature, where the maximum curvature is identified with respect to the $\beta$ parameter. In the first epoch, the maximum curvature corresponds to a $\beta$ value of 621.

The next epoch has an L-curve with a different characteristic corner, where the maximum curvature is located where the $\beta$ value is 868. The curvature plot in the 2012-2013 epoch shows abnormal peaks in the calculation indicating that the inversion has some instability for these values. Also, the corner in this L-curve is not as explicit as the other epochs, however, the curvature calculation does identify a maximum curvature that is close to the sutil corner of the corresponding L-curve. The plots for 2011-2013 epoch show a clear corner and a maximum curvature corresponding to a $\beta$ of 356. The resulting layers by using the optimum $\beta$ parameter for each inversion are shown in Figure 3.5.
Figure 3.4: (a) Tikhonov curve for epochs 2012-2011(left), 2012-2013(center), 2013-2012(right) (b) Curvature for epochs 2012-2011(left), 2012-2013(center), 2013-2012(right)
Figure 3.5: Equivalent source result with the chosen optimal regularization parameter. 2011-2012 (left), 2012-2013(center), 2011-2013(right)

Figure 3.6: Histograms of noise estimates for each of the epochs. The standard deviation is shown in the top of each image in mGal. $8 \mu$Gal 2011-2012(left), $9 \mu$Gal 2012-2013(center), $10 \mu$Gal 2011-2013(right)

Figure 3.5 shows the equivalent source layers constructed from each of the 3 epochs. The optimal equivalent layers illustrated in Figure 3.5 was selected according to the L-curve criterion and fits the coherent signal in the observed data. The equivalent source results shows a smooth signal due to the inability of the equivalent source layer to reproduce the high-frequency signal that are characteristic of noise.

Histograms of the estimated standard deviations are shown in Figure 3.6 for each epoch. The histogram show a gaussian distribution and the standard deviation is indicated on the top of the image. The error estimation for the 2011-2012, 2012-2013, and 2011-2013 is $8 \mu$Gal, $9 \mu$Gal, and $10 \mu$Gal respectively.
Figure 3.7: Observed data (left), predicted data by equivalent source (center), observed and predicted difference (right) for 2013-2011 for all 919 gravity stations. Note the high amplitude difference anomaly of the right image in the southern part of the survey.

Figure 3.7 shows the original observed data, the denoised by the equivalent source and difference of observed and denoised for the 2013-2011 epoch. The figure shows a 90 µGal difference that corresponds to the observed anomaly located in the southern part of the survey. This anomaly seems to cause the biggest error in the data and can possibly skew the error statistics. To test if the error calculation is significantly affected by the outlying anomaly, I removed 6 stations that caused the high anomaly from the initial equivalent source data set. Figure 3.8 shows a new histogram with the error statistics after the calculation without the 6 stations. The new standard deviation is 8 µGal, compared to the standard deviation of 10 µGal calculated previously.

Although the standard deviation calculated before and after removing the 6 data stations are relatively different, I want to analyze the entire data set without removing significant amount of stations. Because the feature is embarks a relatively small amount of cells compared to the total amount of cells used in the entire model, the inversion will not be highly affected by this. I will not eliminate this data and proceed using the original error estimate. This will be further explained in Chapter 4.
3.4 Production Data

Production data analysis has been used as reservoir management tool to evaluate well performance and predict future potential of oil and gas reservoir [Elgmati, 2015]. In a producing gas reservoir with strong water drive, the gas saturation will decrease in zones of water influx. This water influx can be detected in early analysis by the increasing amount of water a group of wells are producing. By evaluating the spatial and temporal changes in water and gas yield, there is an indication of density changes and the source of time-lapse gravity anomalies.

Production data was collected from 286 wells that produce a total of 6 horizons throughout the field. These data contain the cumulative surface gas and water yields for the years of the time-lapse survey, 2011, 2012, and 2013. Well location and top and bottom of horizon depth being produced were also given.

In order to understand the production data trend, it is important to calculate average statistics of the production history. Figure 3.9 shows the average production of water and gas for each of the survey years. Both water and gas production are increasing with time,
Figure 3.9: Average production of water and gas for each survey year

however, the water production increase is greater than that of gas. It is important to note that these values correspond to surface production volumes and not reservoir volumes.

Liu et al. present a water percentage distribution of the major gas-producing layer in the Sebei gas field. This data pertain to the time-lapse gravity acquisition in the field. Figure 3.10 shows the water saturation of the major gas-producing layer, the tectonic contour and the superimposed water-producing wells represented by the blue dots. The size of the dots is proportional to water yield. Figure 3.10 shows there is a positive correlation between water yield of water-producing wells and cumulative water percentage of gas-producing layers. The water percentage is relatively high in the border zone of the gas reservoir which also presents a high water yield of 5-8 tons/day. The high water yield and water percentage in the surroundings of the reservoir indicate an edge water distribution.

