Simulating the Impact of Methane Gas Production from the Clearwater B Formation on the Regional Groundwater Flow System

by

Fanlong Meng

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AUTHOR'S DECLARATION

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Fanlong Meng

Abstract

The production of natural gas from a saline aquifer will reduce the pressure regime in that aquifer to some degree. Simultaneously, this relief in pressure will causes gas to be exsolved out of the aqueous phase, which will partially mitigate this reduction in pressure. In terms of groundwater resources, the net effect of these two processes results in a reduction of pore water pressure within the aquifer, the surrounding groundwater system, and potentially the surface water system. Previous work has shown that results generated by the single-phase groundwater models used in Alberta's oil sands typically over-predict aquifer hydraulic heads in regions where gas production activities are intensive. Over-prediction is an issue because the results from single-phase models are used by industry to manage makeup water supplies for generating the steam needed to extract bitumen in the in-situ region of the oil sands. Industry operators need to understand how much makeup water is available so that steam production does not become a bottleneck to production and to remain compliant with regulations that place limits on how much available head is extracted from a given aquifer. The source of this over-prediction is assumed to be due to the current inability of single-phase models to adequately capture the inherently multi-phase interactions between gas production and pore water pressure within the aquifer. Historical precedence and regulatory expectations likely mean that the use of single-phase models will continue. The question then becomes whether it possible to modify how single-phase models are applied to this type of work so that these multi-phase interactions are better captured, resulting in more representative makeup water level predictions. The current study makes the initial steps towards answering this question.

This study applies multi-phase and single-phase simulators (CompFlow Bio and HydroGeoSphere, respectively) to develop a better understanding regarding how historical gas production has influenced pore water pressures in the saline Clearwater B aquifer used by Nexen within its Leismer lease (Athabasca oil sands region, Alberta, Canada). Nexen uses the Clearwater B aquifer for makeup water in its in-situ operations. Geological and conceptual models are developed and used for setting up CompFlow Bio and HydroGeoSphere numerical models. The information needed to parameterize both models is discussed along with the simulation results from their application to this site. Study findings indicate that CompFlow Bio is able to provide physically correct results, which are consistent with Clearwater B field observations. While CompFlow Bio predicts that makeup water extraction from the Clearwater B results in significant drawdowns in available head within that aquifer and the overlying units, there appears to be no obvious impact on the surface water system. Conversely, application of HydroGeoSphere highlights the limitations of using single-phase models in predicting available head in gas-production-impacted aquifers. Recommendations are provided regarding how single-phase models might be better adapted to address these limitations, for example, dynamically adjusting specific storage and hydraulic conductivity values on a time-step basis.

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Many hydrogeologist and geologists in industry have assisted me over the course of my study. I thank Andrea Walter, John Horgan, Cathy Main and Danika Muir, the hydrogeologists in Nexen, to provide me provided me an opportunity to join their team as intern, and who gave great support on software, data and literature sources. Without they precious support it would not be possible to conduct this research.; I thank Lisa Pacholko, Lori Skulski and Maureen Hill, geologists in Nexen, to give me guidance and tutorial on geological background and mapping skills and review on my geological model; I also thanks to Rudy Maji, hydrogeologist in Golder Associates, to give me professional advice on dissolved gas topic.

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Chapter 1

Introduction

Groundwater is an important resource for oil sands stakeholders to generate steam for operations. The Clearwater B aquifer underlying much of the oil sands region in Alberta is a typical saline aquifer. Such aquifers are usually considered unsuitable as drinking water resources. However, saline aquifers are ideal sources of make-up water for local oil sands operators. The Clearwater B aquifer also contains considerable natural gas trapped below the overlying aquitard. The main pool is estimated to contain $3{,}327 \times 10^{9}$ m^{3} gas, mainly composed of pure methane (Statoil, 2012). As aqueous phase and gas phase co-exist inside one system, the pressures of both phases will be disturbed when one phase is withdrawn. In general, a sustainable groundwater extraction rate would not be expected to generate appreciable impacts on the entire groundwater system. However, when this sustainable groundwater extraction is coupled with simultaneous methane production, the potential exists to create significantly lower pore water pressures within the entire groundwater pressure system. In the case of the Clearwater B aquifer, concurrent groundwater and gas production have the potential to depressurize the aquifer, lower the available head in overlying aquifers, and perhaps impact surface water resources.

The study area for this work is Nexen's Leismer Lease, which is located within the in-situ Athabasca oil sands area, approximately 100km south of Fort McMurray, Alberta (Statoil, 2012). The Clearwater B aquifer lies beneath the lease and Nexen would like to use it as a source of makeup water (water used in oil sands extraction to assist separate heavy oil from sediments) for their project. The Clearwater B is primarily composed of unconsolidated porous sandstone, approximately 30 meters thick and has a maximum of 20 m of natural gas trapped on along its top under the study area. The formation is wide and continuous across the Leismer and surrounding leases, and contains several economic gas pools that have been in production since 1978 (starting at well 00/11-30-076-07W4/0) (Statoil, 2012). Currently, Devon Canada is the largest methane gas producer from this formation. Simultaneously, Cenovus is withdrawing saline makeup water from the Clearwater B to generate steam for its Christina Lake SAGD Project (near the southeast portion of the main gas pool). The competition between current operator makeup water extraction activities, regulations dictating sustainable groundwater resource management and gas production lowering the aquifer's pore water pressure has raised uncertainty in terms of the Clearwater B's use as a makeup water source for additional operators. As a consequence, it is essential and imperative for Nexen's water strategy team to understand the how these competing influences are impacting the aquifer's capacity before proceeding with using it in their project. Moreover, it is also necessary to understand, quantify and predict how current and proposed extraction activities could impact the overlying aquifers and surface water system, both for Nexen's planning purposes and to better inform regulatory bodies.

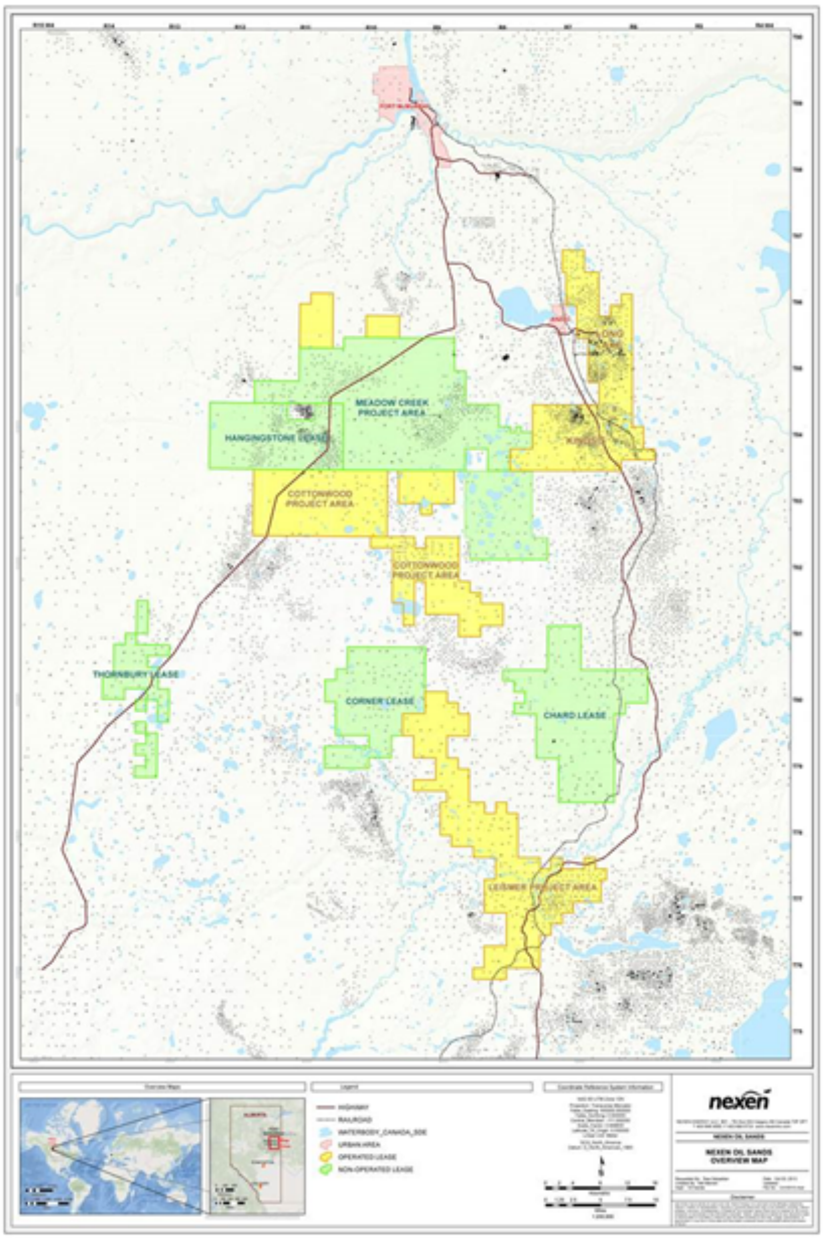

Figure 1 Nexen Oil Sands Land Map. Leismer Lease is located in the south of the map. Leases in yellow are Nexen operated properties, leases in green are non-operated properties (Nexen Inc., 2015).

To support Nexen's efforts, this study will focus on improving our current understanding of how gas extraction activities have influenced pore water pressures in the portion of the Clearwater B aquifer underlying Nexen's Leismer Lease. Three basic questions drive this effort: 1) How is gas trapped in Clearwater B Aquifer?; 2) How does methane gas production impact regional flows?; and 3) Does methane gas production reduce hydraulic head in the aquifer? As well, this study also sought to identify appropriate numerical tools (models) to answer these questions. The single-phase numerical tools traditionally used for groundwater resources investigations in this region are also considered and critiqued.

Available hydrogeological and geological data at the Leismer lease were used to setup the models used and lessons learned from recent regional groundwater modelling studies were incorporated into their application.

The outcomes from this study represent an advancement of our conceptual understanding of gas production impacts on pore water pressures in terms of the three questions posed above. The relative uncertainty of the physical properties needed to parameterize the models are reviewed and appropriate numerical tools are identified.

1.1 Conceptual scope of study

Natural gas production occurring along the top of a targeted aquifer will reduce the pore water pressure. This phenomenon has been observed at numerous operations sites via their respective groundwater monitoring well networks. Contrarily, the simultaneous process of gas exsolution during production will tend to increase pore water pressure (Yager, Miller, & Kappel, 2001). The net effect of these two competing processes is an overall reduction in pore water pressure, resulting in a localized or regional drop in total hydraulic head within the aquifer being stressed.

Figure 2 pictorially describes the research problem considered in this study. Assume a confined sandy aquifer which contains gas cap residing along its upper extent, as well as dissolved gas in the water. When gas is produced from this cap, pressure within the cap and pore water pressure within the rest of the aquifer will decline. The blue dashed line on Figure 2 represents the pre-production potentiometric level and the green dashed line is the reduction in that level in response to gas production. As can be seen in the figure, this reduction in the potentiometric level is reflected both in the gas well screened in the cap in addition to the nearby monitoring well screened in water bearing portion of the aquifer.

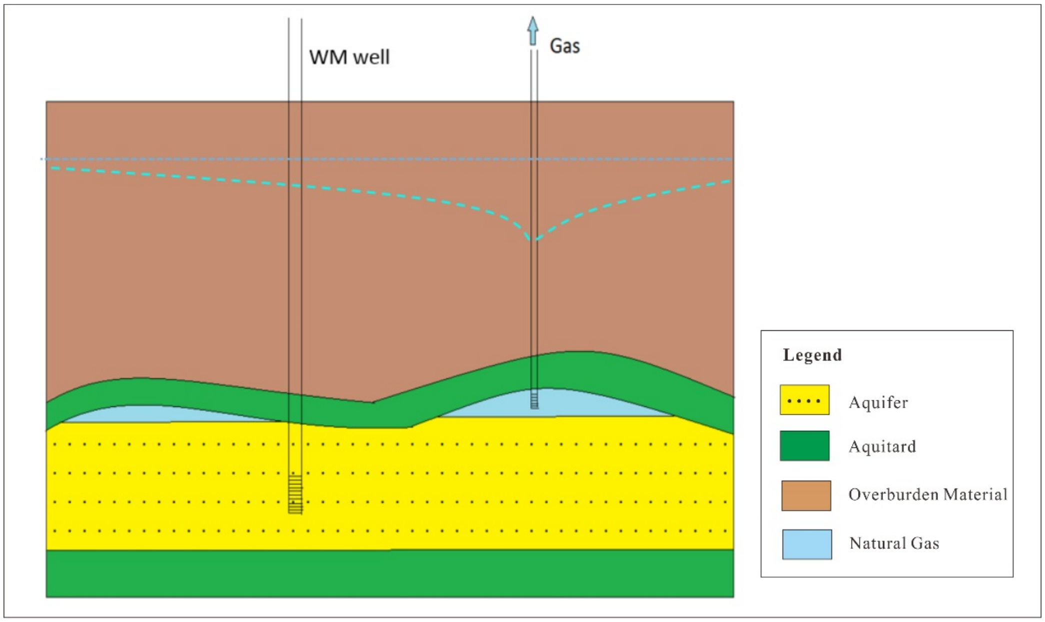

Figure 2 Sketch of study case: predicted hydraulic head drawdown in water monitoring well responding to gas production

A large number of regional groundwater modeling studies have been conducted within the Athabasca oil sands region. The results of these studies are commonly used by industry within the in-situ portion of the oil sands to assess the viability of a given aquifer as a source of make-up water used to generate steam during operations. Alberta's regulatory framework requires from the operator that: 1) their make-up water extraction activities may not significantly impact the groundwater supplies of neighboring operations or other stakeholders (cumulative effects) and 2) cannot use more than 50% of the aquifer's pre-development pressure head at any point over the life of the project. Given the importance of understanding the amount of make-up water that is available for a project (no water = no project), it is important that the model predictions reasonably reflect the targeted aquifer's makeup water potential. If they do, considerable uncertainty is inadvertently introduced into the information used to make groundwater resource management decisions. However, majority of groundwater models, including those are preferred by regulators, simulate the groundwater flow dynamics using a single-phase flow conceptualization. The influence of other phases, such as gas, on the flow of water are not considered in the predictions generated using single-phase groundwater models. This limitation originates from the governing Richards Equation used in many single-phase groundwater models. Richards Equation cannot simulate gas flow either above or below water table. Therefore, single-phase groundwater models are likely to provide inaccurate hydraulic head prediction in the regions where gas production activities are intensive (such as the study region).

The inability of single-phase models to capture the influence that gas production has impact on the water levels within the affected aquifer has been increasingly recognized by industry. The locally irregular depressurization of the affected aquifer's potentiometric surface is simulated as being relatively flat and, as a consequence, any water levels measured within this depressed zone are tagged as anomalous and often excluded during calibration. For example, the simulation results produced by Korea National Oil Corporation (2008) regional groundwater model predicted hydraulic head values in the vicinity of project area of approximately 475 masl (meters above sea level) within the Clearwater B unit of the Clearwater Formation. Gas has been produced from this unit in the vicinity of the project for quite some time. However, actual head values are between 360-380 masl in this region. The inability of the model to capture this depressed potentiometric surface will significantly affect its ability to predict of vertical downward groundwater flow locally. As well, if these model results would have been used as the sole basis for this company's water management decisions (including make-up water planning), they would have assumed there is considerably more drawdown capacity in the targeted aquifer than actually exists.

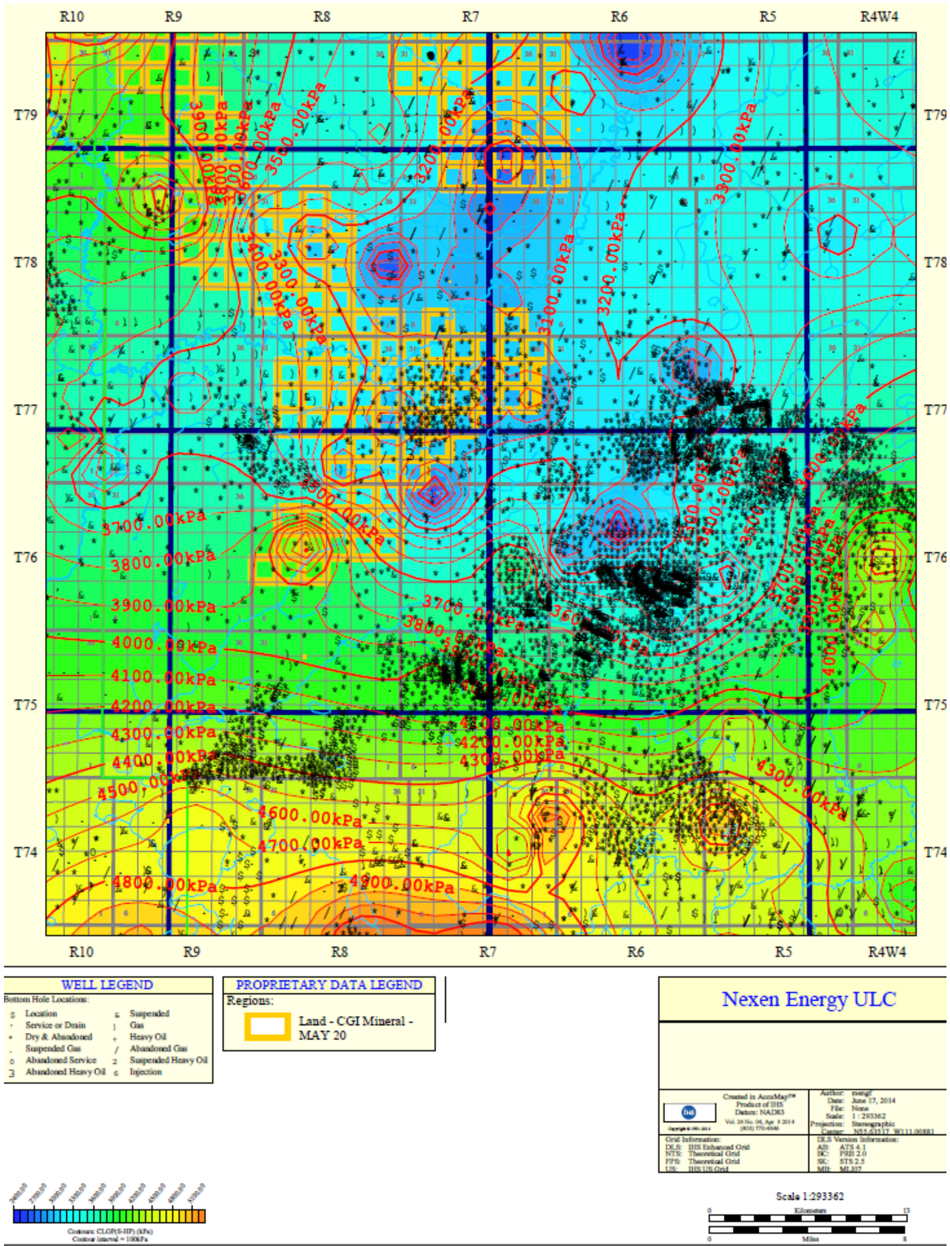

Figure 3 Clearwater Formation hydro-pressure within study area

Barson, Bachu, and Esslinger (2001) point out that gas pools found in Upper McMurray, Clearwater and Grand Rapid formations do not have an impact on regional scale hydrodynamic regime; however, gas production from the pools directly contacting water-saturated aquifer affect the local pressure regime to some degree. A literature search on this topic yielded little information regarding the mechanisms that decrease an aquifer's pressure head in response to gas production; primarily some reservoir engineering studies that considered gas and water relationships during gas pocket production, including water flooding, water conning, bottom and edge water invading, etc. (Ader, Williams, & Hanafy, 1997; Binshan et al., 2008; Chen, Chu, & Sadighi, 1996; Hoyland, Papatzacos, & Skjaeveland, 1989; Yong et al., 2010). To date, little research has been conducted regarding how best to simulate hydraulic head drawdown due to methane gas production. Other areas that need further investigation include: the quantification of reduction in pore water pressure when a given amount of gas if produced from the top of the aquifer; the mathematical relationships; the controlling physical mechanisms; and the most appropriate hydrogeological modeling tool to predict the impacts (i.e., can a single-phase model be modified to this purpose or is a different type of model needed?).

