Modeling of north triumph gas reservoir for carbon-dioxide Sequestration – a case study

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Abstract

Carbon-dioxide is considered one of the major factors for climate change despite its importance for the existence of life on our planet. Apart from several other options, CO₂ can be sequestrated into the depleted petroleum reservoirs to maintain the CO₂-ratio. It can also be used for enhanced recovery due to its solvent-like properties at certain temperatures and pressures. Reservoir modeling plays an important role in evaluating the pros and cons of CO₂ sequestration in a particular reservoir. In this study, we present the preliminary modeling results from North Triumph Gas reservoir for CO₂ sequestration and enhanced recovery.

Keywords: reservoir modeling, history matching, CO₂ sequestration.

1 Introduction

Carbon dioxide is present in the atmosphere and plays a critical role in the photosynthesis reaction that allows plants to grow and its presence is crucial. It also acts as an insulator in our atmosphere so that the global surface temperature remains within a reasonable range. However, it has come to the attention of many scientists that anthropogenic CO₂ may be altering the world’s climate. Carbon dioxide is being emitted constantly at increasingly greater rates around the globe. The modern industrial age is contributing great amounts of CO₂ to our atmosphere on a daily basis.

There are several ways to reduce the concentration of CO₂ in the earth’s atmosphere. The world, as a whole, could burn less fossil fuel or, the CO₂ that is produced could be captured and stored for long term, or at least until the fossil fuel based economy becomes less significant.
It is possible to capture CO$_2$ and store it in locations such as the ocean, coal seams, saline aquifers or oil and gas fields. Each of these sequestration methods has associated advantages and disadvantages.

This paper models a depleted gas field offshore of Nova Scotia for CO$_2$ sequestration and for enhanced natural gas recovery. For modeling, the geological and petrophysical information available from the Canada Nova Scotia Offshore Petroleum Board (CNSOPB) is reviewed. This information includes the Development Application Plan (DPA) for the field, well logs, geological descriptions, well test reports and historical production data. From this information, a full field scale simulation grid was constructed and initialized honoring the geometry and petrophysical properties of the subject gas field. The simulation model was also initialized with an updated value of initial gas in place, calculated with a material balance equation based on actual production data. Once the model was constructed and initialized, the simulation was run and history matched to finalize the model.

2 Related works

As mentioned earlier, several CO$_2$ sequestration methods exist, including biomass storage, deep ocean storage, and geological storage.

Biomass sequestration utilizes the photosynthetic process used by plants. It is estimated that a total of 700 million hectares of land might be available globally that could sequester between 220-320 Gt CO$_2$ (Houghton et al [1]). This represents only about 11 -16% of the CO$_2$ emissions expected till the year 2050 (Davison et al [2]).

Another potential option for storage of CO$_2$ at deep ocean depths may lower the pH level of water. Increased biological production of organisms that take up carbon dioxide may offset the CO$_2$ storage too, according to Ormerod et al [3]. It is also unclear how CO$_2$ would affect marine life and under current international law, it is illegal to dispose of CO$_2$ in the ocean (Gale [4]).

There are three main options available for subsurface CO$_2$ sequestration, namely saline aquifers, unminable coal seams and existing oil and gas fields. Of these three options, injection into existing oil and gas fields or unminable coal seams have the potential to be economically feasible due to the possibility of enhanced oil and gas recovery [4].

There are several advantages to injecting CO$_2$ into an oil or gas reservoir, namely, increase in sweep efficiency and incremental recovery, more storage of CO$_2$ compared to saline aquifers (Chadwick et al [5]) and proven ability to store oil and gas for geological period of time.

However, existing literature for CO$_2$ sequestration in depleted natural gas reservoir is very limited, especially when we consider enhanced recovery as well. Van der Burgt et al [6] were primarily interested in disposing of CO$_2$ in a depleted gas field. Although the authors did note that additional natural gas might be recovered due to their scheme, the primary focus of the study was to study the viability of an abandoned gas field as a disposal option for the produced CO$_2$. 
Oldenburg et al [7] were concerned with the physical process of injecting CO$_2$ into a depleted gas field. The authors concluded that incremental natural gas could be recovered both during and after the injection of CO$_2$. Oldenburg and Benson [8] used finite difference method to model the same Rio Vista gas field. The authors constructed a two dimensional model with one injector and one recovery well, where pressure and breakthrough time were reported for the wells and various grid blocks. The authors also constructed a three dimensional, 5-spot, model and again pressure and breakthrough time were reported for the wells and various grid blocks. This study was concerned only with the injection of pure CO$_2$.