With a proven correlation, I assume that water yield data can infer information of the water distribution in the reservoir. Therefore, water production change can infer information of the flow of water drive. An increase in water production indicate an increase of water influx in the field. In pursuance of identifying which wells had increase water production,
I plotted the water production difference between two years for each well using minimum curvature interpolation. The lateral distribution of cumulative change in water yield for all three epochs is plotted in Figure 3.11.

In the 2013-2011 epoch, the plot has two regions of interest. First, the slight increase in water yield in the middle of the field, second are the large changes observed to the west and southwest. The latter is consistent with a southwest to northeast water drive originating from the water circulation system in the deepest level of the reservoir that is recharged by the glacier melt from the mountains located to the southwest of the reservoir. It is important to note that gas-producing wells in the center of the reservoir also show water production increase. Water from these wells does not correspond with the edge-water activity. Water in the center of the gas reservoir originate from different layers that produce water and gas.

For this reason, it is relevant to analyze the water and gas distribution with depth. This requires calculating the water and gas yield difference in time with depth. Figure 3.12 summarizes the average cumulative change in yields from 2011 to 2013 as a function of reservoir depth. The six bars represent the six principal producing horizons. The data indicate that the most significant change in water production occurs at the base of the...
Figure 3.11: Lateral distribution of water production difference for each epoch. This indicates water increase for each time period.
reservoir (bottom horizon), and gradually decreases upward towards the shallow horizons of the field. The gas production is significant in the second horizon and decreases with depth. An increase in water difference for the lower horizons of the reservoir indicates an increase in water influx from 2011 to 2013. This result is also consistent with the geologic information.

With this analysis, I can conclude that production data is a viable tool to estimate the direction and depth of the water influx in a reservoir. I will use the production data in further extent by estimating the total mass change using the reservoir volumes of water and gas. This will give a direct link between these independent data and the source of the time-lapse gravity anomalies.

### 3.5 Summary

In this chapter I analyzed the data used to monitor the water-gas substitution in the Sebei gas field. The two monitoring data given in the area of the reservoir, are a time-lapse gravity survey throughout three years 2011, 2012, and 2013, and the respective cumulative water and
gas yield of 286 wells during those years. The time-lapse gravity acquisition study introduces a new approach using a relative gravimeter to monitor water around a gas reservoir. This new approach helps the accuracy and precision of the gravity measurements by measuring with a CG-5 in fixed cement piles, repeating station measurements in orthogonal routes, and measuring at base stations along a baseline outside of the reservoir area. This acquisition technique laid a foundation for improving the observation accuracy of the survey and reassure good quality time-lapse gravity data. I presented the resulting gravity difference of the time-lapse gravity survey in the area where results show a growing positive gravity change in the center of the reservoir area where the majority of the wells are located. The second section of this chapter consists of extracting the coherent signal of time-lapse gravity data by removing noise. To accomplish this I used the equivalent source technique, a well established method that can be used to process potential field data. The error estimation result show that for the 2011-2012, 2012-2013, and 2011-2013 there error is 8 $\mu$Gal, 9 $\mu$Gal, and 10 $\mu$Gal respectively. This chapter also included a qualitative analysis of the production data. The plots containing the lateral water production difference for the three epochs showed an increase in water production in the southwest area of the reservoir. An analysis of the water production change with depth, showed that the largest change in water production occurred in the deepest horizon monitored by the production wells. This result is consistent with the hydrodynamic information given by the published literature which concludes that this production data is a viable tool to estimate the direction and depth of the water influx in a reservoir.
CHAPTER 4
QUANTITATIVE INTEGRATION

After analyzing the time-lapse gravity data and production and their value for monitoring water encroachment in the field, I will move forward and present the workflow I developed to integrate production data and geologic information in a 3D generalized time-lapse gravity inversion. In this approach, I choose a 3D generalized density inversion in order to include background information and simultaneously recover the 3D distribution of density change from water flood in the Sebei gas field.

In this chapter, I explain how I employed the production data volumes to calculate the density change in each well and build a time-lapse reference model. This information can guide the time-lapse gravity inversion to produce a density contrast model that is close to the water flood predicted by the production data, while requiring the distribution to fit the observed gravity data. Additionally, I incorporate geologic information by enforcing spatially varying bound constraints in independent layers of the model to fit a given density contrast. To choose appropriate density contrasts, I use a lithology column of the area, permeability depth curves, and other referenced geologic information to identify the depths of the lithologic units and the rock type that would most likely permit more water-gas substitution, and therefore create a higher density contrast signal.

