WELL PERFORMANCE DIAGNOSTICS AND FORECASTING USING THE GUDRUN WELLBORE SIMULATOR - CASE STUDIES FROM KAWERAU, NEW ZEALAND

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ABSTRACT

Ngati Tūwharetoa Geothermal Assets Ltd. (NTGA) relies on real-time wellhead data trends and periodic downhole wellbore surveys to understand and forecast geothermal fluid supply availability and reinjection capacity. This paper illustrates the use of Gudrun, the standalone wellbore simulator application of the Volsung geothermal reservoir simulation software package. Here we have applied Gudrun for well performance diagnostics and are using it for forecasting future well performance based on future reservoir conditions.

Wellbore models were developed for a production and an injection well from the Kawerau Geothermal Field, calibrated with wellbore data and history-matched with continuous wellhead data to determine model performance. The calibrated wellbore models were used to forecast well performance using expected reservoir and wellhead conditions. The wellbore model forecasts provide insight into well performance and reservoir changes and are useful proxies for field performance forecasting while developing a full-field numerical reservoir model. Ongoing investigation is also carried out to determine whether mismatches between the wellbore model forecast and actual wellhead performance could be used as basis for optimising the wellbore downhole monitoring program.

1. WELL PERFORMANCE DIAGNOSTICS AND FORECASTING

Successful reservoir surveillance and monitoring requires effective well performance diagnostics to characterise and anticipate the predicted changes in well performance with changing thermodynamic conditions in the reservoir.

At Ngati Tuwharetoa Geothermal Assets Ltd, we have been building our in-house capability to operate, maintain and manage our geothermal field assets. This process involves the review and update of our wellbore models to ensure that the estimated field capacity is reliable and to improve our team's ability to understand and respond to well performance changes and/or variations to forecast.

We correlate all available well information to build a conceptual understanding of how the well behaves and how it interacts with the reservoir. Well information comes from continuous wellhead and separator data, periodic tracer flow test (TFT) mass flow and enthalpy data, geochemical trends, and downhole measurements.

Ideally, this conceptual understanding guides the building and calibration of wellbore simulations for each well, which is then used to infer and forecast well performance.

Without calibrated wellbore simulation models, well performance is estimated using output curves (flow and enthalpy versus wellhead pressure) built from fitting curves to continuous production data, flow performance tests or TFT data.

1.1 Wellbore simulation models

Wellbore simulation models are numerical simulations that describe the physics and thermodynamics of geothermal fluid flow in geothermal wells. Different geothermal wellbore modelling computer programs have been developed over time, evolving as computing technology improves and new two-phase pressure drop correlations became available.

Wellbore simulation models are important tools in geothermal field operations and reservoir management. Wellbore models have been effectively used at different stages of geothermal field development including the design of wells and surface facilities, evaluation of downhole tubing installations, estimating well performance at different operating conditions, characterising and diagnosing well performance issues, and informing well intervention design and programs to name a few.

One area of wellbore simulation application that we would like to explore is using mobility-corrected feed zones for well diagnostics and forecasting future well performance.

1.2 Forecasting

Forecasting well performance at NTGA is currently carried out using classic decline curve analysis techniques, assuming a normalised operating condition to forecast future well capacity. This approach to forecasting assumes that the reservoir and operating conditions present during the decline curve analysis (DCA) will remain the same for the forecast period. Each well performance is represented by a decline curve equation of its mass flow or enthalpy, as a function of time.

A more sophisticated forecasting technique would use the full-field numerical reservoir model, fully coupled with wellbore simulation models such as those that can be built using Volsung (Clearwater and Franz, 2019; Franz et. al., 2019). Fully integrated numerical reservoir models provide a robust forecast based on the predicted evolution of the modelled geothermal reservoir and the expected output from wellbore simulations.

However, not all operators have ready access to a well-calibrated and fully coupled reservoir simulation model.

The forecasting framework in this paper could fill the gap between those based on classic decline curve analysis and those using a fully-coupled numerical reservoir model.

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2. GUDRUN WELLBORE SIMULATOR

Gudrun is the standalone wellbore simulator application of the Volsung geothermal software package (Clearwater and Franz, 2019; Franz et. al., 2019). A graphical user interface is provided which enables the modeler to comfortably set up new simulations and calibrate the model using field data. Gudrun can also be run in command-line mode which is useful for automated batch-mode processing and inverse modelling purposes.