1.2 Study Objectives

As noted in its EIA report, the “dimpled” hydraulic head pattern observed within the Clearwater Formation regional flow patterns due to historical gas production cannot be reproduced by a single-phase regional groundwater model (Harvest Energy, 2010). This simple fact has also been noted in other EIA groundwater modelling studies in the oil sands that targeted the Clearwater B as a source of make-up water for producing steam (Devon Jackfish, 2006; Encana Christina Lake, 2009, among others). The abundance of the gas phase and its extraction from the Clearwater B aquifer generates concern in terms of using it as a make-up water source due to the possible negative effects of reservoir depressuring on gas and water recovery. In addition, the impact of depressurization due to gas production on surface water resources should also be considered and predicted. Figure 3 presents the disturbed hydro-pressure condition of Clearwater Formation under the combined impacts of water and gas production. To better understand the physical mechanism(s) that govern how gas extraction influences pore pressure drawdown, further study is required. As well, there is a need to determine an appropriate modelling tool for Oil Sands operators to more accurately plan for their make-up water requirements when faced with using aquifers from which gas is (or was) being produced.

In this study, steady-state and transient multi-phase simulations will be performed using a hypothetical case which is based in part on measured properties of the Clearwater B aquifer, located in the in-situ region of the Alberta oil sands. This hypothetical case has been designed to be representative of a situation where make-up water is to be removed from the Clearwater B in the presence of production of a gas pocket located along the top of the aquifer. Transient and steady-state single-phase simulations will also be performed using the same hypothetical case. The goal is to determine ways by which the results predicted by the multi-phase simulations can be (roughly) replicated using a single-phase model via modification of those models properties. The methods used in this study were documented and evaluated, and a discussion of findings regarding modeling errors and limitations is presented.

Chapter 2
The Study Site Characterization

The following section briefly summarized the comprehensive review on geological and hydrogeological investigation within study scope. It includes previous mapping and modeling reports, overview of the regional scale stratigraphic framework and groundwater flow system in Athabasca Basin. The information is directly applied to numerical model construction.

2.1 Geological Review

The study area is located in east central of Alberta within Athabasca Basin (Figure 1). Surface elevation is around 600 meters above sea level. Figure 4 graphically summarizes the underlying formation, from the middle Devonian bedrock to overburden materials (Nexen Inc., 2015). Specifically, this study focuses on the siliciaclastic strata separated by angular unconformities from underlying Devonian carbonates. Approximately, there are three major formations bounded by such unconformities: the McMurray, Clearwater and Grand Rapid Formations, which are overlain by the sandstone and marine shale succession of the Lower Cretaceous Mannville Group. The uppermost units are glacial Quaternary sediments (Huang, 2014). In detail, deposition of the McMurray formation is terminated by regional marine transgression of the Boreal Sea within study area continued south to the U.S boarder. Shoreline, estuarine and tidal facies compose the base of Lower Cretaceous sediments including Wabiskaw formation. The Clearwater Formation was subsequently deposited after the subsidence in central Alberta and is characterized by the fine grained marine basin deposit (Jackson, 1984). The massive sandy Clearwater and Grand Rapid Formation are interpreted as the extension of east-west-trending coastlines, which is terminated by regional Joli Fou transgression (Jervey, 2003). Gaseous hydrocarbon is observed in the Clearwater and Grand Rapid Formations, and are accumulated under structural control. It is believed to have been generated through degradation of liquid hydrocarbons by meteoric-water and microbial activity (Bachu, 1995; Masters, 1984; Vigrass, 1968).

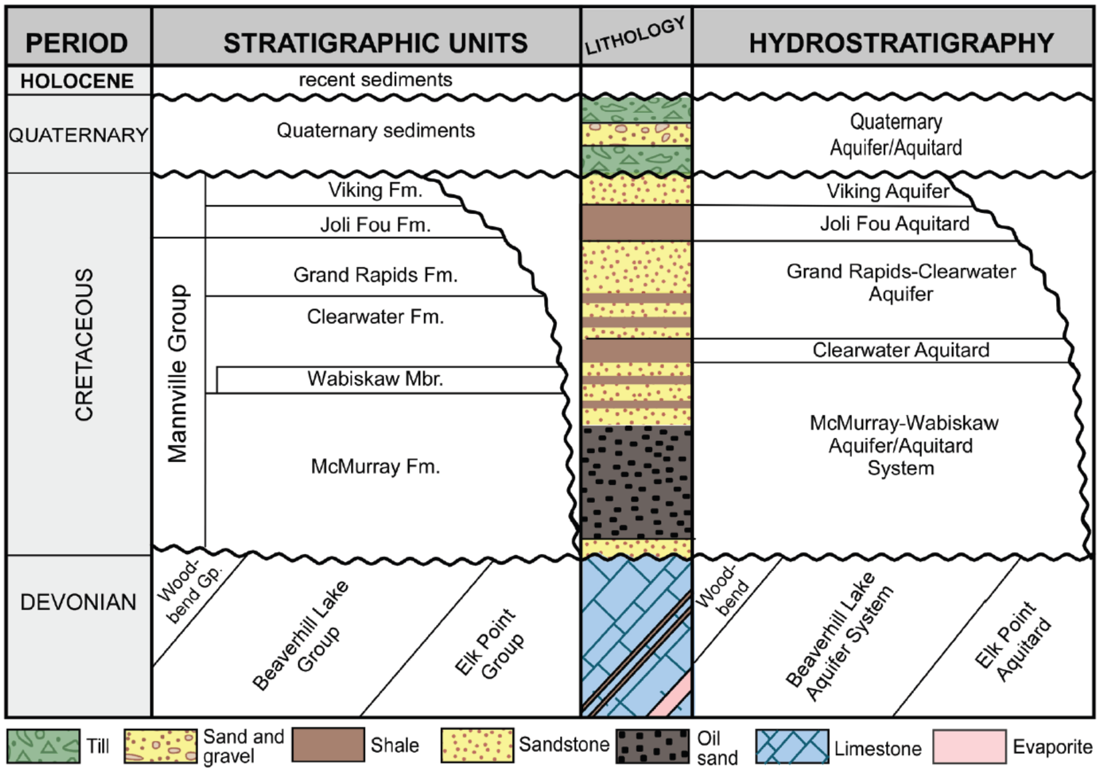

Figure 4 stratigraphic column of Lower Cretaceous within study area (Baron et al. 2001; permission granted from the Bulletin of Canadian Petroleum Geology))

In particular, the Clearwater Formation predominately comprises of three shoreface sand layers trending roughly southeast-northwest or east-west within the study area. These shoreface sand are subdivided into regional units named Clearwater A, B and C (Jervey, 2003). The thick sands of Clearwater B are unconsolidated, moderately to well sorted, fine to medium-grained and show a predominance of upward coarsening gamma log profiles (Figure 5). The crosschecked neutron and density well logs indicate the occurrence of gas in Clearwater B aquifer in the Leismer Lease. The gas distribution map and gas-cap thickness Isopach map are generated based on data summary from well logs (Figure 6). The gas cap thickness shows a range up to 20 meters, with an average 10-meter thickness. By using the Dodson and Standing (1944) method, the Clearwater B main pool is estimated evolving $3{,}327 \times 10^{9}$ m^{3} natual gas (Statoil, 2012). Dissimilar to the Grand Rapid Formation gas pools, there are no fine-grained interlayers laterally isolating the gas pool and main sand.

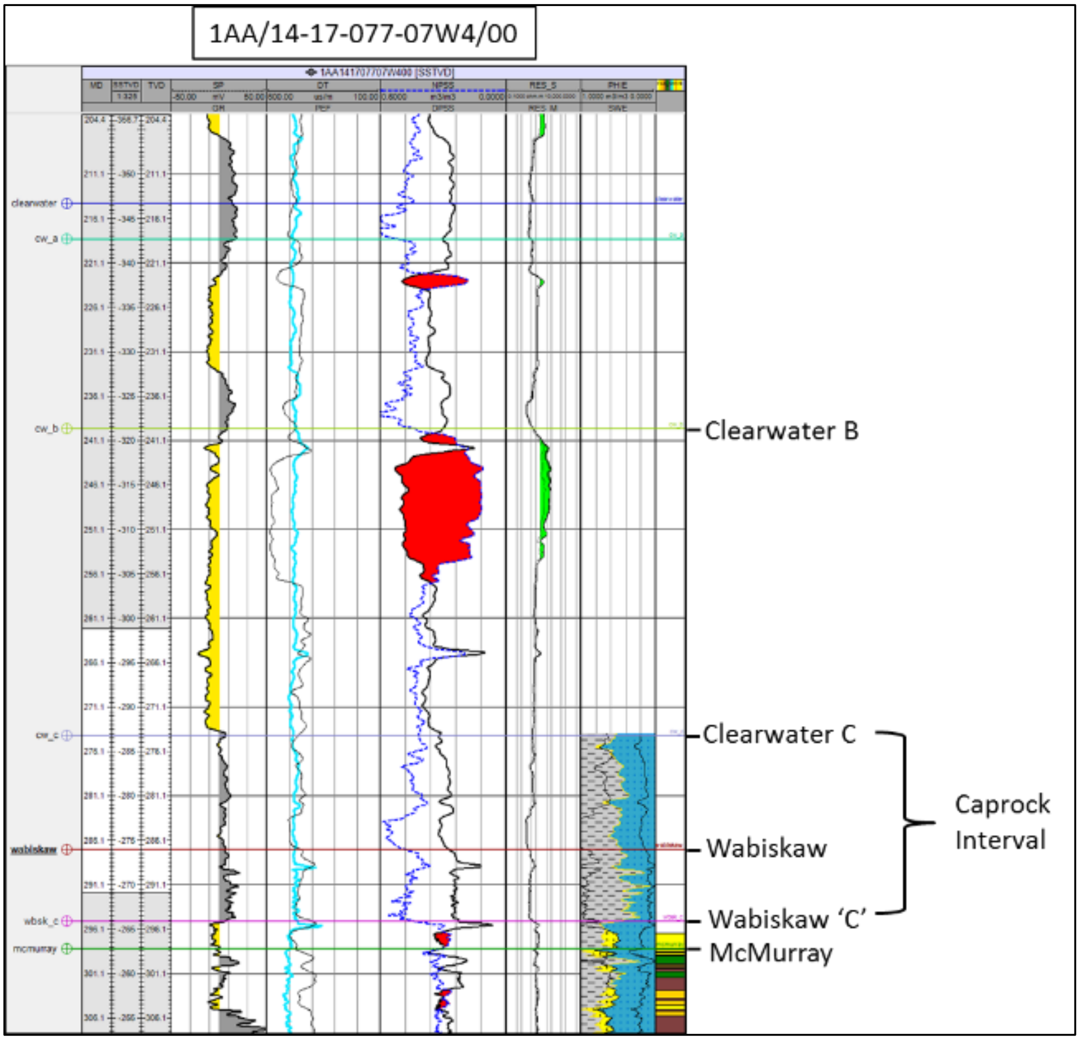

Figure 5 Well logs of 1AA/14-17-077-07W4/0 in Leismer Properties, an example of well log interpretation: the crosschecked neutron and density well logs show the occurrence of gas in Clearwater B in Leismer Lease

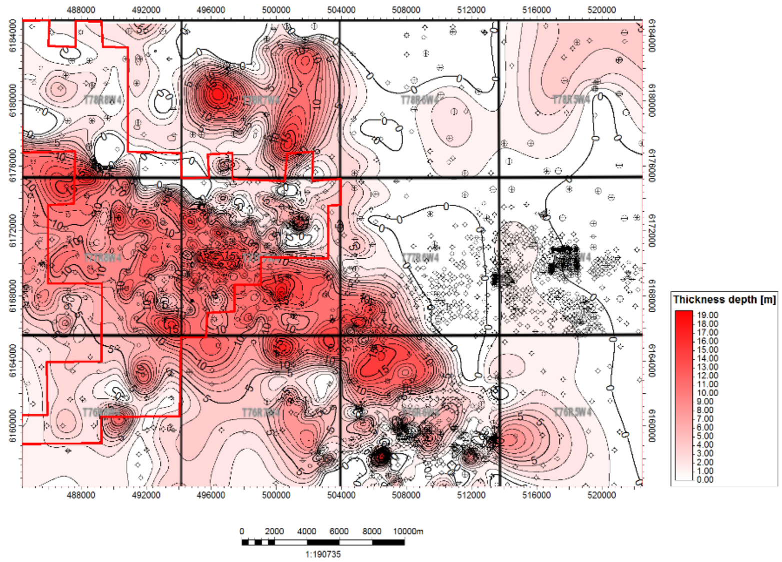

Figure 6 Clearwater B gas cap Isopach map

Geological study is the preliminary work needed to establish an appropriate numerical model. The geological model simplifies geological information and assists to establish and defined the rim of the gas reservoir. Yong et al. (2010) points out a fine geological model can be directly introduced into numerical simulation tools without up-scaling. Extensive well log data from study area have supplemented abundant and comprehensive datasets for strata details. Geophysical logs cross-section (Figure 7) were selected to present the local geological features and used to calibrated and correlated model mesh design. Top-picking of other formations was based on geologists' interpretation stored in database of AccuMap. The geological work containing in this study was evaluated and reviewed by geologists working on Leismer lease in Nexen, to provide confidence in accuracy of geological model. Through comprehensive well logs data interpretation, a simplified geological model is depicted in Figure 9. The stratigraphic information contributes to understand hydrostratigraphic setting and numerical model mesh establishment, especially the formation geometry and the accurate depth of each formation.

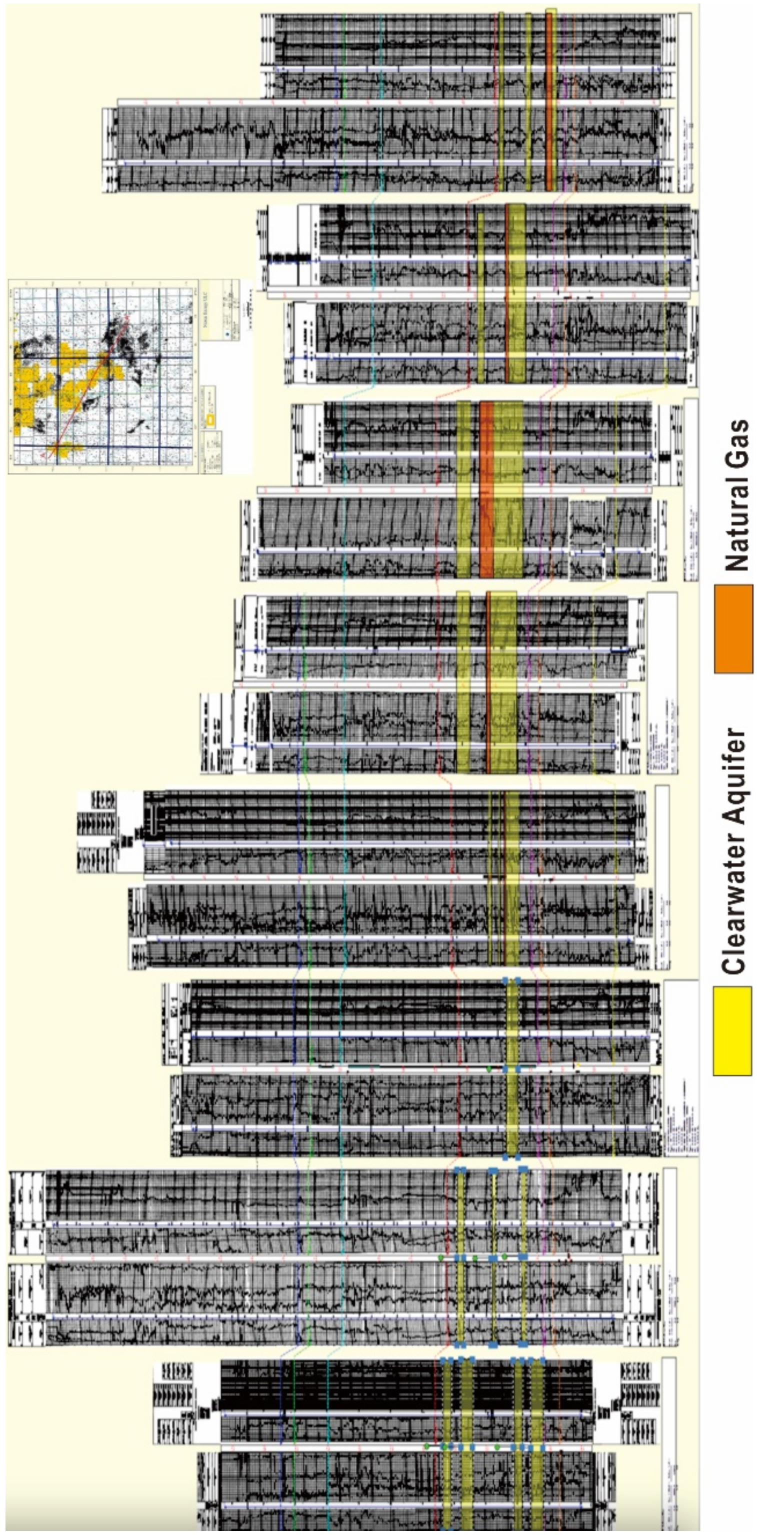

Figure 7 Well Logs interpretation (regional scale): gas cap, Clearwater sandy units and top picking of other formation tracing laterally alone regional section