4.1 Inversion Parameters

To invert the time-lapse gravity I use a 3D generalized density inversion developed by Li and Oldenburg in 1998. The inverse problem is solved through Tikhonov regularization by minimizing a model objective function subject to reproducing the time-lapse gravity signal and a lower and upper bounds of density change consistent with the field’s porosity and saturation changes from the water drive. This formulation was mentioned in Chapter 3 and refers to equation 3.3. The complete model objective function is shown in equation 4.1.
For this part of the study, I want to focus on the different elements of the model objective function.

\[
\phi_m(\Delta \rho) = \alpha_s \int_V \left\{ w(z) [\Delta \rho(r) - \Delta \rho_{ref}] \right\}^2 dv + \sum_{i=1,2,3} \alpha_i \int_V \frac{\partial w(z) [\Delta \rho(r) - \Delta \rho_{ref}]}{\partial x_i}^2 dv
\]

\[s.t. \Delta \rho_l \leq \Delta \rho \leq \Delta \rho_u\] (4.1)

where \(x_i\) (i=1,2,3) corresponds to the x, y, and z-coordinate, respectively, and \(\rho_{ref}\) is the reference model. Bounds are imposed through the projected gradient method so that the recovered model lies between imposed lower (\(\Delta \rho_l\)) and upper (\(\Delta \rho_u\)) bounds. The coefficients \(\alpha_s, \alpha_x, \alpha_y, \alpha_z\), correspond to the relative importance of different components (x, y, or z) in the objective function which is dependent of the orientation of the features you would like to recover. The coefficients in this case were set as length scales, or the ratio of the x, y, and z model coefficients over the smallest model. This generally defines the smoothness of the recovered model in each direction, where large length scales result in smoother models.

I use length scales of 650 m in each direction because it exceeds the line-spacing (500m) in this area and it is the measure which the model can resolve.

The \(w(z)\) term is associated to the depth weighting function. This function is generally used to counteract the geometrical decay of the sensitivity with the distance of the observation location. In this study, the depth weighting is normalized so that the maximum value is 1. I did not assign specific values for different cells because all the observation points are at a relative constant observation height.

I will use the objective function 4.1 to incorporate the knowledge of the production data and geologic information. The reference model in the above equation contains the density contrast estimated from production wells, I will explain this in the next section. The reference model is generally included in the first component of the objective function and in all the other components. Weighting functions can be used in each component to define which
areas honor the reference model. In this study, I did not assign a weighting function that constrained the inversion to weight specific areas. The relative importance of the reference model, in this case, is the same in all of the recovered cells.

The model was discretized into 50-m cubes and the first layer starts at 1,800 m in elevation. The total thickness of the model is 1,000 m and the area of extent is 160 km\(^2\). I will use this discretized mesh for all of the models calculated.

### 4.2 Time-lapse Reference Model

The reference model is used as a mean to incorporate the production data into the inversion. To do so, I define the density change through the reservoir for each epoch using the changes in water and gas saturations between an initial and final state. This density change associated with the displacement of gas by water is defined by:

\[
\Delta \rho_{\text{ref}} = \phi((\rho_g S_{gf} + \rho_w S_{wf}) - (\rho_g S_{gi} + \rho_w S_{wi}))
\]  

(4.2)

where \(\phi\) denotes the average porosity, \(S_{wf}\) and \(S_{wi}\) represent the final and initial state of water saturation respectively. \(S_{gf}\) and \(S_{gi}\) indicate the gas saturation in the same final and initial stage. \(\rho_w\) and \(\rho_g\) are the density of water and the density of gas in the reservoir respectively. The fluid densities are considered constant because isobaric conditions are assumed. Other assumptions are that the gas saturation is the complement of the water saturation and that the production indicates the volume in place. The substitution of water over gas creates a positive density change, since there is an interest in identifying where this occurs, I constrain the inversion to calculate only positive density contrast values. I also constrain the inversion to positive values considering that the negative values tend to overshadow the positive value result and therefore produce a loss of amplitudes in the positive density contrast anomalies.

Surface volumes were converted to reservoir volumes by using the natural gas-law [Craft and Hawkins, 1991] in reservoir conditions. Since direct saturation values were not provided, the saturation values were calculated as fractional production values. Table 4.1 shows the values of the different properties I used in the calculation of equation 4.2.
Table 4.1: Values of fluid and reservoir properties from different sources

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Density (kg/m$^3$)</td>
<td>150</td>
</tr>
<tr>
<td>Water Density (kg/m$^3$)</td>
<td>1011</td>
</tr>
<tr>
<td>Surface Temperature (F)</td>
<td>60</td>
</tr>
<tr>
<td>Reservoir Temperature (F)</td>
<td>140</td>
</tr>
<tr>
<td>Surface Pressure (psia)</td>
<td>14.7</td>
</tr>
<tr>
<td>Reservoir Pressure (psia)</td>
<td>1450</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.30</td>
</tr>
</tbody>
</table>

The water and gas density values were taken from [Stenvold et al., 2008b], assuming similar water and natural gas composition and reservoir conditions. The average pressure was calculated using local pressure data from 2011 provided with the production data. The average reservoir temperature was obtained from [Dang et al., 2008] and the standard surface conditions were taken from [Craft and Hawkins, 1991].