The wellbore simulator is based on the conservation of mass, energy and momentum for steady-flow situations. The governing equations can be found elsewhere (e.g. Hasan&Kabir 2002). The equations for the pressure and enthalpy gradients form a system of ordinary differential equations which can be numerically solved using either a simple Euler or a 4th order Runge-Kutta method. A wide range of pressure drop correlations are included, e.g. homogeneous, Hasan & Kabir (2009, 2010), Duns & Ros (1963), Hagedorn & Brown (1965), Hadgu (1989), and others.

Wellhead characteristic curves for both production and injection problems can be generated and make use of advanced search algorithms (Franz, 2015). These search algorithms are very robust and hence allow the simulator to be run in fully automated modes without user intervention over a wide array of thermodynamic conditions.

A particular feature used here is the ability to set up wellbore simulation models using feed zones corrected for mobility. This enables us to explore the possibility of forecasting well performance with changing reservoir conditions. The linear case of the simplified Darcy-Forchheimer is

$$w = \Upsilon \cdot kh \cdot (p_r - p_w)$$

with the mass rate w, constant permeability-height product (kh) and reservoir and wellbore pressures p_r and p_w, respectively. Υ is the mobility term and depends on the changing thermodynamic conditions of the reservoir.

Once we have a calibrated wellbore simulation model using mobility-corrected feed zones, we can use the wellbore simulation models to forecast well performance at different operating conditions and predicted reservoir conditions.

In addition, we could potentially optimize our future well monitoring programs and improve reservoir management outcomes.

3. FRAMEWORK FOR USING WELLBORE SIMULATION IN WELL DIAGNOSTICS AND FORECASTING

The framework presented in this paper follows the standard framework for developing, calibrating and using the geothermal numerical simulations for reservoir studies and forecasting future performance as applied to wellbore simulations.

The idea for extending the use of multiple wellbore simulations calibrated with reservoir trends and historical production data is based on the process described by other authors using an in-house software application (Libert and Passiki, 2010; Libert and Alvarez, 2015).

We tested the capability of Gudrun to perform the same routine to generate simulation-based forecasts, enabled by Gudrun's ability to be automated using Python scripts as shown in Figure 1. In addition, this paper also attempts to further advance the use of the wellbore simulation models in evaluating well performance issues that could potentially inform our resource management options.

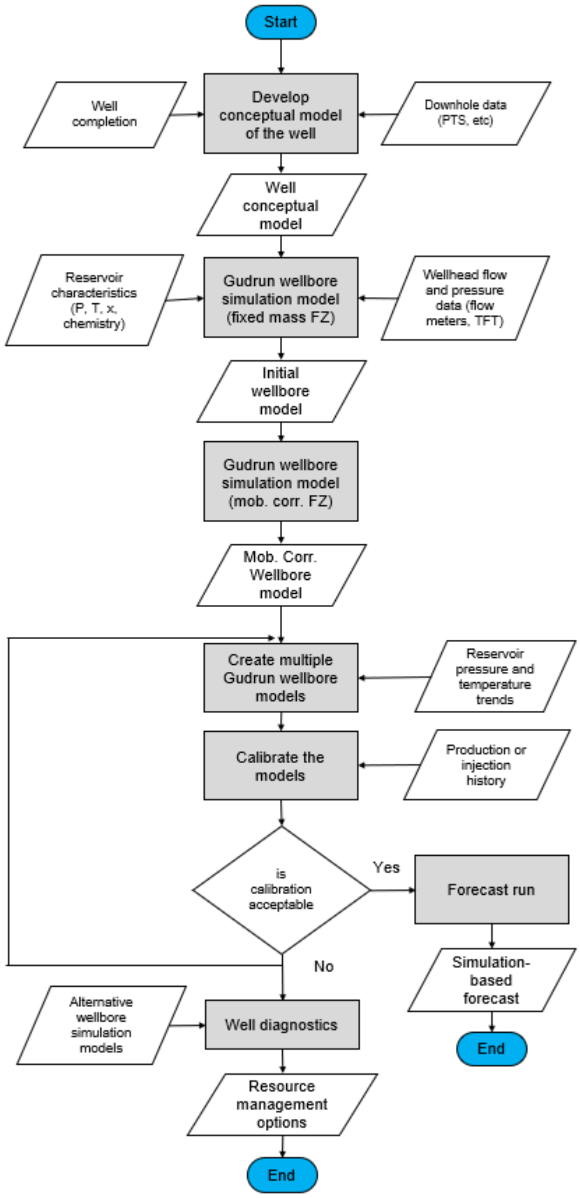

Figure 1. Framework for wellbore simulation in well diagnostics and forecasting.