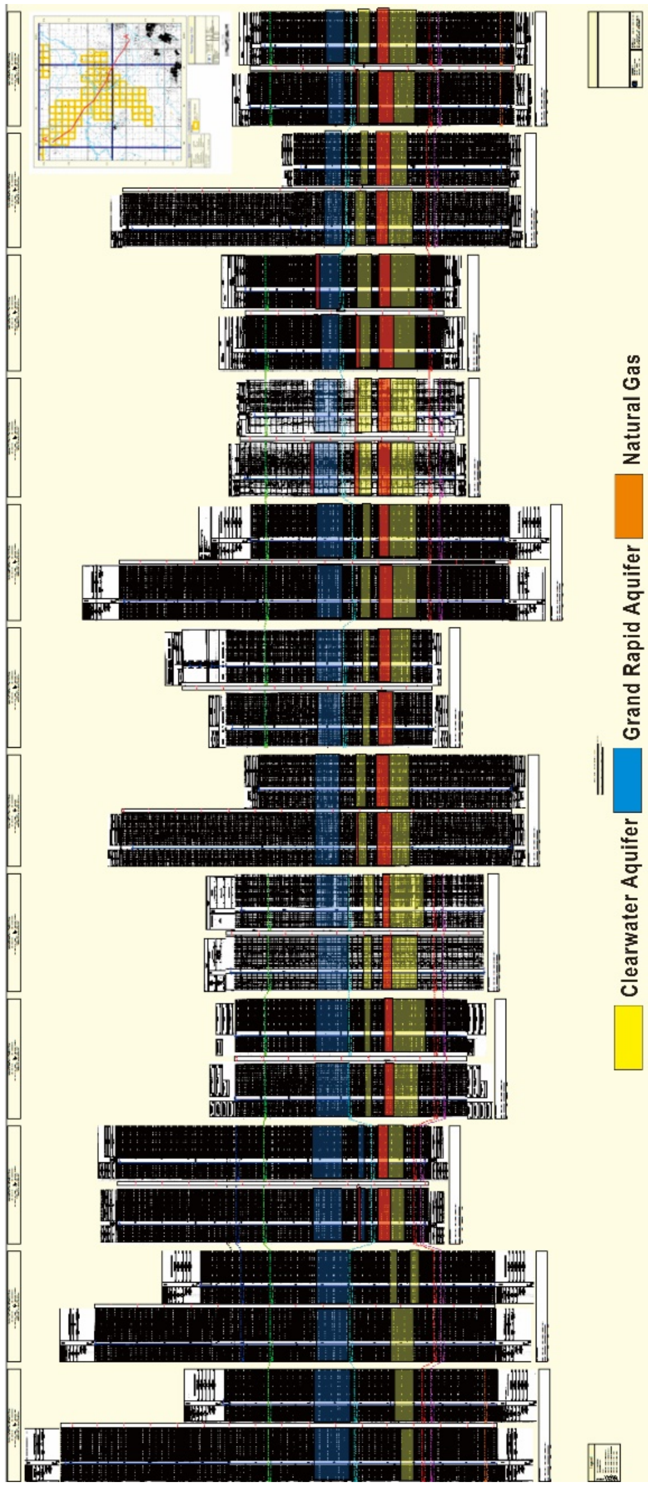

Figure 8 Well Logs interpretation (local scale – right cross Leismer Lease): gas cap, Clearwater sandy, and Grand Rapid units, and top picking of other formation tracing laterally alone local section A-A'

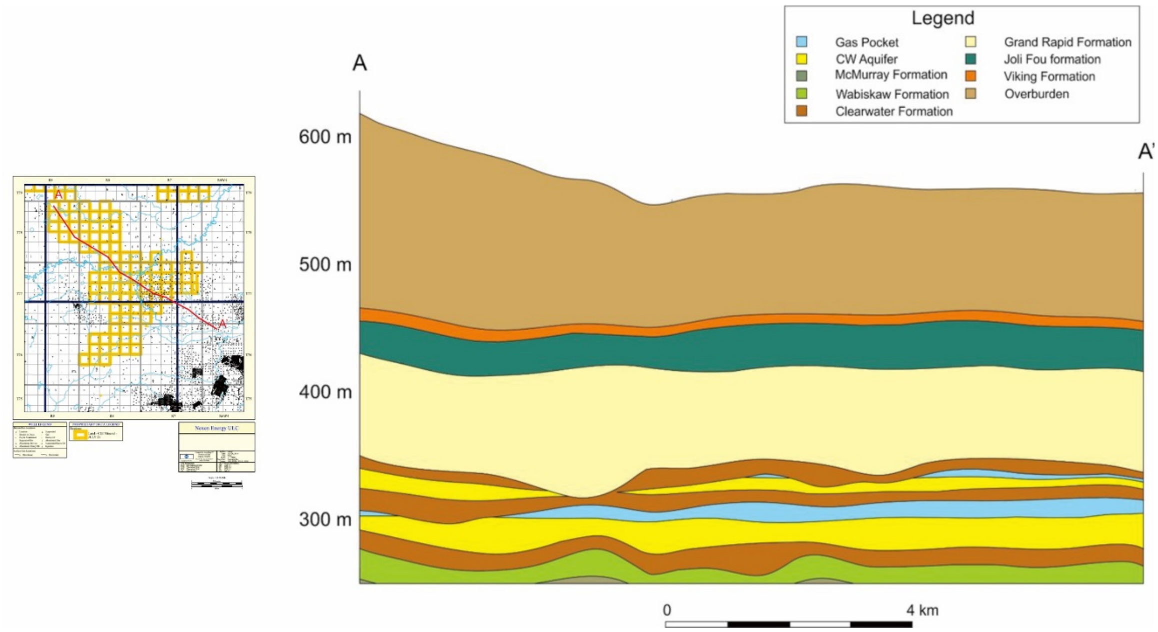

Figure 9 Geological model cross-section along section A-A'

2.2 Regional Hydrological Background

The study site is within the Athabasca River Watershed. Hydrostratigraphic units are based on the thorough interpretation of geological formation, groundwater flow and hydraulic properties. Miall (2013) summarized hydrogeological studies in lower Athabasca region which are carried out by Barson et al. (2001) and by Worley Parsons Canada Ltd. (2010). The Figure 10 presents hydrogeological units present in Athabasca Basin includes several interbedded aquifers and aquitard units from Quaternary age to Cretaceous age and end on Devonian carbonates unconformable. In the Mannville Group, three major hydrostratigraphic units can be discerned: Wabiskaw aquifer/aquitard at bottom, Clearwater aquifer/aquitard and Grand Rapids aquifer at top (Bachu & Underschultz, 1993). The schematic cross-section of stratigraphy covers from top overburden sediment and the Upper Cretaceous.

Figure 11 explicitly indicates regional features of groundwater flow system, which will be further discussed in following section. It indicates some features of regional groundwater flow. Surface recharge is at topographic-high area in the southeast and at the Stony Mountain upland in the center of the study area, and discharge mainly towards river valleys (Bachu & Underschultz, 1993; Barson et al., 2001; Tóth, 1978). Lateral flow within the Upper Cretaceous and overburden aquifers are dominated by upland areas such as the Stony Mountain Uplands and the Mostoos

Hills Upland; meanwhile, the lateral flow directs the groundwater flow from this area towards topographic low area, such as the Clearwater and Athabasca river valley (Bachu & Underschultz, 1993; EnCana, 2009). Vertical gradient is driven by local topography from recharge at central highlands, which suggests a potential downward flow gradient from groundwater surface infiltrating through over burden to Devonian bedrock. The steep vertical pressure differences within each aquifer system drive the flow through Joli Fou Aquitard, the Clearwater Undifferentiated Aquitard and the Wabiskaw Shale Aquitard (Toth, 1995). However, there is limitation of groundwater mix between Cretaceous and Devonian aquifer based on evidence of differential salinity. The chemical character of water in Cretaceous succession also dominantly suggests meteoric-recharge origins with long-residence time and slow path (Barson et al., 2001).

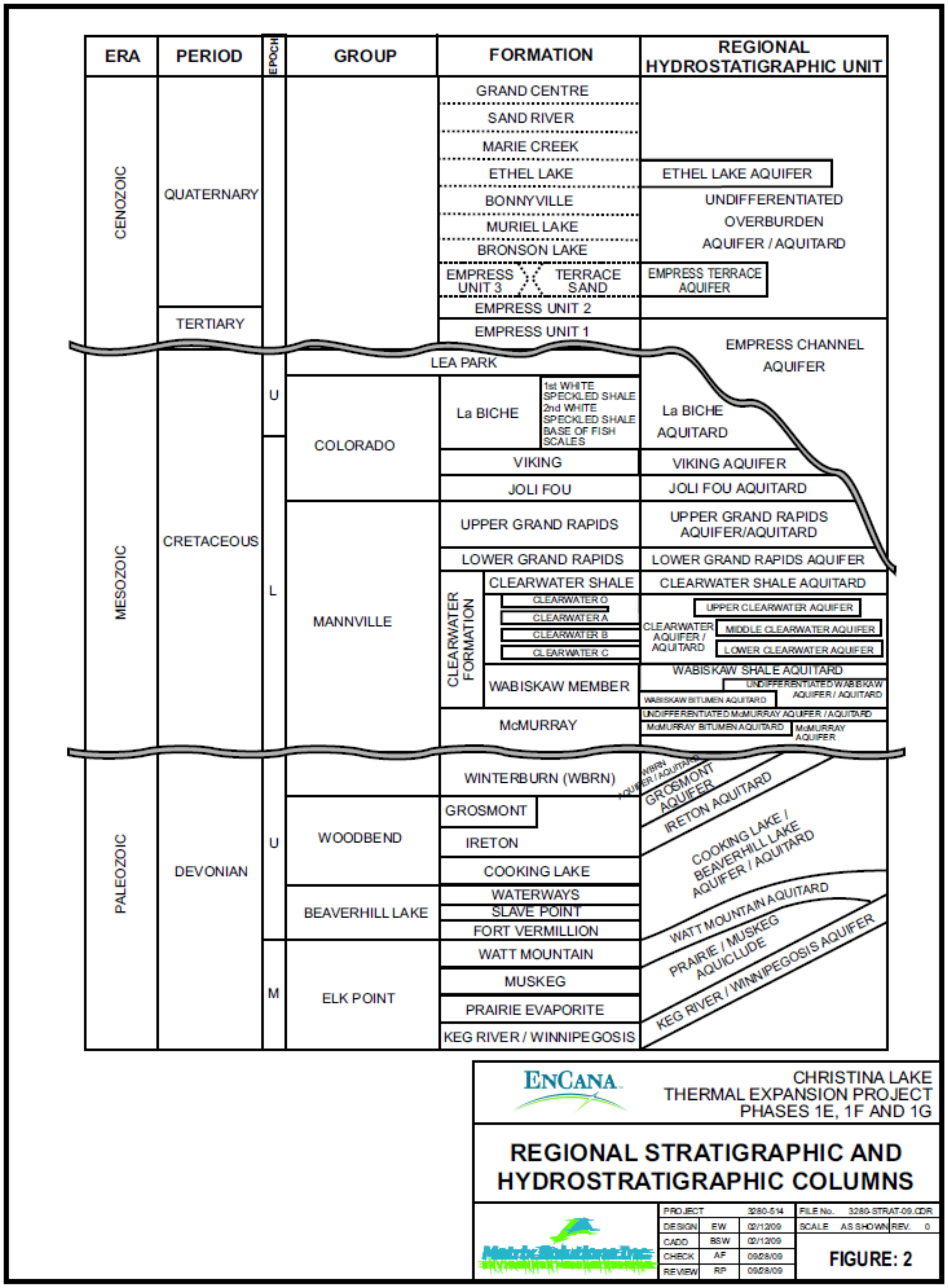

Figure 10 The hydrostratigraphy of the Athabasca Oil Sands (EnCana, 2009)

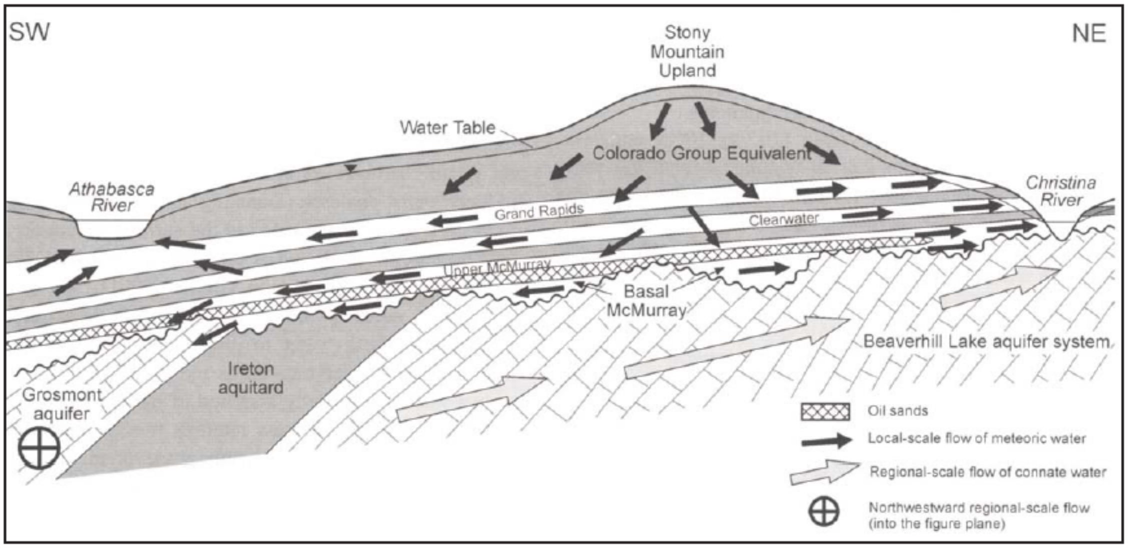

Figure 11 The hydrogeology of the Athabasca Oil Sands ((Barson et al., 2001) (permission granted from the Bulletin of Canadian Petroleum Geology)

The primary aquifers, including Clearwater A, B and Grand Rapid B, are laterally continuous with relatively even thickness. Despite some irregular pressure dimples from onsite observation caused by pumping water/gas events, it is not expected to see a significant vertical downward flow. Jervey (2003) gave a comprehensive description on stratigraphy, facies and water resource potential for Clearwater Formation in the entire study area. Clearwater Formation is distal marine facies interlayered by three thick shore-face sands with a roughly SE-NW trend in the project area. The massive sandstone unit is subdivided to Clearwater A, B, C, all with unconsolidated, well to moderate sorted, fine to medium grained sandy features. The well log interpretation shows hydrogeological units in Clearwater Formation in Figure 5.

According to the Nexen regional investment, Lower Grand Rapids aquifer and Clearwater B is regards as make-up water aiming aquifers within study area (Nexen Inc., 2015). Based on Nexen Leismer Project report, additional water resource requirement is not only for prospective Leismer Project, but also for the on-going K1B Project. To satisfy the certain requirement of start-up water of K1B project and future Leismer Project, water resources within Leismer Lease have been targeted as reserved water resource, including major Upper McMurray Aquifer, Grand Rapid Aquifer, and subordinate Clearwater B aquifer. Nexen water team did aquifer test on two wells in Leismer Project to assess water chemistry and water deliverability potential of aquifer for future well completion (Matrix Solution Inc., 2008a, 2008b). Clearwater B aquifer is considered as an ideal saline aquifer for make-up water supplement with up to 574 m^3/day delivery (Farvolden method) (Alberta Environment, 2003). There are two wells completed in the Clearwater B sand at 10-08-076-08W4 (UWI 1F1/10-08-076-08W4/00) and at 11-21-076-08W4 (1F1/11-21-076-08W4/00), drilled and tested at south boundary of the Leismer Leases (Matrix Solution Inc., 2008a, 2008b). Relevant parameters and aquifer capacity was estimated with a modest long-term rates at 176 m^3/d and 100 m^3/d respectively. Some important hydrogeological parameters can also be obtained from pumping test as a reference resource. Gas exsolution process is commonly observed during the pumping test as a concern of well lock issue. The exsolved gas potentially compensates the pore pressure decline, which should be a research value in multi-phase simulation consideration.

Most oil sands operators also identify Grand Rapid Formation, Clearwater Formation and McMurray Formation as main groundwater source for steam operation, because the sandy aquifer is laterally more extensive than glacial and pro-glacial sands. According to Statoil report (2014) as an example, 90 percent of groundwater is used to generate steam within Leismer Demonstration Project. However, extension on production is under future perspective as the regulatory approval more production; additionally, new projects, such as Nexen Leismer Project, will be on development. Preparation has been underway for increasing demand on steam generation and Clearwater B aquifer is the spare saline groundwater source when Grand Rapid Formation is expected to be phased out. Withdrawing water from Clearwater B aquifer has been approved by regulator and major operator. Operators, including Cenovus, Devon and Statoil, have drilled supply wells and corresponding monitoring system on-site (Statoil, 2012).