I calculate the density contrast value from equation 4.2 for each of the 286 wells, and then perform a 3D interpolation between each value at the well location. I used a natural neighbor interpolation which consists of a weighted average technique based on the Voronoi diagram for both selecting the set of neighbors of the interpolation point and determining the weight of each. The interpolation includes assigning a value of 0 to the outside cells that are not within the well area. The average well separation is 50-70 meters, this distance fits well within the original cell separation of the original model chosen (50-m). The well location with respect to the 3D model space is shown in red in Figure 4.1.
Figure 4.1: Well location with respect to the 3D model space. Wells are shown in red.

The interpolated 3D time-lapse reference model is shown in Figure 4.2, the wells are shown in light grey. Of significant relevance is the large change in density in the southern region of the reservoir. In Figure 4.2(b), the model shows the high density contrast coming from the wells in the center of the area. This is consistent with the change in water yield data in Figure 3.11, and the mentioned natural water drive from the southwest. Figure 4.2(c) shows a high density contrast in center of the model which corresponds to the density contrast seen in the time-lapse gravity epoch 2011-2013 (Figure 3.2(c)). The distribution of density contrast in the model and its correlation with previous data allows for a stronger conviction in using the model as a reference for the time-lapse gravity inversion.

4.3 Bound constraints

To integrate the geologic information available in this area, I assign bound constraints to each layer of the reservoir. Digital data are not directly available, therefore to estimate meaningful density contrasts and determine their given depth, I utilize parameters representative of the field obtained from published literature. I first identified the depth of the
(a) Constructed time-lapse reference model 2013-2011 with 0.001 g/cc cut-off at 1,700 m

(b) Constructed time-lapse reference model 2013-2011 with 0.001 g/cc cut-off at 1,400 m

(c) Constructed time-lapse reference model 2013-2011 with 0.001 g/cc cut-off. Profile at 3,530 m northing.

Figure 4.2: Time-lapse reference model shown in different perspectives. The cut-off is 0.001 g/cc.
lithologic units using Figure 2.4. Secondly, I chose different upper bounds of density contrast for those lithologic units with a qualitative analysis of Figure 2.5, and Figure 2.6. A total of 7 horizons were used based on well information, 3 mudstone non-producing layers and the remaining 4 are gas-bearing sandstone layers. These 4 layers have different upper bound constraints because they are located at different depths. Figure 4.3 shows the resulting model of the upper constraints for each layer, the lower bounds were all set to 0. The model has the same extent of the reference model.

![Figure 4.3: Resulting model of the upper constraints for each layer. The higher values that range from 0.3 g/cc to 0.25 g/cc were chosen to represent the producing layers with high permeability and porosity. The intermediate value is set to 0.1 g/cc, these correspond to layers who are producing gas but have a lower permeability value. The top layer was assigned with 0.02 g/cc due to prior knowledge of the area outside of the reservoir seen in Figure 2.4.](image)

By implementing these upper bounds, I can constrain the inversion with depth by permitting more density change in the permeable layers and limiting the density change in the zones we assume are sealing. This serves as a way of imposing geologic structural information of the area. The higher values that range from 0.3 g/cc to 0.25 g/cc were chosen for the producing layers with high permeability and porosity. The intermediate value is set to 0.1 g/cc, these correspond to layers who are producing gas but have a lower permeability value.
For the impermeable mudstone layers I assumed a lower value of 0.02 g/cc. The top layer was assigned with 0.02 g/cc due to prior knowledge of the shallow layer of the reservoir seen in Figure 2.4.

4.4 Inversion Results

To understand the added value of integrating the production data with time-lapse gravity for monitoring water encroachment, I first invert the gravity data with constant bound constraints (0-0.3g/cc) assuming a total water-gas substitution with a 30% porosity. I then compare the result with the gravity data inverted with the spatially varying upper bound constraints and reference model explained previously. The results of the entire model are presented in Figure 4.4. All inversions reproduce the denoised time-lapse data to the expected data misfit defined by the estimated error standard deviation. The grey points in the model represent the -0.5 mGal contour of the residual gravity anomaly seen in chapter3 in Figure 3.1. This helps visualize where the border of the gas reservoir is located.