Details of the framework implemented in the case studies are described as follows:

1. Develop the conceptual model of the well using all available well and reservoir information. This usually involves integrating available well drilling and completion information together with all available downhole PTS surveys. The conceptual model would describe the geometry of the well, the initial feed zone characteristics, and initial understanding of the effective reservoir conditions. These would all be required inputs into the Gudrun wellbore simulation.

2. Build the Gudrun wellbore simulation model using the following inputs:

- Well track/well deviation
- Well casing completion
- Feed zone depth/elevation
- Reservoir pressure and temperature profiles

3. Calibrate the wellbore model with the analysed PTS by using the “fixed” type feed zone and assigning individual feed zone mass flows. Run an “upward” simulation type integrating from the deepest feedzone up to the well head. Choose the best pressure-drop correlation that matches the PTS pressure profile. This is the initial wellbore model.

4. In Gudrun, copy the mobility-corrected feed zone permeability at the results tab of the initial wellbore model under “lin. simp. kh,” in m^3 units, then convert the wellbore model feed zone type in the inputs from “fixed” to “simplified Darcy-Forcheimer” and copy the mobility-corrected feed zone permeability (kh) into the feed zone inputs.

5. Rerun the wellbore simulation but edit the simulation type to “DC Wellhead Pressure Search” to establish a deliverability curve (DC) or output curve (mass flow and enthalpy versus wellhead pressure curves) and generate a simulation of the wellbore pressure, temperature and velocity profile at the wellhead pressure of the analysed PTS used for calibration in Step 3.

6. If required, recalibrate the wellbore model output curve with available measured wellhead output curves or wellhead TFT data. Once calibrated, this is now the “mobility-corrected wellbore model” to be used in the production history calibration.

7. Establish the reservoir conditions over the production history period, i.e. reservoir pressure and temperature/enthalpy trends.

8. Generate and run multiple versions of the wellbore simulation model using the reservoir trends and calibrate the results with the production history. This may require adjusting the mobility-corrected feed zone permeability until a satisfactory history match is achieved.

9. If calibration with production history is satisfactory, run the wellbore simulation in forecast mode using future prediction of reservoir trends and establish the well performance going forward. This is now the “simulation-based forecast” of the well’s performance.

10. If calibration with production history is unsatisfactory or the calibration match deviates over time, develop and run alternative wellbore simulation models to diagnose and understand the change in well performance.

11. Once well diagnostics is complete, recommend “resource management options,” if any.

Examples of this framework applied to two NTGA wells from the Kawerau Geothermal Field are discussed in the next section.

3. CASE STUDIES

3.1 Production Well A

Well A is a production well that was observed to decline in enthalpy and mass flow over a three-year period. The well is currently stable but is a marginal producer.

This case study aims to confirm whether the framework could retroactively model the changes to the well performance, identify areas of improving reservoir surveillance/monitoring, and establish a simulation-based forecast or resource management options for the well.

3.1.1 Well A - Conceptual Model

Well A is a directional well completed with a 9 5/8” ID production casing set at 512m CHF (casing head flange reference). It has a 6 5/8” ID perforated liner inside an 8 ½” ID borehole with the top of the liner at 495 m CHF down to total depth at 1214 m CHF.

Initial production characteristics based on wellhead TFT data and flowing PTS surveys indicate a strong producer with capacity to produce around 500 t/h mass flow at a discharge enthalpy of 1200 kJ/kg. Over the three-year period, this has declined to a mass flow capacity of less than 300 t/h and a discharge enthalpy of around 940-950 kJ/kg.

Well A has multiple feed zones tapping the shallower production zone of the Kawerau geothermal reservoir. Initial reservoir temperatures at the feed zones were around 270-275°C, declining to and stabilising at around 220°C. The reservoir pressure had a modest initial decline of around 0.15 bar/yr followed by an increasing pressure trend.

Geochemistry indicates increased rate of mixing with marginal recharge as the main reservoir process. This marginal recharge is a lower temperature and more dilute recharge fluid, likely meteoric recharge mixing with in situ geothermal fluid to around 210-220°C. The reservoir fluid also has the potential to deposit calcite in the wellbore so a downhole anti-scalant system was installed.

3.1.2 Well A - Wellbore Model

The Well A wellbore model was built in Gudrun using the initial well and reservoir conditions as described in the conceptual model above. Results of the “Upward” wellbore simulation using fixed mass feed zone type are shown below. This Gudrun simulation matches the well pressure and temperature profiles using a Duns and Ros pressure-drop correlation and initial reservoir condition.