Chapter 3

Methods

The process that transforms geological and hydrogeological information and conceptual mechanism to computer simulation includes the conceptual model, parameterization of the numerical model, and the mesh design. In the following section, a briefly description of hydrologic features of the study site and construction of conceptual model is presented, followed by the description of the site literature-based and calibrated data which are used as key parameters in the simulation. Eventually, the establishment of numerical model through CompFlow Bio and HydroGeoSphere is depicted, as well as how we introduce gas production issue in the simulation.

3.1 Conceptual Model

A conceptual framework should be drawn preliminarily which perform as a benchmark to assist the cooperation of simulated results from CompFlow Bio and HydroGeoSphere models. This including: 1) the approximate geometry of domain and conceptual hydrostratigraphy 2) boundary conditions 3) the hydraulic parameters of all formations 4) location of existing gas cap in multi-phase model and assumed gas cap in single-phase model 5) the methodology incorporating replication gas pumping in a single-phase model. The conceptual model is the preliminary understanding based on geological section and regional hydraulic features. Groundwater flow in the model area and implement of model though all the assumptions can be summarized below based on conceptually summary by Barson et al. (2001) and EnCana (2009):

- Vertical gradient within the Quaternary, Tertiary and Cretaceous sediments suggests a downward directed flow potential from ground surface to Devonian bedrock throughout most of the study area, indicated by successively declined hydraulic head (Toth, 1995). A specific precipitation infiltrates over the model area can be estimated from historical data. The recharge of groundwater infiltrates downwards through primarily low permeable drift material into underlying Cretaceous aquifers eventually. Korea National Oil Corporation (2008) provides the estimated annual recharge rates of the order of 20 mm/year in Fort McMurray, while the study conducted by Gulf Canada Resource Limited (2001) states a rate of 7.3 mm/year. The recharge event is implemented by assign a slice of nodes at the top of model to constantly introduce water into the numerical model, which simulates the recharge events over the surface.

- Based on discussion in EnCana (2009), horizontal flow in aquifers throughout the entire of the study area is generally directed north toward the Clearwater and Athabasca River valleys or west toward the sub-crop location of the Grosmont Aquifer. However, the local groundwater pumping for current operation project interrupts the pressure system to some extent. As model domain only covers a small section of entire regional system, lateral flow can be assumed slow enough to be neglected. In the numerical model, bottom-sides boundaries are considered as equalized hydrostatic condition.
- The model domain will be constructed in simple case and will be represented in 2-dimensional vertical slice bounded by ground surface and terminated at the top of cap rock Wabiskaw Formation, which is an appropriate slice containing geological features and hydraulic conditions. The lateral extent of the model will cover the cross-section A-A' in Figure 7, covering through the main Clearwater B gas pool. Each formation is traced through well logs along section A-A' by picking the tops of each formation (Figure 7). The geometry of structure controlled gas pool is the main target when depicting the model mesh. The conceptual hydrostratigraphy incorporated into the numerical model is discussed in parameterization section. There are three aquifers and four aquitards contained in numerical model. Geologic and hydrostratigraphic interpretation is generated from top structure and Isopach maps prepared by Nexen (Golder, 2005b) and KNOC (Korea National Oil Corporation, 2008). The natural gas pool distribution and cross-section feature is mapped and constructed based on the well log data (Figure 6). Instead of using top Structure and Isopach map, well log tops alone the aiming cross-section is used to construct expected geometry features of Clearwater B and on-top undifferentiated aquitard.
- Hydraulic conditions within study area are reviewed from several regional groundwater model reports. Selected surface elevation and Isopach of hydrostratigraphic units are essential to build up model layer framework and formation continuity, especially the targeting Clearwater B. Calibrated hydraulic head map for each formation is reliable for boundary setting in numerical model.

The conceptual model elements listed above are implemented into numerical model by CompFlow Bio and HydroGeoSphere through the setting of model domain framework, model parameterization and boundary condition stated in the following section.

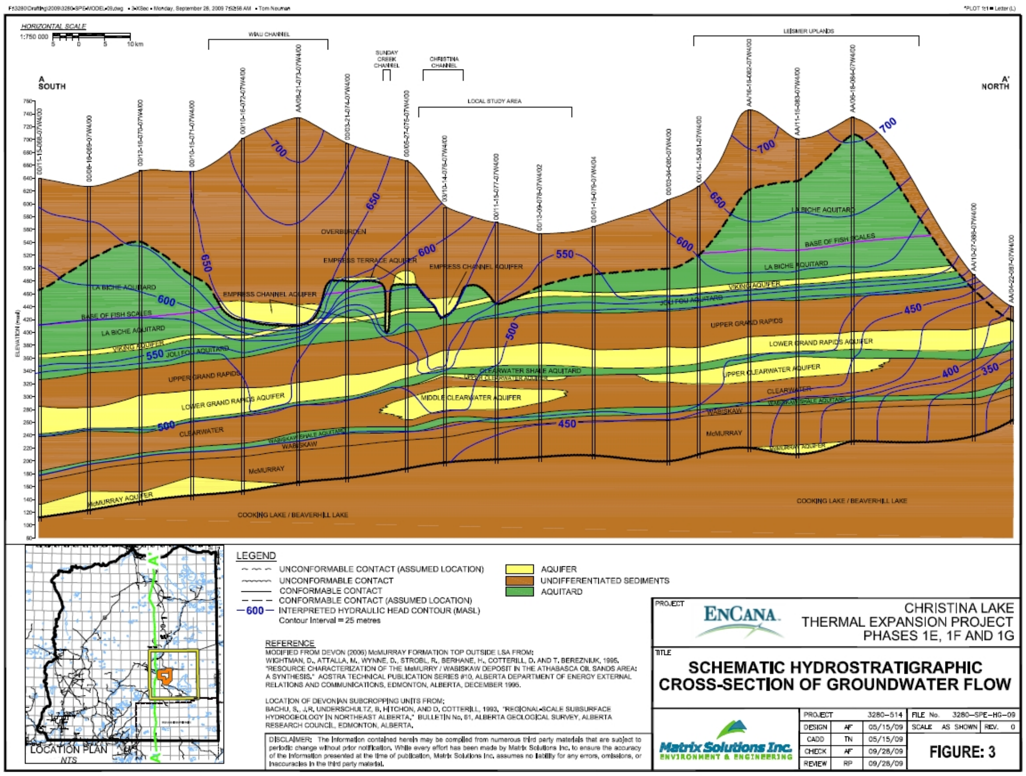

Figure 12 Schematic hydrostratigraphic cross-section of groundwater flow (EnCana, 2009)

3.2 Numerical Model

We use CompFlow Bio and HydroGeoSphere as simulation candidates to apply the framework of conceptual model into numerical simulation.

CompFlow Bio is chosen to perform a multi-phase simulation on this topic. We introduce two fluid phases (aqueous and gas phases). Model domain represent the local geological formations from overburden material to under Wabiskaw shale, which are assigned with appropriate physical properties. The spatial formulation is in pseudo-2D cross-section. As we focus on capture gas production impact on aquifer pressure system, we emphasize on setting up reservoir geometry and ideal. In brief,

> *"CompFlow Bio is a three-phase, multi-component, isothermal numerical simulator for flow and transport. It uses a first-order accurate, finite-volume numerical scheme to solve the multi-component advection, dispersion equation in three spatial dimensions."* (Walton, 2013)

HydroGeoSphere uses Richard's Equitation governing 3-D unsaturated/saturated subsurface flow. HydroGeoSphere is regarded as a powerful numerical simulator developed for supporting water resource and engineering projects pertaining to hydrologic systems with both surface and subsurface flow and transport.

> *"HydroGeoSphere code provides a rigorous simulation capability that combines fully-integrated hydrologic/water quality/subsurface flow and transport capabilities with a well-tested set of user interface tools" (Therrien, McLaren, Sudicky, & Panday, 2010).*

In this section, relevant parameters required for the numerical simulation are described, including: summary of hydraulic parameters, a description of boundary conditions, k_r-S-P_c relations of the targeting aquifer and ceiling aquitard, and a brief introduction of k_r-S-P_c principle.

3.2.1 Numerical Domains

Hypothetically, a pseudo-3D (narrow in y- direction) is been chosen to perform numerical simulation. Due to the simplified geological setting and computational limitation, to generate a real 3-D model domains and capture real production is extremely difficult. Besides, the historical gas and water pumping information from each operators is confidential and difficult to achieve, the calibration process is not considered as first-order based on study objectives. A pseudo-3D domain slide is appropriate to apply in this study case. Less involved nodes number reduce each running time and increase the simulation efficiency. Thus, presudo-3D domain is appropriate for a preliminary and conceptual study. Figure 13 depicts pseudo-3D numerical model domains considered along the cross-section showing in Figure 5, covering the entire Leismer lease in NW-SE direction. The domain has an approximately 130,000m length in x direction, 325m depth from surface elevation (z direction), and 2m thickness in y-direction. The surface elevation is selected by using average value along cross-section. Hydrostratigraphic units are simplified as horizontal layer, except Clearwater B aquifer. The geometry of dome-shaped Clearwater B aquifer is according to well log interpretation along the section crossing Clearwater B main gas pool described in Figure 7. The domain discretization is represented by mesh density. The variation of mesh density depends on the location and geometry of Clearwater Formation and gas component appearance, particularly for Clearwater B gas pool as well as the area adjacent to model boundary. Ten fine layers are also assigned on top of domain surface in order to get water table location and observe the recharge event in vadose zone at ground surface

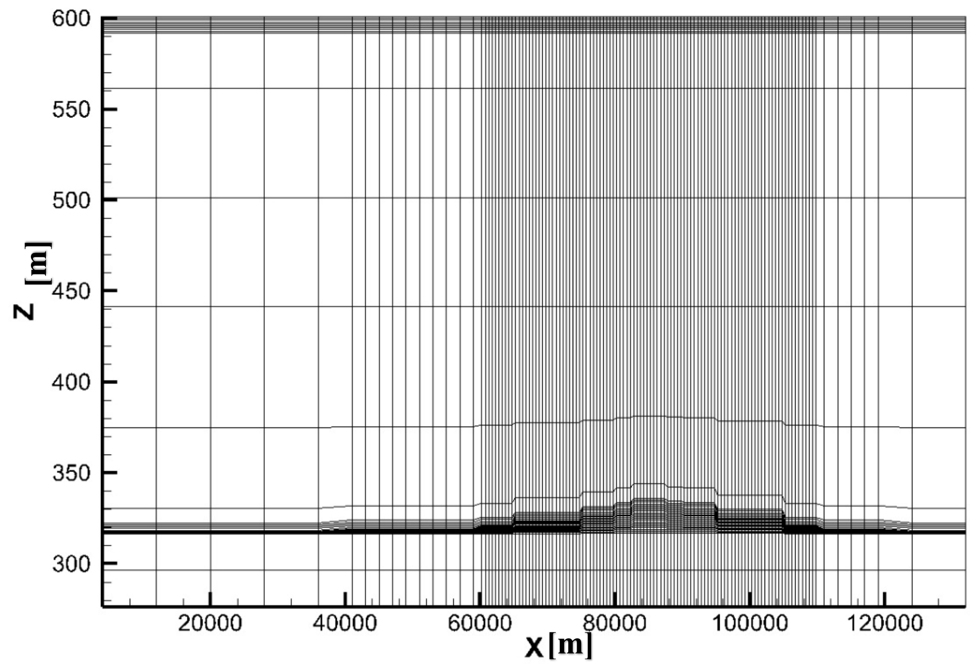

Figure 13 Numerical model domain and mesh design shown in X-Z plan.

3.2.2 Boundary Conditions

The boundaries imposed in the model include bottom hydrostatic boundary, both left and right sides hydrostatic boundaries, recharge boundary and no-flow boundary. Figure 14 presents the scope of boundary conditions in the model. Hydrostatic boundary inject or remove components to maintain the boundary at predefined pressure (or hydraulic head value) (Walton, 2013). Hydrostatic boundary is applied along the left and right ends of Clearwater B Aquifer and Wabiskaw Aquitard, shown in reddish twill slide. The pressure value represents a constant head value of both sides' boundaries that is equivalent. The reason of ignoring the lateral flow in aquifers is due to extremely low later gradient referred from historical monitoring well data and calibrated regional model (Figure 12). For each nodes involves in the sides boundary, equal pressure value is assigned, which means each nodes contains same hydraulic head value and no vertical flow is allowed alone the boundary sides. However, lateral groundwater flow is performed freely drawn or injected to the domain through sides' boundary balancing the pressure system. The residual part of sides boundaries is assigned no-flow boundary. Any phase cannot be allowed to flow through these boundaries, which mean there is no lateral flow cross the domain above Clearwater B.

The bottom slide of Wabiskaw Aquitard is also assigned as constant aqueous phase pressure to each nodes in bottom slide to maintain a water table and natural vertical hydraulic gradient across the whole domain. Respectively, the three boundaries mentioned above allow inflow and outflow of both aqueous and gas phase. The spacial hydraulic condition within study area is referred from former regional groundwater modeling, including the simulation work in and Nexen Long Lake Project (Golder, 2005a, 2005b), and KNOC BlackGold Expansion Project (Harvest, 2012).

Recharge boundary was added on the top layer of model domain with a constant rate to assist to generate a natural vertical gradient flow. Recharge rate is assumed as first-order parameters for boundary setting. In CompFlow Bio model, recharge boundary is implemented by multiple instantiations of the constant rate component injection boundary (Walton, 2013). The rate is adjusted passively so that water table is at or just below the ground surface. In addition, the top layer is also assigned as constant pressure equal to atmospheric pressure equal to 100 kPa. In HydroGeoSphere model, the recharge boundary is set as fix injection rate as 25mm/year (8×10^{-10} m/s) cross the top layer, which based on regional estimated recharge rate. The boundary conditions described above initially attempt to simulate a pseudo-steady-state condition and to maintain a static water pressure. This stage is regarded as pressure system initialization for gas pumping simulation. In transient-flow simulation stage, source and sink terms are added into system to mimic gas reservoir generation and gas production (CompFlow Bio). Some adjustment on sink term will be slightly substituted in single-phase model simulation.

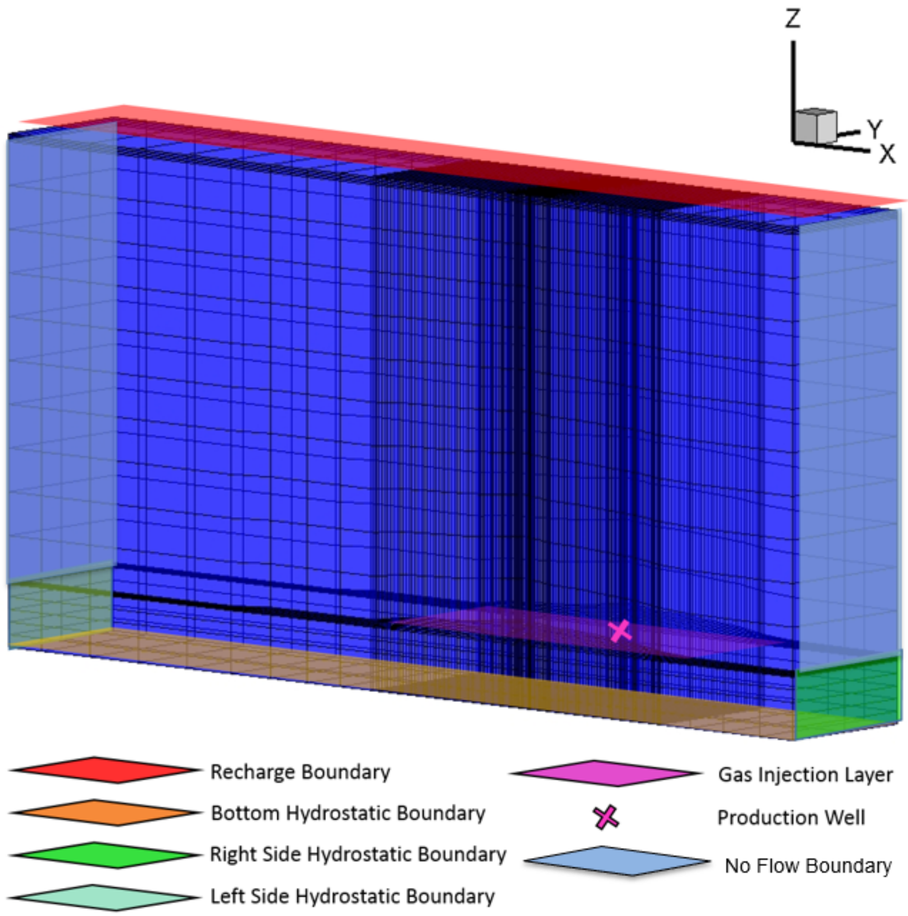

Figure 14 Boundary conditions and source/sink term for gas pool generation and gas pumping steps (CompFlow Bio)

3.2.3 Parameterization

Description of relevant subset of the first-order parameters required for numerical simulation are reviewed and summarized in the following subsection. As the study objective is ultimately driven to a conceptual understanding of hydraulic head drawdown due to gas pumping, assumptions are made to simplify the parameterization. Both CompFlow and HydroGeoSphere assumes the system as isotherm, groundwater is fresh, and gas component is also considered of second-order parameters (use air instead of methane) because the exsolution process has limited impact to compensate the pressure loss. .Therefor, only some first-order instinctive physical parameters are discussed in the following section, including hydraulic parameters and intrinsic porous media k_r-S-P_c relations. Each formation is defined by geostatistical description including porosity and permeability in x, y, x direction. The theory of k_r-S-P_c relations is discussed in the following subsection. A summary of relative permeability and capillary pressure table are assigned for Clearwater B aquifer and above aquitard respectively.

3.2.3.1 Hydraulic Parameters

Discussed in previous section, the model is represented in pseudo- 3dimensional slice covering the geological units from the ground surface to the top of Wabiskaw Shale Aquitard. As the stratigraphic layers have been simplified into horizontal layers, hydraulic conductivity and porosity should be regarded as first order parameters governing the flow system and drawdown magnitude. Table 1 summarizes hydrostratigraphic units and assigned hydraulic parameters. The parameters are inversely estimated through calibrated groundwater water model simulated within the aimed aquifer system. The data source is from collaborated parameters applied in regional groundwater modeling achievements of Athabasca Basin, including Jeckfish Project (Devon, 2006), Christina Lake Project (EnCana, 2009), Leismer Demonstration Project (Statoil, 2009), BlackGold Expansion Project (Harvest, 2012), etc.. Alternatively, the parameters of two mayor aquifers, Clearwater B Aquifer and Grand Rapid Aquifer, are referred from both pumping test and calibrated model approaches. The physical parameters manipulated include vertical and horizontal hydraulic conductivity, and porosity. Hydraulic conductivity value is finally convert into permeability and represents in x-, y-, z- directions in CompFlow model. In addition, we neglect the various water components in domain system. The water we introduced in both multi-phase model and single-phase water is assumed as uniformly fresh water with density of 1 kg/m^3. Another assumption in multi-phase model is we are using air instead of methane in gas pocket. The air is assumed insoluble in aqueous phase, with ideal air properties.