Sinisha et al [9] investigated enhanced gas recovery through carbon dioxide sequestration. The authors modeled two different injection strategies of carbon dioxide into a natural gas field. Based on the study, the researchers concluded that the highest recovery of natural gas can be achieved by injecting CO$_2$ once the field has reached its economic limit. However, no effort was made to optimize the storage of the CO$_2$.

It can be seen that the injection of CO$_2$ into depleted gas fields can both lead to incremental recovery of natural gas as well as the sequestration of carbon. In this paper, the modeling part of our study is discussed and the results for various options for gas recovery and carbon dioxide sequestration processes will be presented in the conference.

3 Reservoir data

The North Triumph reservoir is a rollover anticline that is bounded by major listric faults and divided by minor en echelon faults. The gas is trapped in a single pool of a gas column of 171 meters from the top of the anticline down to the gas water contact. Log correlation between wells completed in the North Triumph field is good, as is pressure communication, indicating stratigraphic continuity over most, or all, of the structure ExxonMobil DPA [10].

The North Triumph field is at a depth of 3,640 m subsea, and extends over an area of 19 square kilometers. A total of two exploratory wells, B-52 and G-43, were completed in the North Triumph field. Average porosity, water saturation and permeability values for the B-52 and G-43 wells are 0.18 and 0.20, 0.36 and 0.15, and 60 mD and 70-100 mD, respectively.

A total of two production wells, NT-1 and NT-2, were also drilled and logged as part of the field development. These logs include information on porosity, water and gas saturation, density, permeability, and perforations. Two layers out of eight layers exhibit a very low permeability (0.1mD), porosity (0.01) and zero gas saturation and are likely shale layers. In the sandstone layers however, the permeability ranged from 1 to 300 mD, the porosity ranged from 0.10 to 0.20, and the gas saturation ranged from 0.5 to 0.80. It is to be noted that the values within a layer are consistent but not homogeneous.

The field is bounded by normal faults to the northeast and south. These faults are a barrier to flow as no gas has been interpreted to be present on the opposite side or the faults, even where juxtaposed with sandstone [10]. Also, two en
echelon faults are present in the southern portion of the gas field. The en echelon faults bisect the gas field vertically, but terminate within the reservoir laterally.

The reported temperature gradient for the North Triumph field is 32 degrees Celsius per 1000 meters [10]. This is approximately consistent with the temperature gradient for other fields in the Sable Sub-basin.

The field is hydrostatically pressured and the initial free water level was 3771 meters subsea. No water drive is present in this gas field.

The PVT properties for the reservoir rock, water and gas are presented in two well test reports and included below in Table 1. This information is used for our simulation model.

### Table 1: Select PVT properties for the North Triumph Reservoir from well test reports

<table>
<thead>
<tr>
<th>Well ID</th>
<th>Formation Compressibility (kPa⁻¹)</th>
<th>Init. Gas Viscosity (µPa.S)</th>
<th>Init. Gas FVF (m³/m³)</th>
<th>Init Water Viscosity (mPa.S)</th>
<th>Water Compressibility (kPa⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NT1</td>
<td>5.8176E-07</td>
<td>25.2416</td>
<td>3.8033E-03</td>
<td>0.22876</td>
<td>4.2535E-07</td>
</tr>
<tr>
<td>NT2</td>
<td>5.9273E-07</td>
<td>24.7124</td>
<td>3.8306E-03</td>
<td>0.23186</td>
<td>4.1917E-07</td>
</tr>
</tbody>
</table>

Results of special core analysis were not available for review during this study. As a result, the actual laboratory determined relative permeability and capillary pressure curves were not available for input. However, the endpoint relative permeabilities were provided by a representative from the field operator, ExxonMobil Canada Ltd., and these endpoints are listed below:

\[
S_{wc} = 0.35, \quad K_{rw} = 0; \quad S_{wmax} = 0.75, \quad K_{rw} = 0.05; \quad S_{gmin} = 0.35, \quad K_{rg} = 0; \\
S_{gmax} = 0.65, \quad K_{rg} = 0.95
\]

The production history for the field is publicly available from the CNSPOB and is used to validate the simulation model through history matching.

For North Triumph gas field the mean initial OGIP (Original Gas in Place) was estimated to be 15.2 E9 m³ with 72% recovery factor. However, based on the actual production data collected from the CNSOPB, only 5.46 E9 m³ of natural gas was produced from the field. It seems clear then, that the initial evaluation and calculations did not capture the true nature of the gas reservoir.

The production data was used to calculate a new value for OGIP using material balance equation from Garb and Smith [11]. The calculated value for OGIP is 10.3 E9 m³. The simulation grid was constructed such that the OGIP was equivalent to the new calculated value.