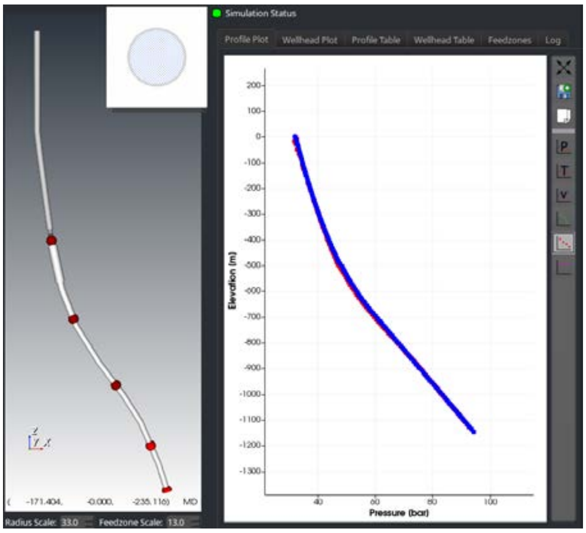

Figure 2. Well A Gudrun simulation - pressure profile calibration

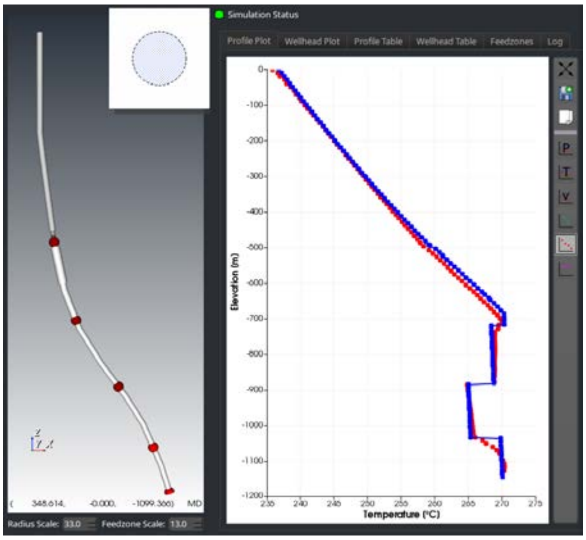

Figure 3. Well A Gudrun simulation - temperature profile calibration

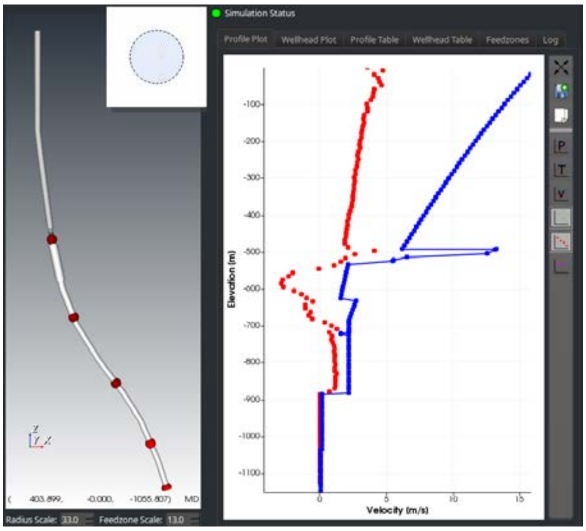

Figure 4. Well A Gudrun simulation - velocity profile calibration

The simulated fluid velocity profile in Figure 4 above indicates a mismatch between the simulation and the analysed spinner data. There is also a noticeable wellbore enlargement at around 550-700 m CHF. However, the fixed mass flow feed zones indicate that this simulated fluid velocity is required to match the wellhead mass flow. Either the analysed spinner data or the input wellbore flow geometry is incorrect, or the wellhead mass flow data is incorrect. For this case study, we will prioritise the TFT mass flow data as this was measured a day after the flowing PTS survey and will be used in the production history calibration.

The mobility-corrected feed zone permeability values are shown in Table 1. The feed zone input of the Gudrun simulation was updated with these values and a “DC Wellhead Pressure Search” simulation was carried out. The output curve matched with the wellhead TFT mass flow is shown in Figure 5.

This “mobility-corrected wellbore model” was used as the base model for production history calibration.