Table 1 Hydrostratigraphic Units and Assigned Hydraulic Parameters

	Hydraulic Conductivity [m/s]	Porosity

	Horizontal	Vertical	
Undifferentiated Overburden Materials	2.1×10^{-7}	8.0×10^{-9}	0.30
La Biche Aquitard	1.0×10^{-5}	3.0×10^{-8}	0.40
Joli Fou Formation	1.0×10^{-7}	1.0×10^{-10}	0.37
Upper Grand Rapid Aquifer/Aquitard	1.6×10^{-5}	1.0×10^{-9}	0.35
Lower Grand Rapid Aquifer	1.0×10^{-5}	3.0×10^{-6}	0.27
Clearwater A Aquifer	1.0×10^{-3}	1.3×10^{-4}	0.30
Undifferentiated Clearwater Aquitard	3.0×10^{-7}	2.0×10^{-10}	0.40
Clearwater B Aquifer	3.4×10^{-4}	4.0×10^{-5}	0.27
Wabiskaw Shale Aquitard	3.0×10^{-7}	1.0×10^{-10}	0.35

3.2.3.2 Capillary Pressure and Relative Permeability Theory

A main target in multi-phase model is to generate a gas pocket close to the real geometry and saturation. Gas should be perfectly trapped below the overlying aquitard under the combined barrier of relative permeability and capillary pressure. Relative permeability and capillary pressure, regarded as first-order parameters, are the two critical parameters to generate prevent gas moving upwards into aquitard. In a gas reservoir, the rock initially contains water and is water-wet. Gas phase appears later and migrates upwards under the force drive of buoyancy. When the driving force is insufficient to come over the capillary force, the gas phase is trapped under the cap rock intimately controlled by the size of pore size and respective displacement pressure.

There are several laboratory methods to determine rock sample relative permeability and capillary pressure. The challenge is the insufficient tests and measurements that performed on core samples from petroleum and natural gas operation project. Reservoir engineers face the challenge of the limitation of petro-physical properties, which influence characterization of multi-phase flow as well as predication on reservoir production and recovery performance. Besides, the reliability of laboratory of measurements is another aspect impacting on practicing analysts (Angeles, Torres-Verdín, Hadibeik, & Sepehrnoori, 2010).

Quoting from the lithological discretion and geological feature report generated by Jervey (2003), an important feature of Clearwater B aquifer within Leismer Lease is “unconsolidated fine to medium-grained sandy material". It implicitly indicates it is possible to perform a core sample test to get relative petrophysical properties of Clearwater B unit. Consequently, manually modifying unknown parameters as well as validating curves performance in numerical model becomes a primary prerequisite step.

The following work presents the process to develop an appropriate methodology to estimate saturation-dependent rock properties applied in our model, under the circumstance of lacking core test data. By using the modified Brook-Corey Method, saturation-dependent capillary pressure and relative permeability can be modified under 8 independent parameters: S_w is water saturation; k_r is relative permeability, P_{ce} is capillary entry pressure, η is the pore size distribution index, m is Corey's number of brine, n is Corey's number of methane. The modified data is for Clearwater B and undifferentiated aquitard. Parameters are referenced from a CO_2 storage study in Western Canada Basin by Bennion and Bachu (2010).This study describes a serious process of drainage and imbibition CO_2/brine system for a sandstone formation. The samples listed on table are all from northern part of the Alberta Basin; in addition, the pore size distribution, porosity and capillary were measured using mercury/air system. It can be scaled to generate appropriate air (methane)/water systems in our study. Although the Clearwater Formation samples were extracted from relative shallow cores, it is still reasonable to approximately be used as physical parameters of Clearwater Formation once considering the stratigraphy continuity.

The resulting relative permeability as well as capillary pressure as a function of saturation is presented in Figure 15 (data from table 1 and 2). It is the fundamental definition and first-order parameters to simulate gas-phase advection behavior through porous media in CompFlow Model. Relative permeability is a concept of permeability reduction in flow capability due to the presence of multiple mobile fluids (in our case is a dual-phase system- gas and water). As capillary pressure exists, each fluids permeability reduces as a non-linear relationship with saturation, until reaching critical point (immobile point). The critical points at different critical saturation for aquifer and aquitard restrict the gas mobility cross the boundary of aquifer and aquitard. The second barrier is generated from capillary pressure. The capillary pressure differences are due to distinctive sediments characters and pore size and distribution. For a certain saturation condition, the capillary pressure value differences exist between aquifer and aquitard, known as entry pressure barrier. Once the gas phase pressure is below the aquitard entry pressure, gas will be sealed beneath the aquitard. The combination of these two barrier forms the gas pool naturally.

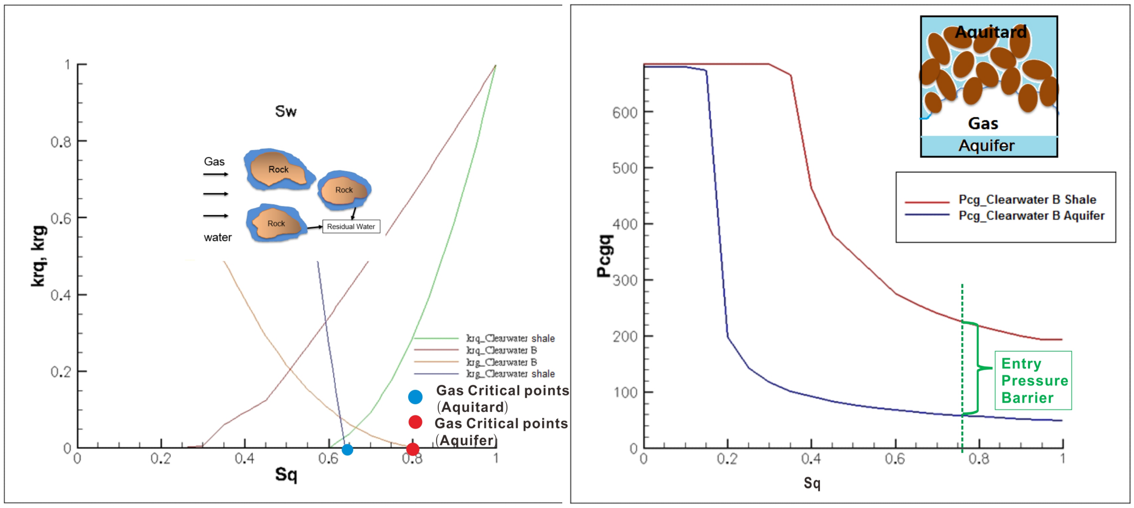

Figure 15 Relative permeability curves and capillary pressure curves as a function of saturation of Clearwater B aquifer and aquitard

Table 2 Relative permeability and displacement characteristics for the imbibition cycle in gas/water systems for rock samples from Western Canada Basin (Bennion & Bachu, 2010)

	Clearwater B Aquifer	Undifferentiated Aquitard
k_{rw} max	1	1
k_{rg} max	0.494	0.545
S_{gr}	0.145	0.359
S_{wr}	0.343	0.566
P_{ce} (kPa)	49	193
m	1.150	2.030
n	2.250	1.150

$\boldsymbol{\eta}$	0.510	0.450

Data presented above are fitted into following modified Brooks-Corey equations, in which relative permeability is a function of phase saturation and rock properties.

$$\boldsymbol{k_{rw}(S_w) = k_{rw}^{max}\left(\frac{1 - S_g - S_{wr}}{1 - S_{wr}}\right)^{m}}$$

$$\boldsymbol{k_{rg}(S_g) = k_{rw}^{max}\left(\frac{S_g - S_{gr}}{1 - S_g^{irr} - S_w^{irr}}\right)^{n}}$$

$$\boldsymbol{P_c(S_w) = P_{ce}\left(\frac{S_w - S_{wr}}{1 - S_{wr} - S_{gr}}\right)^{-1/\eta}}$$

(Bennion & Bachu, 2010; Brooks & Corey, 1964)

Table 3 Relative permeability-saturation and capillary pressure-saturation data for the aqueous-gas phases of Clearwater B aquifer

S_q	k_{rg}	k_{rq}	P_{cgq} [kPa]
1	-	1.000	41.93
0.95	-	0.934	44.06
0.9	-	0.846	46.49
0.85	0.000015	0.760	49.30
0.8	0.0033	0.674	52.61
0.75	0.014	0.590	56.56
0.7	0.034	0.508	61.39
0.65	0.063	0.427	67.46
0.6	0.103	0.348	75.38
0.55	0.154	0.271	86.30
0.5	0.217	0.197	102.58
0.45	0.291	0.127	130.35
0.4	0.379	0.062	193.23
0.35	0.479	0.006	716.64
0.345	0.490	0.0013	1568.00

Table 4 Relative permeability-saturation and capillary pressure-saturation data for the aqueous-gas phases of Clearwater Undifferentiated Aquitard.

S_q	k_{rg}	k_{rq}	P_{cgq} [kPa]
1	-	1	98.35
0.85	-	0.972	115.75
0.8	-	0.656	124.68
0.75	-	0.403	136.73
0.7	-	0.212	154.41
0.65	-	0.083	184.63
0.64	0.003	0.064	193.79
0.638	0.012	0.061	195.83
0.636	0.023	0.057	197.95
0.63	0.058	0.048	204.84
0.62	0.124	0.034	218.55
0.61	0.195	0.022	236.27
0.6	0.270	0.013	260.57
0.59	0.347	0.007	297.24
0.58	0.426	0.002	363.68
0.57	0.508	0.00021	570.38
0.565	0.550	0.00002	870.31

Chapter 4

CompFlow Numerical Model Approaches and Results

The objective of the CompFlow model is to parameterize the numerical model with geological model, and assess the hydraulic head behavior under gas production. In particular, we focus on three processes.

1) Define appropriate porous media properties for each formation based on former simulation results and sample test, in order to represent geological model and to assist generate a proportional gas pool in Clearwater B.
2) Perform gas pumping from Clearwater B gas pool and observe the hydraulic head behavior.
3) Compare the simulated hydraulic head drawdown with on-site observation, and create a methodology to replicate CompFlow model approaches into single-phase numerical model.

Two phases, aqueous and gaseous, are involved in CompFlow Bio model. As a frontier and conceptual attempt to capture the issue, we simplify the model simulation by hypothesizing the gas phase is immiscible to aqueous phase, and the water is fresh water. The postulation is due to the complex process of depressurization accompanies with gas exsolution. Under the framework of conceptual model and numerical model design, we attempt to perform a gas production scenario via CompFlow bio by introduce the following two steps:

1) Create antecedent conditions
    a. Steady-state simulation to create prospective antecedent hydraulic setting and condition prior to introduce gas phase
    b. Injecting gas phase into Clearwater B dome to generate gas pool
    c. Re-approaching steady-state condition and forcing gas to redistribution under buoyancy-drive
2) Transient-state to perform gas pumping and observing hydraulic head drawdown

To create antecedent conditions, the whole domain should reach steady-state under adjustment of each hydrostatic boundaries in advance. Both sides of Clearwater B are assigned hydrostatic condition with 475m head value, which is modified from previous simulation work. The entire system reaches a pseudo-steady-state condition after approximately 600 year's simulation time (Figure 16). The water rate flowing in or out the domain through each boundary reaches constant, which represents a pseudo-steady-state condition. The head contour shows an expected vertical gradient in Figure 16. Figure 17 indicates all boundary performances reach balance after 4×10^6 days simulation time. It takes about 3×10^5 day's simulation time for model to reach hydrostatic condition as flow rates of every boundary reach constant.

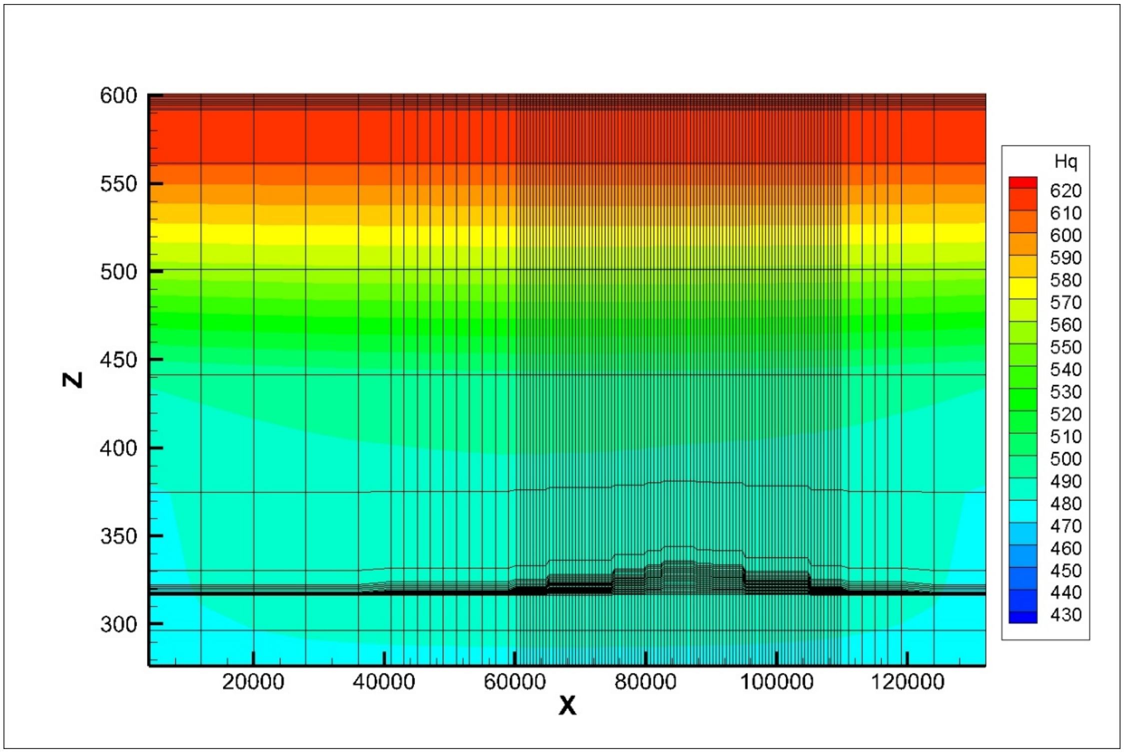

Figure 16 Hydraulic head contour under hydrostatic condition at end of steady-state simulation stage

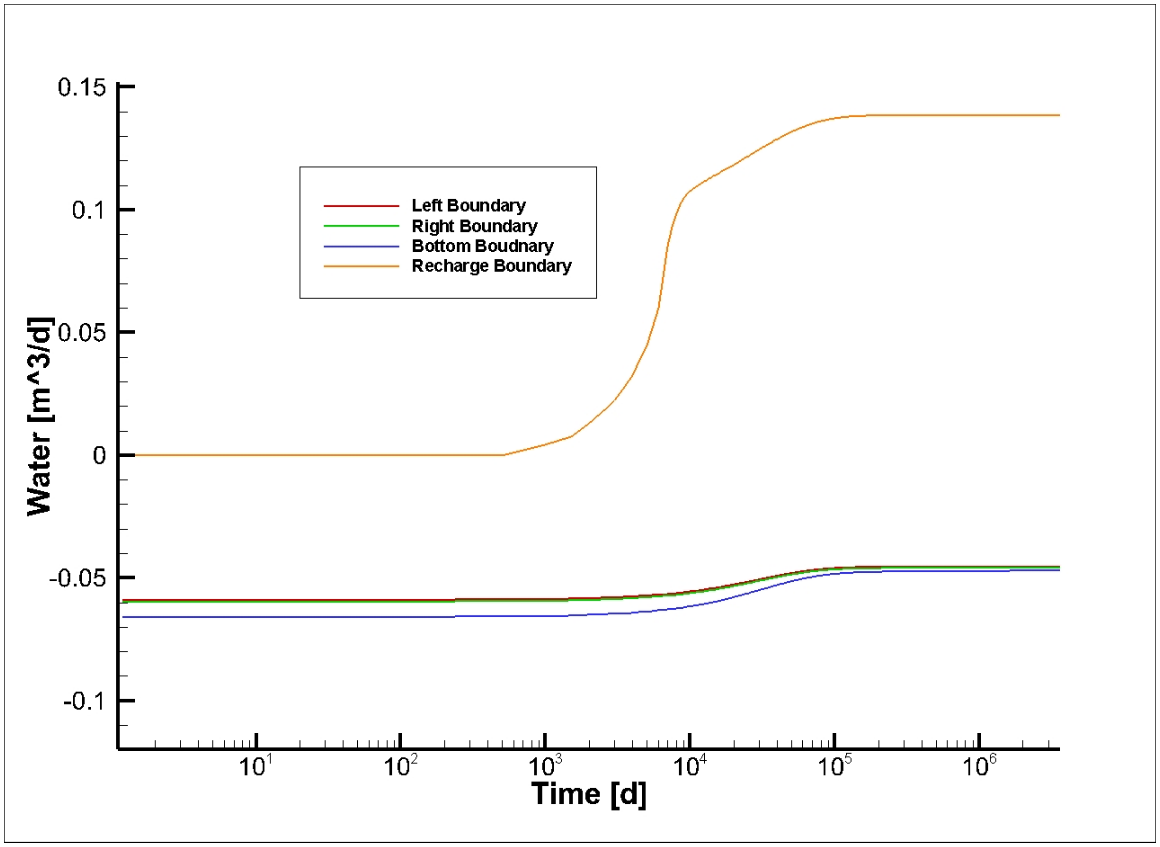

Figure 17 Boundary reaction under steady-state simulation stage until reaching hydrostatic condition

In the following stage, the boundary conditions maintain the same setting. In order to replicate and to generate a gas pocket matching the real gas pocket geometry and saturation, 28 injection wells are introduced. The injection wells are represented by injection nodes of source term in CompFlow, attempting to introduce gas phase into Clearwater B Aquifer. Each node's injection rate is constant. Several injection rates are used (shown as brown dash lines in Figure 19): higher injection rates are set for the well screens close to dome center, and rates are set gradually lower as the well screens away from the dome center. The purpose is to avoid of gas spillover from edges of Clearwater B.