In all of the models shown in Figure 4.4, the shape of the recovered density anomalies are generally consistent with that of the time-lapse gravity anomalies. The highest density contrast is located on the inside border of the -0.5 mGal contour of the residual gravity which represents the border of the gas reservoir anomaly. It is positioned in the southwestern part of the outline of the gas reservoir and it has continuity towards the NW-SE direction. This feature may correspond to the edge water encroaching into the southwestern part of the reservoir and producing a density change. Although all inversion models recover this feature, the greater difference is seen in the amplitude of the density contrast recovered in this area.
Figure 4.4: Inversion results of time-lapse gravity data over Sebei Gas field. All results are shown in the same color scale. The gray dots correspond to the -0.5 mGal contour of the residual gravity field representing an outline of the gravity low where the border of the gas reservoir is located. (a) Using constant bound constraint (0-0.3 g/cc). (b) Using the reference model calculated from production data. (c) Using different bound constraints dependent on lithology (d) Using the spatially varying bound constraints and reference model.
Figure 4.4(a) shows the inversion with constant bound constraints of 0-0.3 g/cc. This result shows the time-lapse gravity inversion without the integration of additional information. The model shows a large density contrast feature with a peak density contrast of 0.05 g/cc recovered to the southwest of the well locations. Without taking this common feature into account which is present in all the recovered models, the peak density change in a few features in the center of the model ranges from 0.01 to 0.025 g/cc. The amplitudes of the recovered densities are much smaller than that expected for the water encroachment during gas production (0.08 g/cc - 0.150 g/cc).

In Figure 4.4(b) the reference model is used to constraint the time-lapse gravity to the production data. The large density contrast feature seen in the Figure 4.4(a) is also recovered in this model. However, the peak density in the other anomalies, seen in color of red and yellow, range from 0.025 to 0.041 g/cc. This indicates that the density contrast values from these inversions are of higher amplitude than the density contrast values recovered in model Figure 4.4(a). The anomalies with high density contrast are all located in the interior of the gas reservoir. The reference model does not influence the values outside of the well area because the extrapolated values are 0 g/cc. There are no available well data outside the reservoir boundary, therefore it is not reliable to extrapolate random values to the extent of the model. This topic will be addressed in the recommendations for future work.

Figure 4.4(c) and Figure 4.4(d) have a similar shape and density contrast values. The top layers of both models show an average density contrast of 0.0167 g/cc. A uniform density contrast for an entire layer is expected when using layer specific bound constraints. It is important to note that the results of using the spatially varying bound constraints with and without the reference model are very much alike. This may indicate that using a reference model with the spatially varying bound constraints may not contribute to the final model.

This result can be summarized in the form of histograms for the density contrasts recovered in each model. Figure 4.5 shows histograms for every inversion model with a cut-off value of 0.001 g/cc adjacent to the cut-off of the models in Figure 4.4. The histograms show
confirm previous observations: the inversion result of incorporating the reference model shows a higher frequency of larger density contrast values than the inversion results without incorporating the reference model. The histogram of the inversion result with constant bound constraints show a higher frequency of low density contrast values.

To get a better perspective of the anomalies in the middle of the gas field, I captured a profile of each model in Figure 4.4 that is parallel to a line at 5550 m northing. Figure 4.6 shows the summary of each of the profiles of every model with the same colorbar. This figure illustrates the shape of the anomalies recovered with every inversion with more detail. The top image shows the inversion result when using only the time-lapse gravity data and constant bound constraints (0-0.3 g/cc), and the second profile shows the inversion result when using the production data driven reference model. As shown previously, the second image displays higher density contrast values than the anomalies in the first image that were recovered by only using the time-lapse gravity data. The lower third and fourth image shows the inversion result by incorporating the lithology-driven bound constraints and then adding the reference model sequentially. These two profiles show similar shapes and values of density contrast. However, the lower fourth result, which includes the time-lapse reference model and spatially varying bound constraints, shows higher density contrasts recovered in the eastern part of the model. Also, the shape of the largest recovered anomaly is different in the lower image. The distinction between these two images show that the reference model is contributing to the final inversion results. This analysis concludes that by incorporating a reference model and lithology dependent bound constraints, the amplitude of the recovered density contrasts are higher and more consistent with the values predicted by the production data than using the time-lapse gravity data alone. The shapes of the recovered density anomalies are more compact and show a more uniform density contrast. It is clear that an integration of the production data and imposing spatially varying bound constraints into the inversion has significantly altered the inversion results.
Figure 4.5: Histograms of density contrast values recovered from inversion models. (upper-left) using constant bound constraints (0-0.3 g/cc). (upper-right) Using spatially varying bound constraints dependent on lithology. (lower-left) Using the reference model calculated from production data. (lower-right) Using the spatially varying bound constraints and reference model.
Figure 4.6: Profile parallel to 5550 m northing of each inversion result with the same colorbar. (top-first) using constant bound constraints (0-0.3 g/cc). (second) Using time-lapse reference model calculated from production data. (third) Using spatially varying bound constraints dependent on lithology. (fourth) Using spatially varying bound constraints and time-lapse reference model.