Table 1. Well A mobility-corrected FZ permeability

FZ elevation [m]	kh [m^3]
-523	8.36E-12
-718	8.21E-12
-883	1.81E-11
-1034	8.36E-13
-1147	1.52E-13

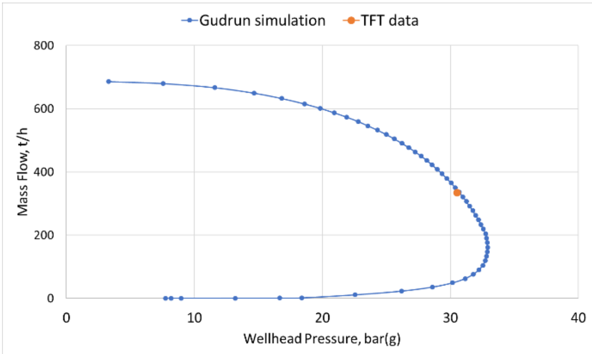

Figure 5. Well A Gudrun simulation - output curve calibration

<u>3.1.3 Well A - Production History Calibration</u>

The mobility-corrected wellbore model was calibrated with the wellhead TFT mass flow and enthalpy data.

Multiple wellbore models were created by running the base model with a range of feed zone pressure and enthalpy inputs based on reservoir trends. The feed zone pressure and enthalpy trends were based on Well A PTS surveys carried out between 2012 and the end of 2015. The average reservoir pressure trend was declining at around 0.015 bar/yr while the reservoir temperature trend was cooling at around 1.9 °C/yr.

The results of the Gudrun wellbore simulations were plotted against the TFT mass flow and enthalpy as show in Figure 6.

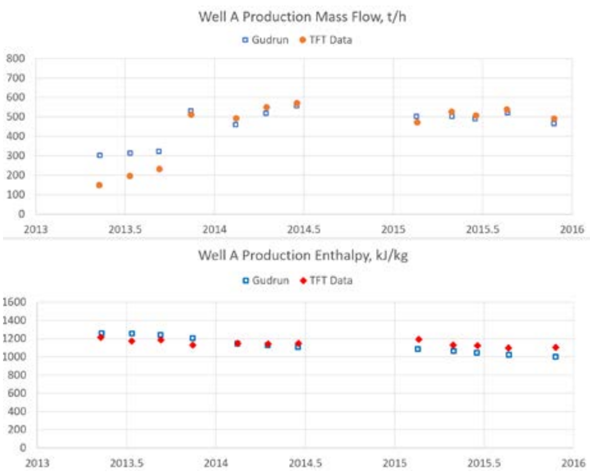

Figure 6. Well A Gudrun simulation - Production history calibration

The wellbore simulation results indicate that Well A's production trends are mainly influenced by changes in the reservoir fluid properties, i.e., pressure decline and cooling, rather than changes in feed zone permeability or other flow assurance issues such as wellbore scaling.

3.1.4 Well A - Wellbore Model Forecast

The mobility-corrected wellbore model and the reservoir trends were then used to forecast the future performance of the well at an assumed production wellhead pressure. A forecast of Well A is shown in Figure 7 at an assumed reservoir pressure and enthalpy forecast.

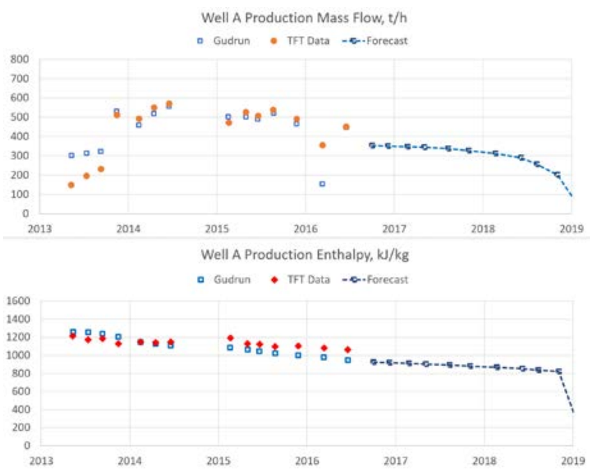

Figure 7. Well A Gudrun simulation – forecast at 10 bar(g) wellhead pressure

If the wellhead production data is consistent with the forecast, it is a reasonable assumption that the same reservoir processes and trends are still relevant, and that the wellbore simulation is an appropriate representation of the well performance.

Divergence from the forecast is an indication that a different process is likely occurring, and additional investigation or downhole surveys are required to update the wellbore simulation. This implies that downhole surveys could become optional based on the consistency of the wellhead data with the forecast, allowing for a more optimised well operation and cost-effective data collection.