To observe the gas phase loading process, we prepared a series of plots in Figure 18 illustrating the evolutionary process of steady gas injection. Gas phase is introduced into water-saturated system around dome center. Meanwhile water phase is forced to flow out from the domain from mainly sides and bottom boundary as a response of gas phase occupying pore space. Additionally, gas injection influences the infiltration from recharge boundary which reflecting a slightly decline on infiltration rate (shown in orange curve in Figure 19). Subsequently, gas phase floats upwards under buoyancy driving and accumulates in the dome center. Gas is trapped under interface of upper aquitard by a combined barrier of relative permeability and capillary pressure contrast between Clearwater B Aquifer and overlying aquitard. As more gas is introduced into the dome, the gas pool is eventually generated, and gas phase migrates along at the top of Clearwater B aquifer and extended laterally simultaneously. After 275 years' simulation time under constant injection rate, gas concentration reaches 0.7 in the dome center, which matches our initial expectation. The distribution and geometry of the gas cap is very consistent to the geological investigation.

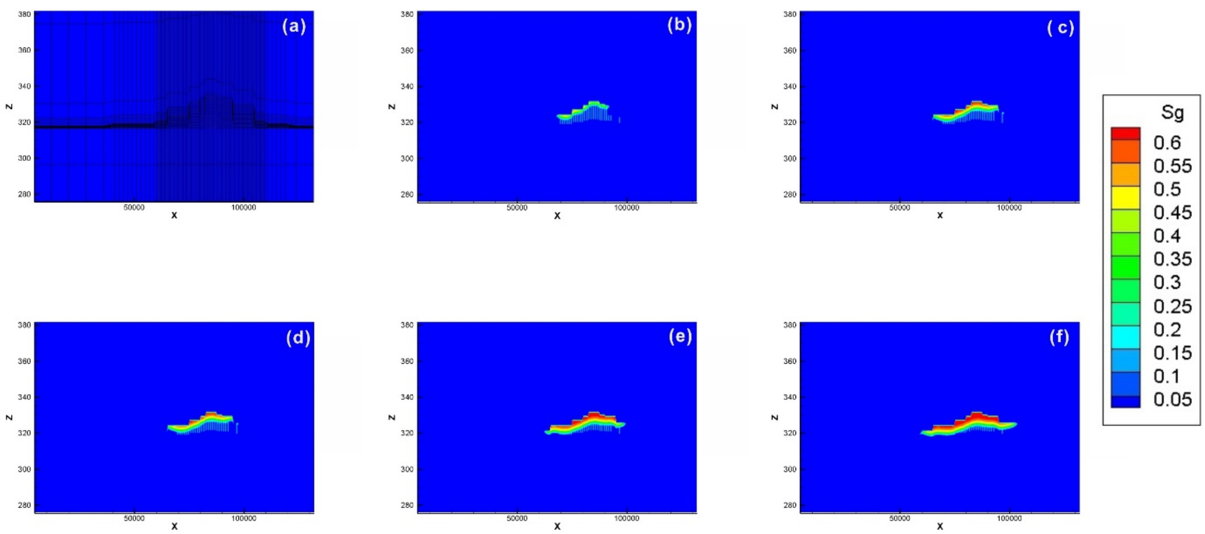

Figure 18 Gas phase is continuously introduced within 275 years' simulation time into Clearwater B Aquifer. The gas phase accumulates near the dome center due to interphase buoyancy

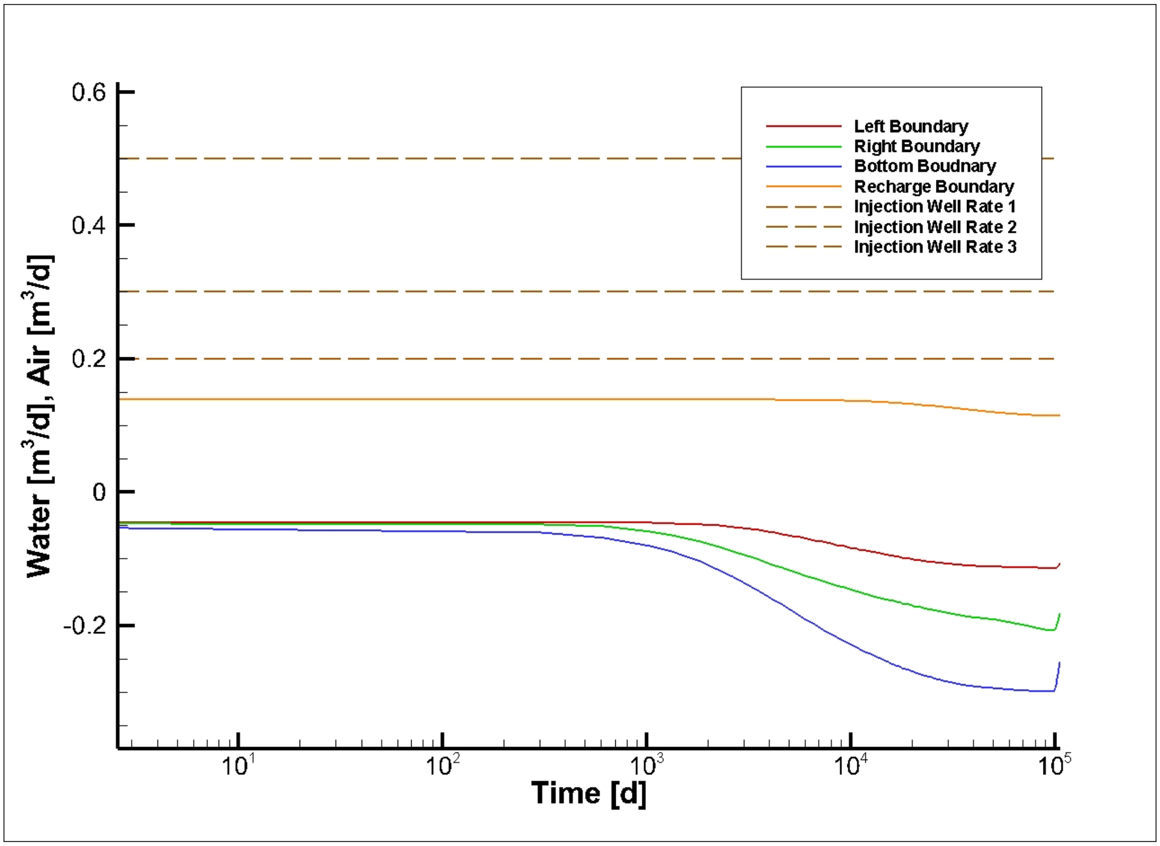

Figure 19 Boundaries reaction and injection well rates under transient-flow simulation

Subsequently, the model re-approaches hydrostatic condition before the pumping stage. Driven by buoyancy and density differences between gas and aqueous phases, the gas phase migrates and redistributes automatically in Clearwater B (Figure 20). Gas aggregates in the top 5m of the Clearwater B. It spreads laterally along top of Clearwater B aquifer, with highest saturation of gas pool accumulate at the boundary between sandy and silty clay layers, reaching as high as 0.7. The capillary barrier and relative permeability barrier between Clearwater B Aquifer and Clearwater Undifferentiated Aquitard work effectively to trap the gas phase below the aquitard unit. Figure 21 demonstrates the boundary reaction recovering to previous steady state condition. It is considered as the critical pre-condition to perform pumping event on gas pool. The assumption that we actually use air instead of methane to represent gas pool should be mentioned. It means exsolution processes are excluded from dual-phase system in CompFlow Bio model.

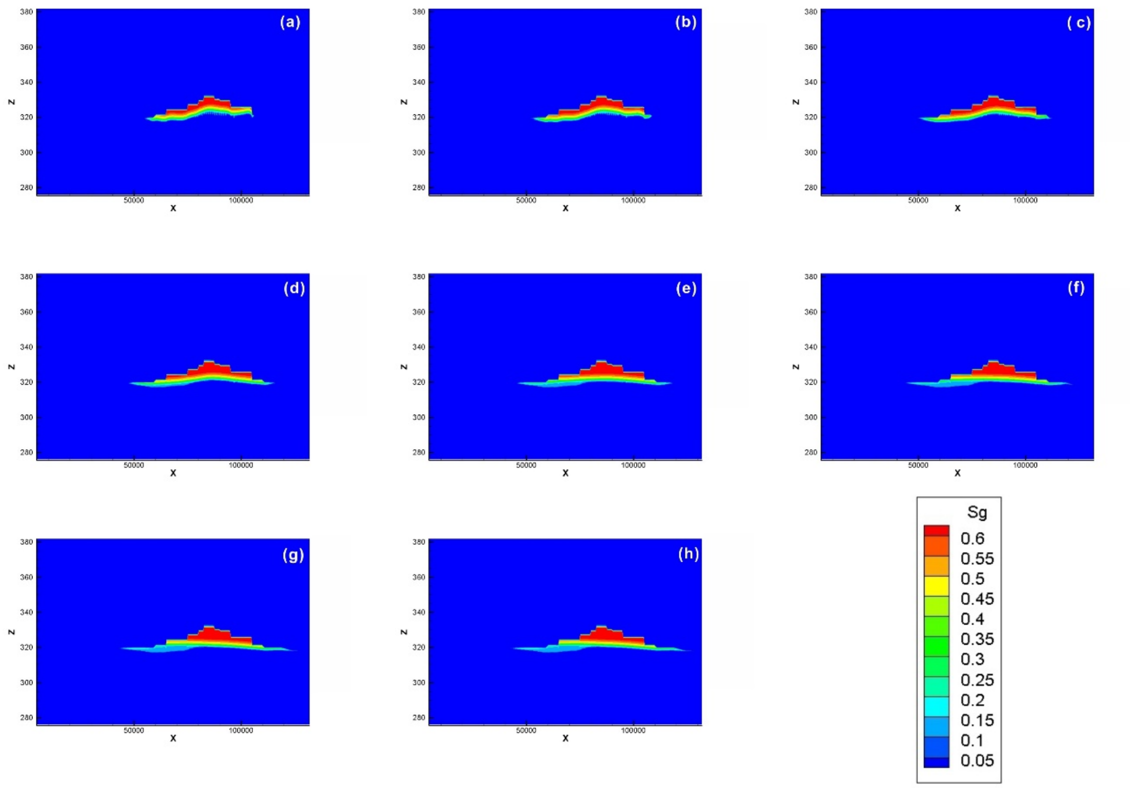

Figure 20 Gas phase redistribution process under ambient infiltration and hydraulic gradient conditions.

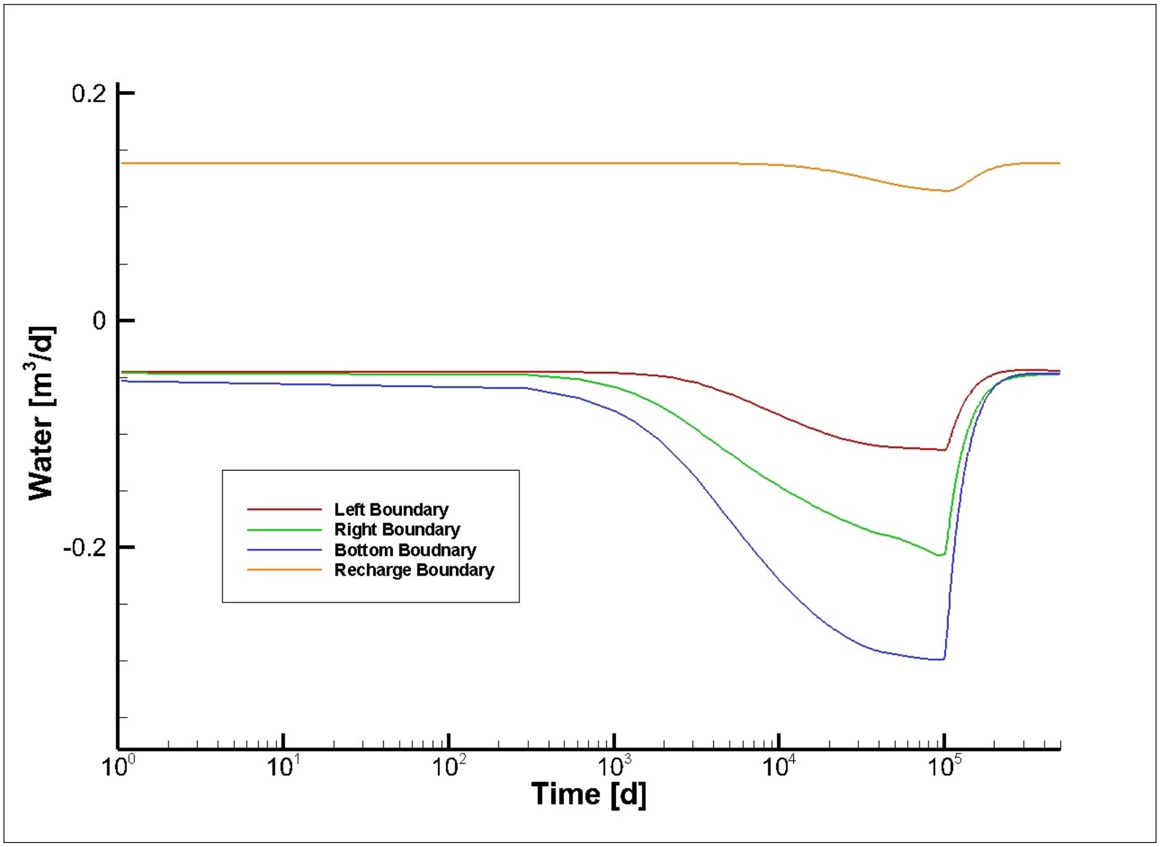

Figure 21 Gas injection stops at 10^5 days. The system re-reaches hydrostatic conditions by 10^6 days.

A 'pressure vent well' is set in the center of gas pool to imitate a gas production well under a pressure-controlled rate. We create the pressure vent within a series of nodes to represent the pumping well screen. Each vent node has a fixed pressure and allows the outflow of material. The difference in phase pressure between the surrounding aquifer and the vent drives the outflow rate, subject to phase mobility. The pressure gradient draws gas escaping through pressure vent. As a conceptual understanding of the gas pumping effects on regional hydraulic head drawdown, the production step is not entirely based on on-site production rates and well assignments. The production rate in simulation is controlled by the pressure gradient. Figure 23 shows the production well performance. Production rates gradually increase until the saturation of gas phase decreases to near residual saturation. For a certain period of time, the vent nodes are assigned with a constant pressure boundary correspondingly, generating a cascade pumping rate preformation. Water invaded into pumping well only at the late stage when this is not enough gas phase driven out under pressure gradient between vent nodes and surrounding aquifer. It can be interpreted as water remains in the gas pocket, and some may invade from the edge and bottom. The following factors contribute to the jagged pumping rate (pink dashed line in Figure 23): The spatial discretization error (node sizes and different node heights) on pressure gradient of gas phase in the reservoir dome; Insufficient feeding of the nodes approaching gas residual saturation. In CF model, non-equilibrium approach sets initial parameters and the results highly matches on-site Clearwater B aquifer pressure observation (Figure 27), especially the trend of available head drop down when close to the main production area. However, local gas production and coexistence water production cannot be reflected exactly in this model. The water production phenomenon reflected in this model might prove that the water migration and pressure change are related to the local gas well production in study area.