### 4 Simulation model

The model was constructed using Petrel® and Eclipse® software provided by Schlumberger Canada. Eclipse E100, also known as the Eclipse black oil simulator, is a finite difference simulator that allows the user to specify the
phases present in the model, and also has various add-ons available, such as the hysteresis and solvent options. This model assumes isothermal conditions and does not incorporate various components of each phase. The simulator is based on two governing equations, Darcy’s Law and the Material Balance Equation.

The Eclipse simulator solves a combination of Darcy’s Law and the Material Balance Equation for each grid block and for each time step. Eclipse allows the user to select implicit or explicit solution method and to determine the maximum time step size. For the current simulation problem, the fully implicit solution method was chosen and time steps ranged in size from many days to a few minutes depending on the complexity of the problem.

The grid was built using the Petrel software package. The geometry of the grid was based on figures presented in the DPA. The same surface was then used to define the top and bottom of each of the eight layers. Faults were also input into the model. The boundaries of the model are defined by faults to the north, northeast and south. Also, two smaller en echelon faults are present in the southern portion of the field. The faults are believed to be sealing, so the faults are modeled as no flow barriers.

Sensitivity analysis was completed using Petrel to determine an appropriate grid size for the simulation. The final grid size was established as being 58 by 30, and 8 layers thick. This represents a total of 13,920 grid cells.

Corner point geometry was used as in Eclipse, this allows for non-neighbor connections (NNC) to exist without being specified by the user. This is important when there is displacement and communication across a fault. Also, the corner point geometry allows for more realistic grids to be created, with smooth surfaces, as opposed to block-centered grids.

In our model, two shale layers were modeled as inactive layers, with a limited number of active cells to allow pressure communication between the layers. It helps the model to run faster while maintaining pressure communication between layers opposite to the shale layers. The layers were initialized with petrophysical properties obtained from well logs but were varied to a small degree within specific layers. This was done to represent the heterogeneity in the actual reservoir rocks.

This particular model has three phases, gas, oil and water. Even though the field is a dry gas field, a three-phase model was chosen so that the solvent model option could be used for CO$_2$ sequestration. Various PVT and SCAL data was entered into the model. However, the exact relative permeability and capillary pressure curves were not known and is dealt differently.

The production history of the field was also entered into the model. The production history covered the time period from December 1999 to May 2006.

The production wells were defined within Eclipse. Both production wells are vertical wells. These wells were placed in the grid according to coordinates that were provided in end of well reports.

Both production wells were placed in local grid refinements. These grid refinements were defined in Eclipse and are radial in nature. The radial grid refinement option was chosen, as opposed to the Cartesian grid refinement, as the radial option allowed for the model to run more efficiently.
5 Results

Once the model was developed and populated with relevant data, the model was run. Figure 1 shows the initial gas saturation for the model in December 1999. The free water level was set at –3771 meters, subsea, as presented in the DPA.

The history match was achieved by adjusting the relative permeability curve, capillary pressure curves and the net to gross ratio (NTG). Various laboratory-determined data including porosity, compressibility and saturations were honored for the modeling purpose.

The NTG was adjusted such that the correct OGIP would be predicted by the model. The representative from Exxon stated that the model saturations, porosities and gas-water contact looked reasonable, therefore, to achieve the correct OGIP, the NTG needed to be adjusted downward.

As the actual relative permeability curves and capillary pressure curves were not known, the default curves available from the Petrel software package were used first and then based on the end-point permeability values these curves were adjusted gradually to achieve an acceptable history match.

In Figure 2, the historical water production rate and predicted water production rate for well NT1 is shown. It can be seen that the trends for the peaks and troughs do generally match. However, there is some discrepancy that is likely caused by the model not successfully capturing the finer details of the actual reservoir geology. Things such as high permeability channel deposits or localized low permeability shale breaks were not accommodated by the simulation model and it is possible for these zones of high or low permeability to affect water production rates due to variations in associated capillary pressures.

Figure 1: Initial gas saturation for the North Triumph Simulation Model, layer 1 (December 1999).
Water production at the other well, cumulative water production and bottom-hole pressure were also used for history matching and were found to be reasonably close to the actual production data.

6 Conclusions

In this study, modeling of North Triumph Gas reservoir is carried out successfully using limited data available. Laboratory tested data, like porosity, were honored and the heterogeneity of natural reservoir was also taken into account. The model was then validated through history matching with the actual production data. For the unavailable dataset, the standard curves were modified honoring the end points from the partially available data to fit the history match trend.

The results from the modeling study for various options related to gas recovery and carbon dioxide sequestration processes will be presented in the conference.

References