3.2 Injection Well B

Well B is a deep reinjection well that injects 90-100℃ of geothermal water and steam condensate from the TOPP1 power plant in Kawerau. The injection well capacity is observed to decline at a rate of around 8-10% per year.

This case study aims to confirm whether the framework could be used to match declines in injection capacity and whether it could provide additional insights into the decline process and options for mitigation.

3.2.1 Well B - Conceptual Model

Well B is a deep reinjection well completed with a 9 5/8" ID production casing set at 1402m CHF (casing head flange reference). It has a 7" ID perforated liner inside an 8 ½" ID borehole with the top of the liner at 1375 m CHF down to total depth at 2476 m CHF.

Initial injection well characteristics based on the well completion test indicates good injectivity at around 100 t/h/bar at 90℃ injected water. This injection permeability is split between a shallow zone at around 1595-1620m CHF and a deep zone at around 2290-2350m CHF.

Heat-up runs indicate that the injection area has a reservoir temperature of at least 200℃.

Injectate chemistry is oversaturated with respect to silica. In this regard, the injectate's pH was modified to retard silica polymerisation and mitigate silica deposition. However, injection capacity was still observed to decline from the onset of injection in 2014.

After nearly two years of continuous injection and observed capacity decline, downhole injecting PTS and a pressure-transient analysis (PTA) indicated that Well B's deep zone injectivity had decreased by more than half of its initial injectivity, and that a positive 'skin' damage was evident in the PTA. These observations, in addition to the silica content of the injectate, indicated that Well B's injectivity was declining due to silica deposition in its injection zones.

However, the downhole temperature profile at the end of the PTA also indicated that the maximum temperature of Well B's injection zones had now declined to around 95℃ (Figure 8). Well B's wellbore pressure profile also reflected the change in temperature, with a pressure gradient equivalent to that of a reservoir at 95℃ as shown in Figure 9.

Gudrun's capability to simulate wells using mobility-corrected feed zones was used to determine whether the decline in injectivity and injection capacity could be explained by this observed cooling. The same framework in Figure 1 was used to carry out the well diagnostics.

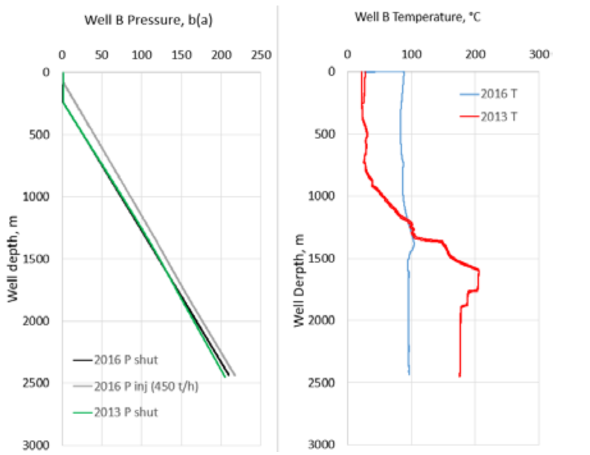

Figure 8. Well B pressure and temperature profiles indicating the effects of cooling on the reservoir pressure gradient.

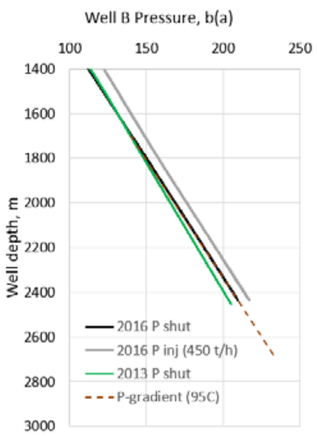

Figure 9. Well B pressure profiles indicating match to colder pressure gradient.

3.2.2 Well B - Wellbore Model

The Well B wellbore model was built in Gudrun using the initial well and reservoir conditions described above in the conceptual model. A "Downwards" simulation was carried out, manually selecting the water level inside the Well B as the initial elevation, and using the homogeneous pressure drop correlation to model the injection of 60 t/h of 20°C water.

The wellbore simulation was calibrated with the completion test pressure and temperature profiles as shown in Figures 10-12.