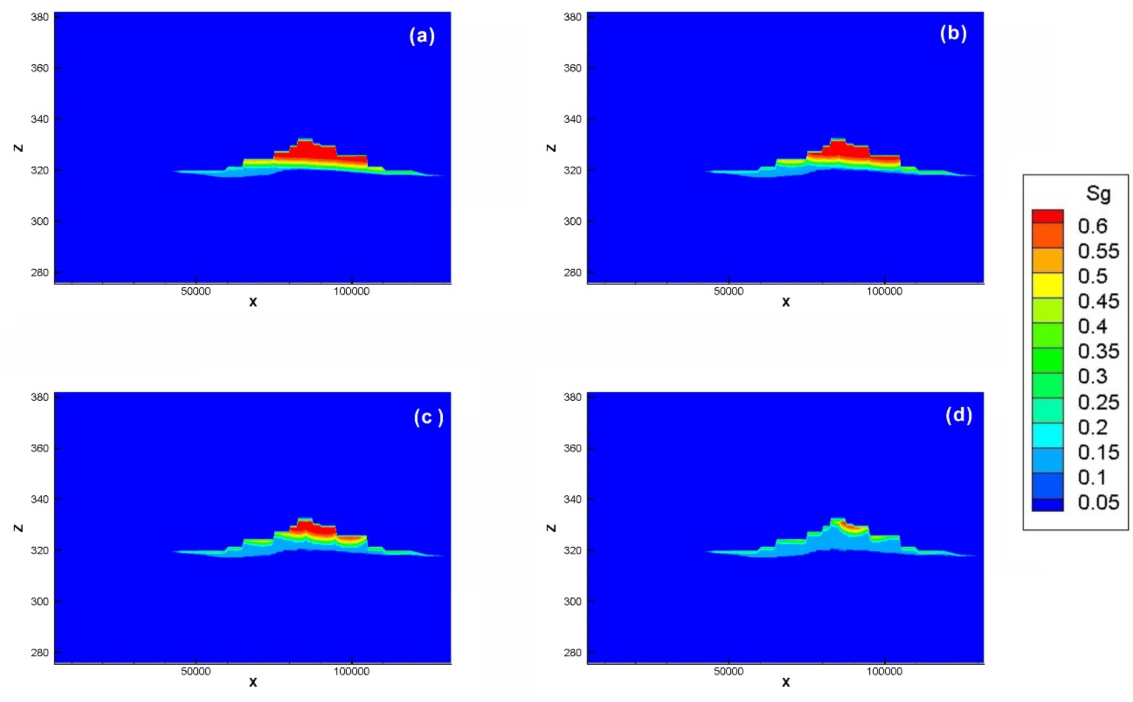

Figure 22 Gas phase is gradually pumped out from reservoir; reduced gas component is reflected by gas saturation decline

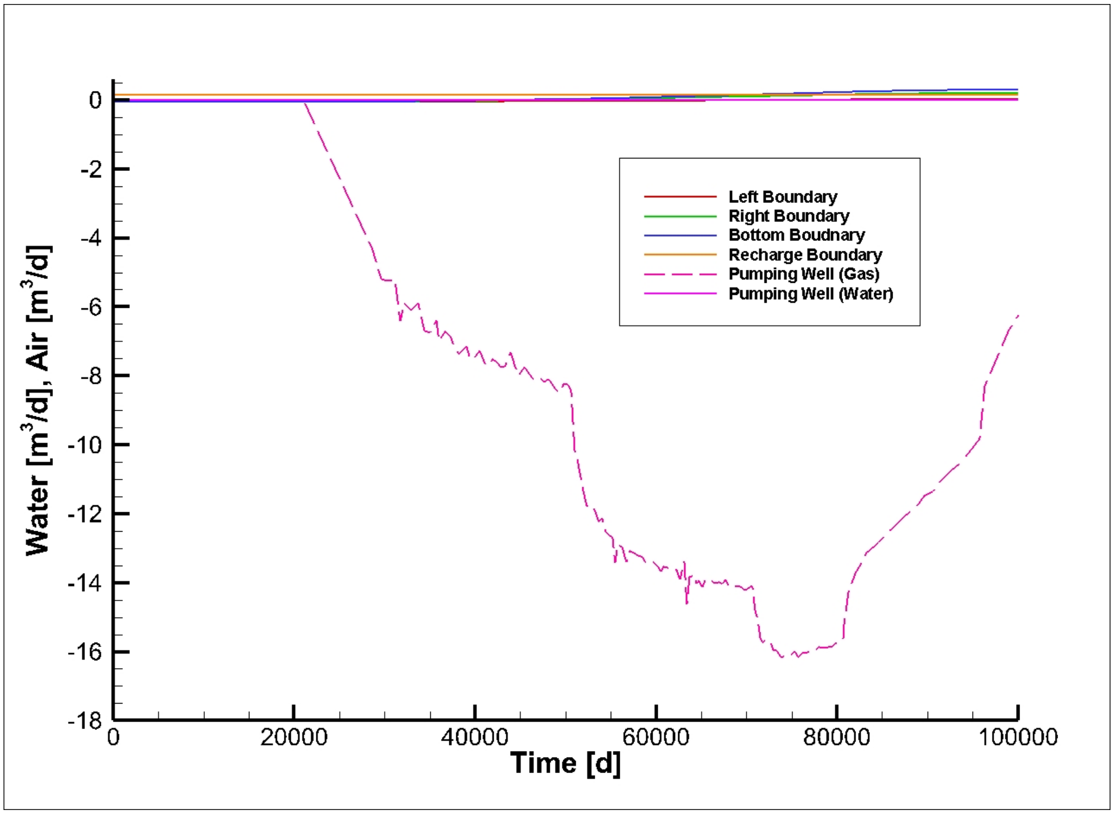

Figure 23 Pumping rate of both gas (dashed pink line) and water phase (solid pink line) through well screen

Another important clue from Figure 24 is the impact of pumping event on recharge boundary. The recharge injection rate slightly increases accompany with gas pumping event. However, the increase is only the order of 0.02 m^3/day, which can be convert to 0.056 mm/year. The annual recharge change under gas production is tiny enough to be neglected. Namely, the result indicates the gas pumping have almost no impact on surface water system. However, the gas pumping process generates significant drawdown in Clearwater B aquifer, as well as overlying formations. The plot in Figure 25 indicates the contour of hydraulic head decline. Head value distinctly depletes accompany with gas production event. The maximum head drawdown reaches 100m from background around production well screen in the main gas pool. As the gas phase initially occupies 70% of pore space on top of dome, it drives a tremendous pressure discrepancy when gas phase begins to be driven out from system. Water invades from bottom and side's boundary. It corresponds with the natural process to compensate pore space, which control by the hydraulic head gradient distribution. There is limitation of recharge event from overlying aquifer due to the low-permeable Clearwater Undifferentiated Aquitard.

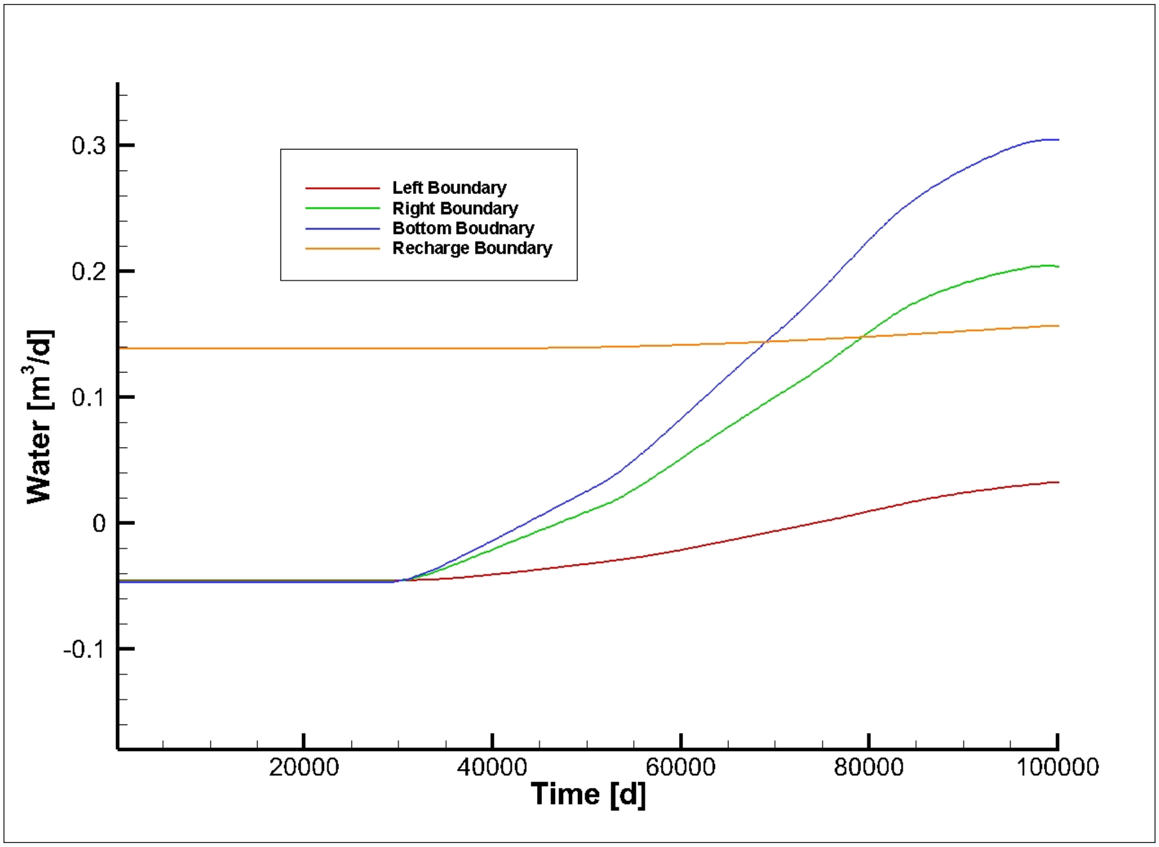

Figure 24 Water invades into aquifer via sides and bottom boundaries

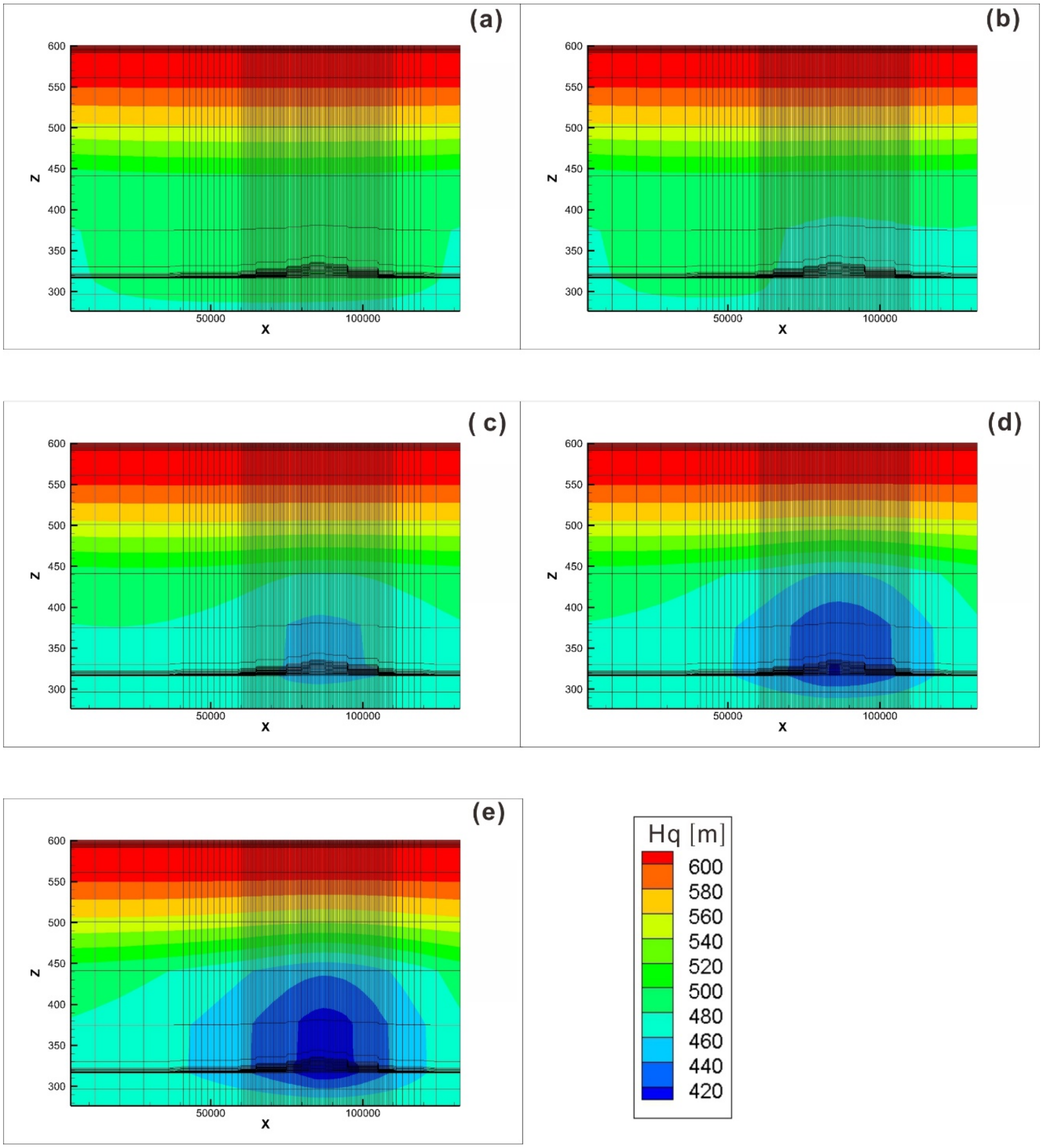

Figure 25 Gas pumping event has great impact on hydraulic head reduction within a large scale

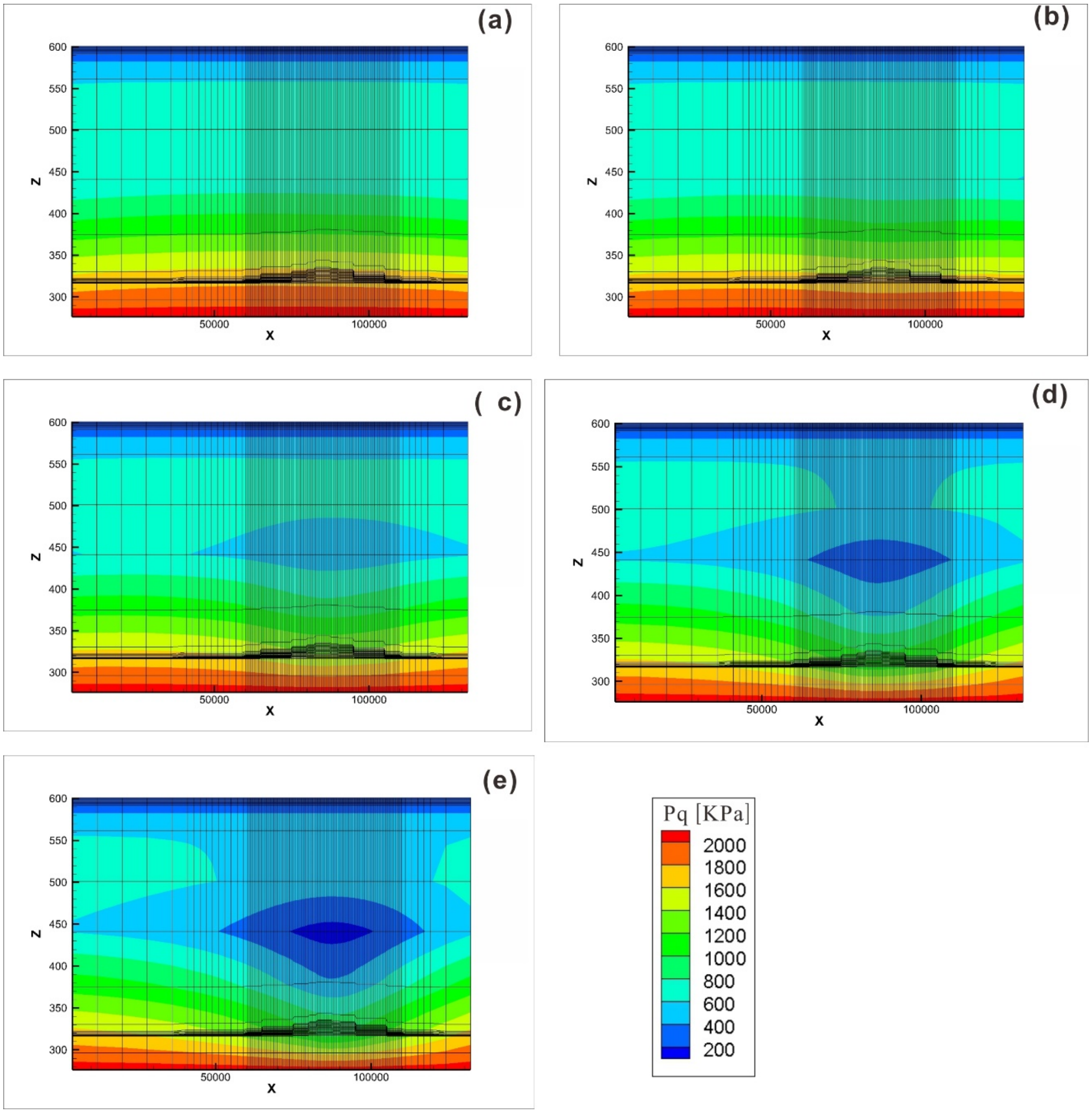

Figure 26 Model domain aqueous phase pressure draw down due to gas phase pumping, including a dramatically low-pressure zone in overlying Grand Rapid Formation.

The conceptual understanding of gas production impact on groundwater system does not involve calibration, because the model structure is not entirely based on precise geology information and gas distribution. In addition, the on-site gas and water production cannot be exactly duplicated into the model. However, a rough comparison between observation and CompFlow model result still can be drawn to a satisfactory on model's performance. Figure 27 compares the Clearwater B aquifer pressure depleting from steady-state condition along the cross section A-A' (crossing the Leismer Lease). The "simulated result" is read from the head value in the nodes at elevation of 320m (the approximate elevation in middle of Clearwater B). The two curves present somewhat consistent with trend and decline magnitude. The south-west of Leismer Lease contains multiple production wells causing provokes more severe drawdown. Only one pumping well in CompFlow model cannot generate equivalent drawdown influence in lateral scale. Thus, on-site water production wells also naturally generate drawdown hollow that cannot be easily differentiated from steady-state background. Nevertheless, CompFlow Bio practice confirms confidence of multi-phase simulation approaches on real groundwater pressure system condition under gas pumping event.

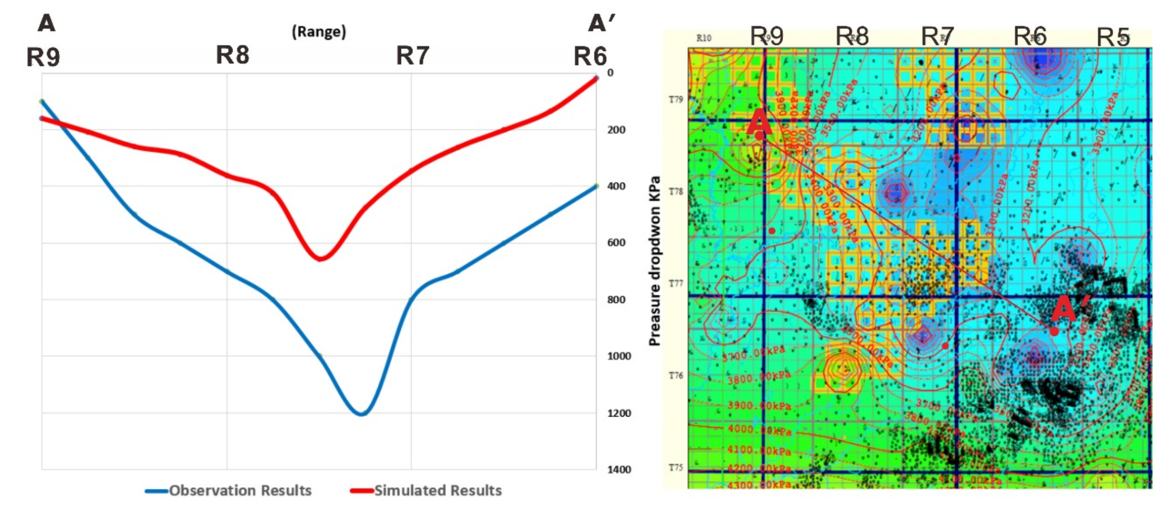

Figure 27 Rough comparison between CompFlow model and on-site observation: Clearwater Formation pressure drawdown from background steady-static pressure condition

Chapter 5

HydroGeoSphere Groundwater Model Results and Limitation

In order to generate comparable results from single-phase simulator candidate HydroGeoSphere, we follow the same setting of model frames, domain discretization, boundary conditions, and similar parameters of each hydrostratigraphic units. Under the similar conceptual framework, single-phase simulation contains two major steps:

1) Steady-state simulation to reach prospective hydraulic condition and compared with CompFlow output results.
2) Transient-flow simulation to modulate hydraulic parameters accompany with pumping water process in order to duplicate the gas production impact on hydraulic head drawdown.