4.5 Porosity Estimation

As a simple verification of the inversion results, I convert each recovered time-lapse density into an estimate of porosity distribution in the reservoir. Using equation 4.2, I solve for porosity using the different recovered density contrasts results for each inversion. This can be seen as a computational loop: I first use an average porosity in equation 4.2 to build the reference model which I use for the inversion, I then use the density contrast recovered from the inversion to calculate the average porosity. Because of this loop, I will use different porosity averages for the starting calculation and compare results. In the current section, I
will only present the results when using the given average porosity of the reservoir 30%.

The inversion models calculated previously contain a density contrast in every model cell. In order to solve for porosity at every cell, I must calculate a water and gas saturation value for each model cell correspondingly. To accomplish this, I interpolate the saturation values in each well with the same algorithm used for the reference model interpolation. Figure 4.7 shows the water and gas saturation models for two time periods, 2011 and 2013.

![Figure 4.7: 3D Saturation models calculated with reservoir volumes. All models cut-off is 0.01. (a) Gas saturation 2011. (b) Gas saturation 2012. (c) Water saturation 2011. (d) Water saturation 2013.](image)

Once I obtain a saturation value and density contrast value recovered from the inversion results for every model cell, I solve for a porosity value in every corresponding cell. Figure 4.8 and Figure 4.9 illustrates the porosity values at 625 m and 775 m in depth calculated for every inversion result respectively. The shallow layer case is shown in Figure 4.8, here, the upper left image corresponds to the porosity values calculated from the inversion results using constant bounds. Results show porosity values with higher values than the other three cases. The porosity values calculated using the density contrast recovered from the inversion integrating the spatially varying bound constraints and the reference model shown in the
other three images are lower due to the imposed bound constraints. At this specified depth of 625 m, the upper bound constraints are set to 0.025 g/cc, making the inversion model consider this layer a mudstone. Consequently, this layer is expected to have low porosity values.

Figure 4.9 shows the porosity distribution calculated from the four inversion result for a deeper layer. The porosity values at this layer are lower because the density contrast values at this depth are of low amplitude, also, porosity is known to decrease with depth because of compaction. At this depth, the imposed upper bound constraints are set to 0.20 g/cc. An important feature to note in the lower left image of Figure 4.9 are the porosity values in the middle of the area that range from 0.20 to 0.30. This distribution appears only when using the inversion result that integrates the reference model. This indicates that the time-lapse reference model calculated from production data influences the estimation of porosity distribution and calculates a more realistic value of porosity in the middle of the model. To visualize the porosity estimate with depth, I calculate the average porosity estimated by two specific models at every depth. The first model represents the porosity estimation using the inversion results when using time-lapse gravity data alone. The second model represents the porosity estimates using the inversion results when integrating a reference model and bound constraints which depend on lithology. Figure 4.10 shows the result of calculating the average porosity at depth for the two models. The blue points represent the porosity estimates calculated using the inversion results of the first model (only using time-lapse gravity data). The red positives represent the porosity estimates calculated using the inversion results of the latter model (using the spatially varying bound constraints and reference model). Results show that at shallow depth the porosity estimates differ significantly. The integrated model (red positives) estimates lower porosity in the shallow layers due to the bound constraints that were imposed as mudstone in the first layer. At deeper values there is a deviation; the porosity values are higher in the integrated model estimate for the deeper reservoir layers. This result shows that the integrated model is able to estimate porosity values that are closer
to the depicted value of the entire reservoir at higher depths. Although the values of porosity do not match the results presented in [Dang et al., 2008] (Figure 2.6), the general trend of the curve is consistent with the lithologic model used in the inversion algorithm.

In the porosity models presented, the values of 0.90 porosity are unrealistic in this field and the distribution of porosity is highly controlled by the depth of the density contrast values derived. On account of simplicity, an average value of porosity for every model will be more convenient for a verification process. Table 4.2 shows the average porosity values calculated using the density contrast values of various inversion results. Each value of average porosity was calculated using the entire porosity model. The porosity estimate for the inversion using a time-lapse reference model and lithology dependent bound constraints is closer to the rough average of the field according to references 30% [He et al., 2015]. It is important to note that the calculated average may be lower due to the imposed upper bound constraint that are lithology dependent. These assume that 55% of the reservoir is mudstone and the remaining 45% is sandstone or silty sandstone. Assuming the average porosity of the mudstone is 20% [Dang et al., 2008] and that the aranecous rock is 30% then the total average porosity depending on the imposed lithology model is 24%.
Figure 4.8: Porosity values at 625 meters of depth. (Upper-left) Using constant bound constraints (0-0.3 g/cc). (Upper-right) Using spatially varying bound constraints dependent on lithology. (Lower-left) Using the reference model calculated from production data. (Lower-right) Using the spatially varying bound constraints and reference model. The porosity values calculated using the different bound constraints and the reference model are lower due to the imposed bound constraints.
Figure 4.9: Porosity values at 775 meters of depth. (upper-left) using constant bound constraints (0-0.3 g/cc). (upper-right) Using spatially varying bound constraints dependent on lithology. (lower-left) Using the reference model calculated from production data. (lower-right) Using the spatially varying bound constraints and reference model. An important feature to note in the lower left image of Figure 4.9 are the porosity values in the middle of the area that range from 0.20 to 0.30. This distribution appears only when using the inversion result that integrates the reference model. This indicates that the time-lapse reference model calculated from production data has an impact on the estimation of porosity distribution.
Figure 4.10: Average porosity values with depth. The blue points represent the porosity estimates calculated using the inversion results of the first model (only using time-lapse gravity data). The red positives represent the porosity estimates calculated using the inversion results of the latter model (using the spatially varying bound constraints and reference model). Results show that at shallow depth the estimates differ significantly. The improved model (red positives) estimates lower porosity in the shallow layers due to the bound constraints that were imposed as mudstone in the first layer. The porosity values are higher for the deeper reservoir layers. This result is consistent with the lithologic model used in the inversion algorithm.
Table 4.2: Average porosity values calculated using the density contrast values of various inversion results. The elements used in the inversion are indicated for every result.