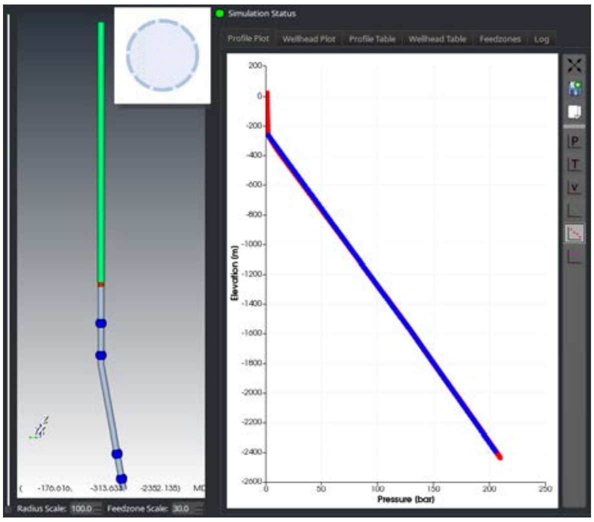

Figure 10. Well B Gudrun simulation - pressure profile calibration

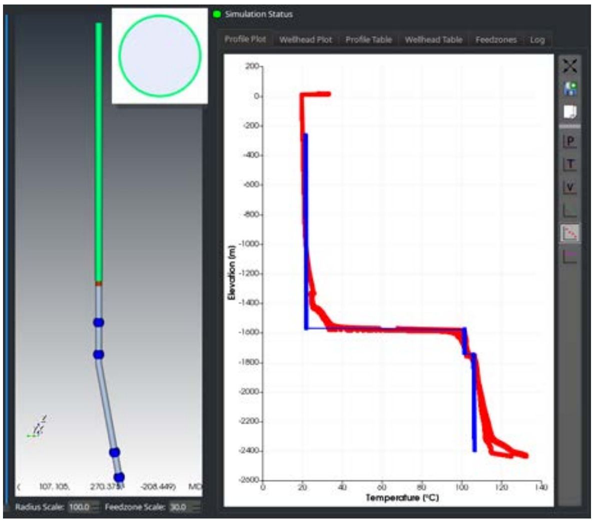

Figure 11. Well B Gudrun simulation - temperature profile calibration

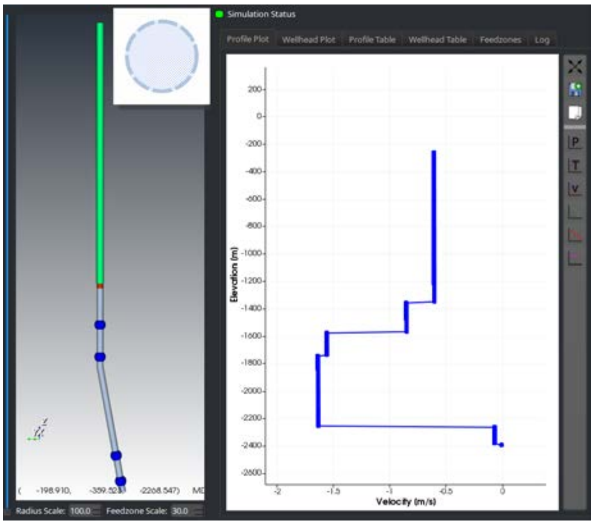

Figure 12. Well B Gudrun simulation - velocity profile

Table 2. Well B mobility-corrected FZ permeability

FZ elevation [m]	kh [m^3]
-1579	1.13E-11
-1750	9.71E-12
-2265	2.43E-11
-2395	7.00E-13

From the initial wellbore calibration, mobility-corrected feed zones (Table 2) were used to generate the base wellbore model for injection history calibration. The initial injection curves from the base model at two different injection temperatures are shown in Figure 13. Based on injected temperature alone, the increase of injection temperature from 20°C to 90°C reduces the injection capacity by 5-6% at low injection wellhead pressures.

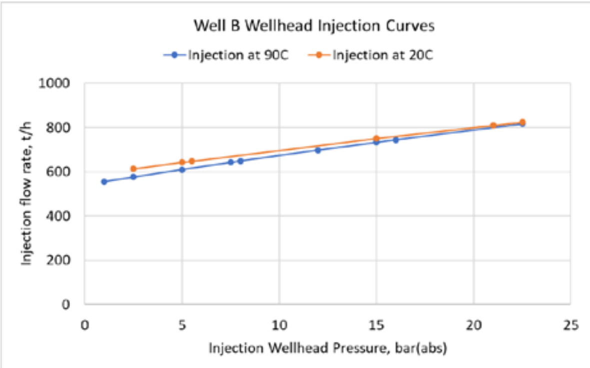

Figure 13. Well B injection curves at different injection temperatures using mobility-corrected FZ permeability

3.2.3 Well B - Injection History Calibration

Multiple wellbore models were created using the base wellbore model and editing the feed zone pressure and enthalpy inputs based on reservoir trends. The feed zone pressure and enthalpy trends were based on Well B's PTS surveys as shown in Figure 8.