Under the exactly same setting of boundary conditions, domain framework and physical parameters, the present of hydrostatic condition is consistent with multi-phase model (Figure 28). In addition, a water table is present 5 meters under the model surface which can be calibrated with regional observation (Figure 12). From another aspect, it verifies the rationality of geological model and the accuracy of physical parameters for each formation.

A water pumping well is set in the middle of dome, the same well screen location of gas pumping well in CompFlow Bio model. The practice exercise is to examine the attempt to use water well to replicate the drawdown observation. In transient-flow simulation stage, a range of pumping rates, from 100 m^3/day 2400 m^3/day, are examined to try to get anticipated hydraulic head drawdown around the well screen. The Figure 29 presents the hydraulic head contour around well screen with Clearwater B gas pool. After 300 years' simulation time, the domain approaches steady-state flow condition. Even the water well is under an extremely high pumping rate 2400 m^3/day, the cone of depression generated by pumping is only slightly expended due to a combination impacts of water expulsed form storage and the limitation of recharge. As the a relatively high horizontal hydraulic conductivity of Clearwater B Sandy Aquifer, the pumping effects should not be tremendous as water will quickly feed in to drawdown cone to compensate and balance the pressure loss. In another word, it will never be possible to generate a same depression zone as the impact via a gas phase pumping process.

Simply using water pumping well is improbable to generate anticipated aquifer respond. Synthetically considering key parameters controlling aquifer respond under pumping well, hydraulic conductivity (transmissivity) and storativity are considered as potential parameters to adjust with time-step to mimic the component variance through gas pumping process. Ultimately, the current study on HydroGeoSphere is inconclusive. To replicate the multi-phase model results of hydraulic head drawdown along with gas pumping. future investment is still required, which means the regulator's suggestion to use single-phase groundwater model as a reliable tool is yet sealed.

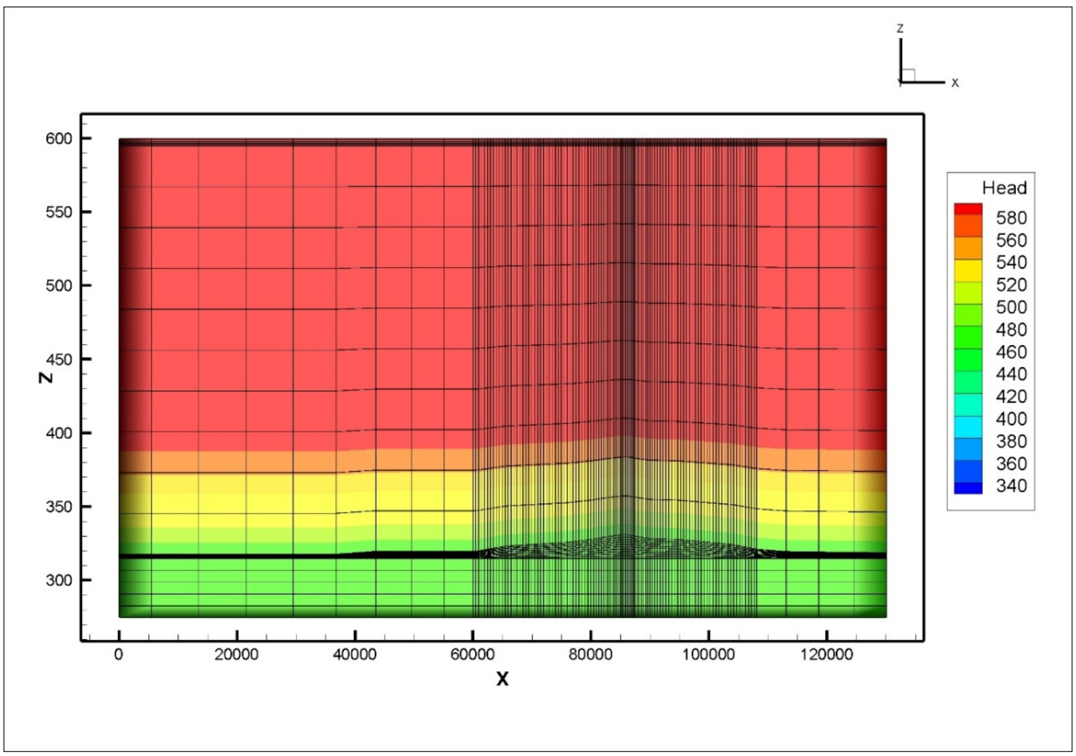

Figure 28 Head contour of hydrostatic condition at the end of steady-state simulation in HydroGeoSphere

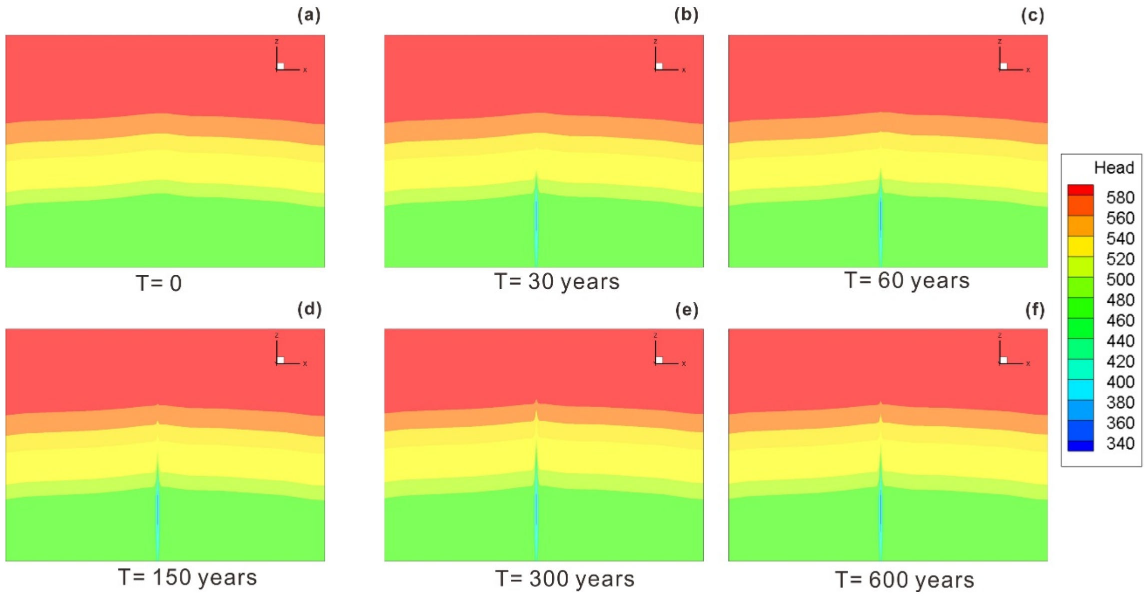

Figure 29 Head contour of drawdown development under constant pumping rate

Chapter 6
Discussion

CompFlow Bio model exemplified and established the phenomenon by a two-phase system model. The study process provides an appropriate physical interpretation and understanding, and simulated results shows perfect consistent with on-site observation of water phase pressure draw down. From a certain angel, multi-phase simulator, such as CompFlow Bio, should be suggested as an efficient tool to deal with similar study cases for operator and regulator. HydroGeoSphere model practice is inconclusive and output shows some limitation on gas production issue. There are numerous points can be driven from the methods and results described above from the case hypothesis, challenges in parameterization, the model outputs and observed limitations of the simulator. In specific, the implication refers to the omission of gas exsolution process, the requirement of laboratory and field data, calibration of historical production event, reconciling model output with sit observation, and computational limits of simulator.

The conceptual model is deigned in 2-D slice, instead of 3-D model. It is due to the study objective as well as computational limitation. Nexen and regulator conducts the hypothesis study on conceptual understating the mechanism and negate methods to replicate multi-phase approaches into single-phase model, no practical application. The magnitude of hydraulic head drawdown generated by gas pumping event might be distinguishable. The gas pocket size, the aquifer thickness and extension in various direction, and the geometry of aquifer and gas pockets in 3-D condition can influence the drawdown discrepancy between 2-D slice model prediction and real observation (comparison shown in Figure 27). From physical aspect, the density difference between fresh water and saline water can also a factor affecting model performance, as mass density might influence the displacement pressure. Nevertheless, the suggestion and discussion is still in secondary consideration. Future study may extend to these details and generate practical function.

Dissolved gas phase in Clearwater Aquifer is common in study site. The original gas source might potentially migrate from underlying McMurray bitumen reservoir or generate through bio-degradation process. The understanding of equilibrium conditions for the co-existing multiphase system is important and critical in this study as it can determine the phase's elimination, new phase formation and the changes of fluid properties (Danesh, 1998). Accompany with gas production, there is abundant gas phase dissolved from water when pressure reduces below a critical bubble point pressure, especially water as a large quantity of existing phase. In CompFlow multiphase model, we assume gas cannot dissolve in water phase, and it means there is no exsolution process during the depressuring process. To provide a more accurate solution and prediction from CompFlow simulation, however, gas exsolution from aqueous phase cannot be neglected since water component is usually abundantly and large gas phase can dissolve in aqueous phase under subsurface pressure and temperature conditions (Li & Nghiem, 1986). Once the pressure is lower than the critical bubble point, the exsolution gas phase from aqueous phase will compensate the pressure loss in some degree and displaces water from storage. Therefore, CompFlow numerical model affirmatively overestimated the pressure draw down. One suggestion of study improvement will be use methane instead of air in CompFlow model scenario and add code to allow phase dissolve and exsolution in multi-phase system.

There are similar multiphase issues that contain same scenario of dissolved gas in groundwater system, such as gas lock issue and coal bed methane production. Particularly, some recently numerical simulation practice from (Maji, Lawrence, & Baxter, 2015) on basal aquifer depressurization and gas lock issue. Represent in single-phase model. In their simulation works via MODFLOW and FEFLOW, the hydraulic conductivity values are revised based on the simulated pressure decline at discrete steps. The automated update of hydraulic conductivity during each time step aquifer pressure and relative permeability. Obtained from k_r-S-P_c relations:

$$K' = (1-p)^{\frac{H-h}{D}} \times K$$

Where:

p : is the percentage of permeability reduction was found for D m of pressure drop

K : Original hydraulic conductivity

h : Hydraulic head in each nodes

H : Bubble point pressure in terms of hydraulic head

Inspired from the work conducted by Maji et al. (2015), we reviewed more basic mathematical solution which describing the dissolved gas issue elaborately. The idea of manipulate the hydraulic value as a function of partial pressure of gas phase in aquifer system should be a solution for single-phase groundwater model to perform and predict gas pumping event in HydroGeoSphere. However, it requires further work on propitiate setting representation of gas phase partial pressure change related with hydraulic conductivity. It is relatively easy to achieve the function in a multi-phase simulator as the partial pressure is directly calculated from k_r-S-P_c relations. In contract, in groundwater mode, HydroGeoSphere, requires more efforts on set up a form of permeability reduction law copying the imitate learn from MODFLOW solution: iteratively stopping the model, exporting the pressure field, calculating the hydraulic conductivity field based on a comparison of the pressure field to the bubble point pressure, importing the revised hydraulic conductivity field back into HydroGeoSphere. There are also other solutions might be considered such as introduce the relationship between the partial pressure $p_g$and the concentration $C_{gl}$of vapor phase dissolved in aqueous phase which can be described as the following equitation (Jarsjö & Destouni, 2000):

$$p_g = HC_{gl}$$

p_g = the absolute gas partial pressure [KPa]

H = Henry's Law constant

C_{gl} = molar concentration of gas dissolved in the liquid

Henry's law is also function of temperature and pressure and it is applied to calculate and predict the gas component in water of reservoir system at low pressure (Danesh, 1998).

Lessons can also draw lessons from Yager and Fountain (2001); (Yager et al., 2001) simulations of effect gas exsolution on specific storage in a confined aquifer system. The work describes the effective specific storage resulting from gas exsolution (S_{Sgt}) as a function of hydraulic head and the dimensionless Henry's Law constant for the gas.

$$S_{sg} = \frac{n}{(h - z + h_{atm})K_h}$$

$$S_s' = S_s + S_{sg}$$

Where:

n: Porosity

h_{atm}: Atmosphere pressure in terms of head [L]

z: Elevation of mid-point of aquifer [L]

K_h: Dimensionless Henry's Law constant

S_s': Effective specific storage [L^{-1}]

S_s: Specific storage [L^{-1}]

Gas exsolution process can be incorporated into HydroGeoSphere as S_{sg} can be calculated for each model cell in each time-step based on the head value in previous time-step. Then effective specific storage can be computed in transient-state simulation. As Yager et al. (2001) obtained positive feedback from MODFLOW and results shows significant dissolved gas impact on aquifer pressures system which decreasing water head drawdown, we should contribution on gas exsolution in both multi-phase and single-phase simulations.

Second, parameters used to set up hydrostratigraphic units and capillary barriers are very crucial to simulation results. Primarily, the complexity of model stratigraphy has been simplified. As we discussed, the physical parameters are directly used from Nexen Long Lake project regional groundwater study. However, the heterogeneity of each formation, especially Clearwater Formation, is strong within large-scale study due to the discontinuity of sandy aquifer (shown in Figure 30). Some practice of parameters sensitivity test should be played in the study. In addition, some local pumping test report, e.g. 10-08-076-08W4 and 11-21-076-08W4 should be reviewed. The conversion of permeability and porosity of Clearwater Formation and Grand Rapid Formation is assumed representing aquifer property more accurate to some extent. These local-scale parameters should be used in a separate scenario as a comparison results.

The parameters used to create k_r-S-P_c relations is also important to simulation result. The distinction of k_r-S-P_c features corresponding with different materials are significant to generate capillary barriers for gas pool. Namely, appropriate k_r-S-P_c of the aiming formation should be accurately obtained following with the suggestion of field and laboratory measurements. The test on the samples from aiming aquifers and aquitards should include entry pressure, residual saturation, pore size distribution index and Corey's parameters of methane and brine. As discussed in the above section, the k_r-S-P_c relation is also particularly essential in single-phase groundwater model if we plan to perform a function of relative permeability as a function of pressure reduction for each time-step.

Finally, calibration is an indispensable section of a model impletion to test model reliability. After model is constructed, assigned with geological and hydrogeological data, and defined boundary condition, model should be calibrated to observed or historical data to establish confidence in predictive ability. However, calibration is not involved in this study due to several limitation and initial study objective. From conceptual understanding view, calibration is unnecessary to perform, especially for a pseudo-3D slides model domain. Besides, historical gas pumping rates and water pumping rates data within Leismer lease is extremely difficult to collect for confidential consideration between operators, which also push transient state calibration difficult to perform in our research stage. The only comment is driven to steady state calibration that is relatively straightforward to achieve. Observed groundwater level of major aquifers can be collected through database of onsite water supply and monitoring wells. Simulated results versus observed heads value can be plotted. The smaller head value differences improve model predictive accuracy.

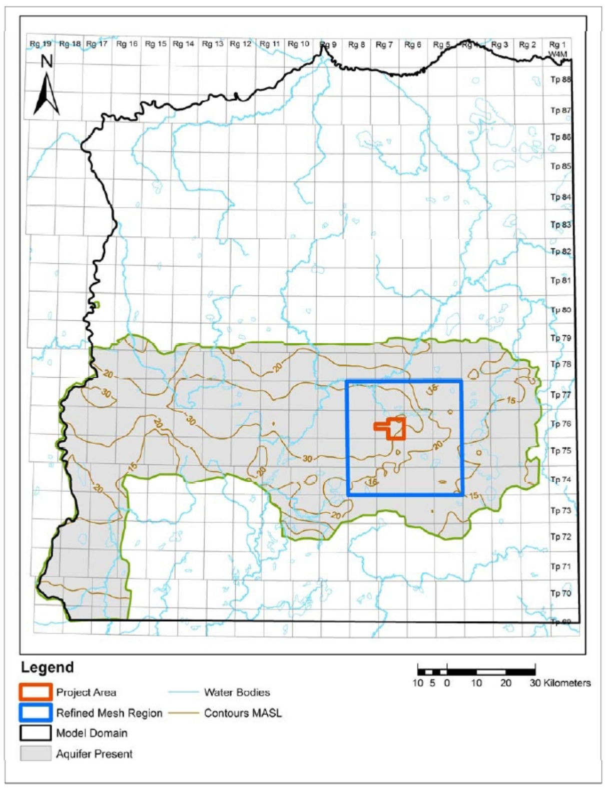

Figure 30 Clearwater B Aquifer Isopach indicating discontinuity of sandy aquifer within study area (Data Sources: Devon Jackfish (2006), EnCana Christina Lake (2009), KNOC)

Chapter 7

Conclusions

In summary, this study uses the CompFlow bio to simulate the aquifer depressurization due to gas phase pumping even, and attempts to use single-phase groundwater model HydroGeoSphere to replicate the hydraulic head drawdown predication. Local geological 2-D model is depicted based on well log interpretation, especially represent the geology of aiming aquifer and main gas pool. Parameterized through calibrated hydrogeological conditions and referenced of rock sample tests, CompFlow Bio simulated results exemplified and presents the phenomenon by a two-phase system model. Simulated gas production captured on-site observation of pressure draw down within Clearwater B and overlying formations. However, the drawdown does not show obvious impact on water table or surface water system. Single-phase model requires further investigation to perform a reasonable prediction involving a hydraulic conductivity variation as a function of partial saturating, or dynamically adjusting specific storage and hydraulic conductivity values on a time-step basis. The results highlight the future efforts on functional improvement on exsolution process in CompFlow Bio as well as experimental and innovative practice on single-phase simulation. To speed up the simulation is significant to apply simulators on 3-D and filed-scale relevant simulations based on computational limitations experiment in this study herein. In addition, further calibration is required to solidify model performance on more rigorous, precisely and practical cases.

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