<table>
<thead>
<tr>
<th>Inversion procedure</th>
<th>Porosity estimate (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant bound constraints and no reference model</td>
<td>10</td>
</tr>
<tr>
<td>Bound constraints dependent on lithology and no reference model</td>
<td>12</td>
</tr>
<tr>
<td>Time-lapse reference model calculated from production data</td>
<td>9</td>
</tr>
<tr>
<td>Time-lapse reference model and lithology dependent bound constraints</td>
<td>13</td>
</tr>
</tbody>
</table>

These porosity estimates function as a first-order analysis of the various inversion results using different elements. Although this is a rough estimation and can be ambiguous, it also serves as a simple method to estimate static reservoir parameters using a time-lapse gravity data. By integrating a time-lapse reference model derived from production data and imposing bound constraints that resemble the lithology into the inversion, I proved that the porosity estimates calculated using this process are more representative of the known porosity of the gas reservoir.

4.6 Summary

In this chapter, I first presented the workflow I developed to integrate production data and geologic information in a 3D generalized time-lapse gravity inversion and simultaneously recover the 3D distribution of density change from water flood in the Sebei gas field. I described how I used the production data volumes to calculate the density change in each well and built a time-lapse reference model. This information was used to guide the time-lapse gravity inversion to produce a density contrast model that is close to the water flood predicted by the production data, while requiring the distribution to fit the observed gravity data. Additionally, I incorporated geologic structure information by enforcing bound constraints that vary with depth depending on the lithology. The upper bounds set to allow higher
density contrast correspond to the sandstone while the bounds set to constrain the result to a lower density contrast correspond to the mudstone. Results show that by incorporating a reference model and lithology dependent bound constraints, the amplitude of the recovered density contrasts are higher and more consistent with the values predicted by the production data than using the time-lapse gravity data alone. Also, the shapes of the recovered density contrast anomalies are more compact and show a more uniform density contrast which allows for an improved interpretation of the model. As a simple verification of the inversion results, I converted each recovered time-lapse density contrast into an estimate of porosity distribution in the reservoir. By integrating a time-lapse reference model derived from production data and imposing bound constraints that resemble the lithology into the inversion, I proved that the porosity estimates calculated using this workflow are more representative of the known porosity of the gas reservoir than using gravity data alone.
I performed a study of a gas reservoir by analyzing a time-lapse gravity data set and integrating production data in the Sebei Gas field located in Western China in order to monitor the edge-water movement. This was done with the objective to characterize the reservoir and detect areas of high density contrasts where the increase in water saturations could affect the gas production. Time-lapse gravity reservoir monitoring is proven to be useful technique when monitoring water movement in a gas reservoir, which applies to this study. Although time-lapse gravity may have sufficient resolution in shallow reservoirs, it is always beneficial to integrate different data types to complement the time-lapse gravity interpretation. When monitoring the water-influx in a reservoir, an increase in water yield in some wells of the area may indicate increasing water saturation values in its surrounding. Therefore, production data can also suggest areas of fluid movement and density contrast change with time. These data can complement the time-lapse gravity analysis, and the question to address is how to integrate these two data set appropriately in order to benefit the monitoring of the edge-water in the reservoir.

Time-lapse gravity data were acquired every year from 2011 to 2013 at this site. I have processed this data set by using the equivalent source technique to estimate the error level. Subsequently, I evaluated and plotted the production data to determine its feasibility as complementary data for the time-lapse gravity inversion. To constrain the inversion result to a similar lithologic setting of the reservoir, I included upper and lower density contrasts bounds at different depths of the reservoir model.