The main reservoir trend modelled was a reservoir temperature change from around 200°C, measured in 2013, at the start of injection in 2014 to around 95°C in 2016, while keeping the mobility-corrected feed zone permeability constant. The results of the Gudrun wellbore simulations are shown in Figure 14.

The reservoir cooling described in Figure 8 and Figure 9 result in an injection capacity decline of around 17% from the 2014 injection capacity, with no changes to the mobility-corrected feed zone permeabilities.

The gross well injectivity index from the Gudrun simulation results indicate that Well B's total injectivity has declined by about 48% between 2014 and 2016, resulting in the 17% injection curve decline in Figure 14.

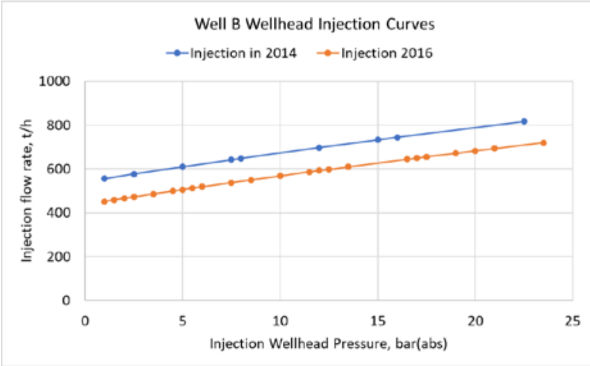

Figure 14. Effect of reservoir cooling on Well B injection curves.

3.2.4 Well B - Well Diagnostics

Well B's injection capacity decline appears to be partly caused by density changes in the near-wellbore reservoir. The density change could be explained by cooling, resulting in a back-pressure effect on injection Well B, with no changes to feed zone permeability.

The pressure transient analysis (PTA) showing positive "skin" damage is likely due to the cooler near-wellbore reservoir resulting in a composite reservoir effect. It is likely that a colder and denser region adjacent to Well B acts like a positive skin damage before the injectate heats up to hotter reservoir conditions away from the well. A similar observation has been reported by MacLean and Zarrouk (2015), modelling the pressure transient effects of cold-water injection into a hot reservoir.

Injecting colder fluid into a hotter reservoir usually results in increasing injection capacity due to thermal stimulation (Grant et al., 2013; Clearwater et al., 2015). In this particular case, Well B and its surrounding reservoir appears to not have thermally stimulated. Rather, the continuous injection seems to have cooled the well and the nearby reservoir, resulting in an increase in the reservoir density and likely increased fluid viscosity, all contributing to an apparent decline in injectivity.

While silica deposition is still likely occurring and contributing to ongoing capacity decline, the temperature effect on the injection capacity decline highlights the significance of cooling and the limitations of capacity recovery through costly well workovers such as injection well acidizing.

The Well B case study could also potentially explain some of the relationship between reservoir temperature and injectivity as described by Siega et al. (2014). Further wellbore simulation investigation and case studies are recommended to verify this.

4. RESOURCE MANAGEMENT IMPLICATIONS

Gudrun's capability to model mobility-corrected feed zones and to be automated using scripts will enable the advancement of wellbore simulations as effective tools for production optimisation and resource management outside of in-house software packages.

Mobility-corrected wellbore models calibrated to production or injection history allows for wellbore model-based forecasts, with variable operational conditions accounted for in the output curves of the forecast models. This allows for a more realistic expectation around fluid availability based on operational limits and highlights opportunities for steamfield optimisation if bottlenecks are apparent.

Wellbore model-based forecasts could also optimise reservoir surveillance and monitoring activities, increasing survey frequency on critical wells or wells diverging from the forecast while deferring surveys on relatively stable wells.

Mobility-corrected wellbore models are also very useful when investigating changes to well productivity and injectivity due to pressure and temperature changes in the produced/injected fluid and in the reservoir. This will increase the accuracy of well capacity estimates, ensuring effective well diagnostics and geothermal field management.

5. CONCLUSION

The Gudrun wellbore simulator was successfully used to implement the framework for wellbore simulation in well diagnostics and forecasting.

As shown in the case studies, mobility-corrected wellbore models advance the use of wellbore simulations in operations and resource management, providing an additional tool in sustainable geothermal field operations and resource management.

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