In this work I presented the results of various time-lapse gravity inversions integrating production data and spatially varying bound constraints. With this study I developed a workflow to determine which result was more representative of the known parameters of the
reservoir. It is concluded that time-lapse gravity and production data are complementary tools when monitoring water-encroachment in a gas reservoir. However, it is important to also include the upper and lower bound constraints that represent the known lithology of the reservoir setting. Following are the main conclusions that can be drawn from this study:

1. One important conclusion is that time-lapse gravity data, a geologic structure model and production data can be integrated using a gravity inversion algorithm. When constraining the inversion to these data, the anomalies in the result show an increase in the density contrast amplitude which are closer to the expected values of the density contrast generated by water-gas substitution. Also, the shapes of the recovered density contrast anomalies are more compact and show a more uniform density contrast which allows for an improved interpretation of the model.

2. A first order porosity estimate can be calculated from all time-lapse gravity inversion results. The average porosity estimated using the density contrast from the inversion result with time-lapse gravity data alone is 10%, while the average porosity estimated using the density contrast from the inversion that included the production data and spatially varying bound constraints is 13%. This result is lower than the average value estimated in the published literature due to the imposed upper bound constraints. These constraints assume that 55% of the model is composed of mudstone, therefore the inversion results calculate a lower porosity average for the entire model. The estimation of reservoir porosity from the inverted time-lapse density models demonstrates that the density contrast values recovered from the inversion with production yields and spatially varying bound constraints are more representative of the known porosity of the gas reservoir.

3. By integrating the time-lapse reference model into the inversion, the amplitude of the density contrast in the gas reservoir area is increased and the recovered features are more pronounced. This is especially true for the large feature seen on the edge of
the gas reservoir contour. The increased amplitude is closer to the expected density contrast caused by water-gas substitution in the reservoir. The higher amplitudes of density contrast provide new information of the water-gas replacement occurring outside the reservoir. These features assist the interpretation in identifying new zones of water movement through the reservoir.

4. The time-lapse reference model derived from the gas-water production yield complements the inversion in the middle of the field where the wells are located. However, the production data does not help extract new information on the outside region of the wells. Well information is known to be indicative of reservoir conditions but it is limited to a certain radius of influence. In this study, the wells have a separation of 30m-40m, this distance is tolerable for interpolating the data at each well when using a cell spacing of 50m. Extra caution should be taken when interpolating well data that are located at greater distances.

5. The inversion results show a prominent density contrast feature recovered in the southwest border of the gas reservoir. This feature can be associated to the edge-water coming from the hydrodynamic system stated in the geologic references. Although the hydrodynamic system is coming from the Kulun mountains located to the southwest of the reservoir, there are no significant density contrast features recovered outside the reservoir boundary. This implies that the major density contrast is occurring on the reservoir boundary near the wells due to various wells that are located on the border of the reservoir, these are dragging large amounts of water and increasing the rate of water influx causing a high density contrast. Another interpretation of the features of the inversion model could be another source of water influx. The inversion models recover high amplitude density contrast feature coming from the the southeastern part of the survey area, indicating the possibility of an additional water influx system coming a source located to the southeast of the reservoir area.
5.1 Recommendations For Future Work

1. Quantify the uncertainty of the time-lapse gravity inversion.

   - The idea consists of using additional data in a geostatistical analysis to find areas of uncertainty in the inversion result. Also, calculating more accurate constraints can help decrease the level of uncertainty in the final result. Due to time constraints, this analysis was not included in this thesis work. Both the reference model and spatially varying bounds constraints used in this study have a high level of uncertainty due to the lack of available information. Seismic horizons and detailed well logs could be used to better determine the depths of the lithologies and help reduce uncertainty. Seismic horizons could provide accurate depths of contrasting lithologies. By analyzing well-logs, the upper and lower bounds model could have a tighter range of values which are more credible and would result in a more accurate porosity estimation. To reduce the level of uncertainty in the reference model, a more accurate interpolation method can be used. Methods such as sequential gaussian simulations can generate various reference models and therefore use statistical approaches to evaluate a final result. Also, the water saturation calculation can be highly ambiguous. One tool commonly used for accurate water saturation estimation are well resistivity logs. By estimating precise saturation in each well, the density contrast values would be more accurate and result in a better reference model construction. A more detailed inversion of the reference modeling errors should follow to investigate the limitations of the proposed approach.

2. Understanding the pressure change of the field over time.

   - The reservoir pressure distribution can help diagnose a water driven aquifer. This was proven by [Glegola et al., 2012] in their work on integrating gravity data and pressure data in a reservoir. They showed that joint assimilation of pressure
and gravity data can provide more-constrained inverse solutions and result not only in improved gas and water production forecast, but also give more accurate reservoir-state description. For peripheral-water and edge-water drives, higher pressures tend to exist along the reservoir/aquifer boundary while lower pressures tend to exist at locations that are more distant. Pressure measurements taken at each time of the gravity survey would be very useful to identify zones of pressure depletion and increase to identify zones of possible edge-water drive.
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