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Reservoir Quality Requirements for Geothermal Developments in Deep Sedimentary Basin

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ABSTRACT

Deep sedimentary basins are investigated worldwide for geothermal power and direct-use applications. While low temperature direct use applications are widely developed and in operation, the development of geothermal power generation in the same geological settings had highly variable success rates. The need for temperature above 100-120 °C leads to targeting hydrothermally active faulted areas or more generally greater depth. With depth comes the increase of cost, uncertainties and risk for the project. One specific uncertainty to consider is the quality of the targeted geothermal reservoir. Reservoir quality can vary significantly within a basin or even sub-basin, depending on the local depositional, tectonic and diagenetic history. Reservoir quality impacts the resource volume calculation and the deliverability of the wells which then inform the economic model.

In this work, we investigate the impact of the requirements on reservoir quality for the development of power generation in deep sedimentary basins.

1. INTRODUCTION

Geothermal energy for commercial power generation has been mainly harvested from volcanic regions on tectonic plate-boundaries such as the Pacific "Ring of Fire". Geothermal energy has also been developed in sedimentary basins generally at a smaller scale for local often direct use application and referred to as hot sedimentary aquifer (HSA) geothermal or hydrothermal. Typically, these resources occur at shallow to moderate depth (generally less than two to three kilometers) and the typical temperature gradients for sedimentary basins is 25-40°C.km^{-1}. The range of temperatures associated with sedimentary basins and regional aquifers is estimated as 20 °C to 150 °C (Lund et al., 1998). Low enthalpy geothermal resources are water-dominated (i.e. no steam phase) and usually close to hydrostatic pressure. In most cases, the water temperature increases with depth, i.e. according to the mean geothermal gradient and the water is gaining heat by vertical heat conduction and heat advection resulting from the circulation of groundwater through permeable zones within the aquifers.

Geothermal resources hosted within sedimentary basins have been successfully explored and developed for geothermal energy extraction worldwide (Lund et al., 1998, 2011) for millennia and across most continents. There are numerous studies and reviews about direct-use geothermal and the description of several low enthalpy geothermal resources (Antics and Rosca, 2003; Lopez et al., 2010).

Most geothermal applications associated to deep and hot aquifers in conductive thermal regimes are direct-use. Geothermal in sedimentary basins is well established at small scale (< 5 MWt/ well) for direct-use projects. Direct use of geothermal energy can be applied to a wide range of applications (Barbier, 2002) and is typically associated with lower-temperature geothermal resources (those with a temperature of less than 150°C), though some applications may require higher temperatures. The technology, reliability, economics and environmental benefits of direct-use geothermal energy has been demonstrated in a wide range of settings throughout the world (Lund et al., 2011) although most of the usage is for residential purpose and industrial applications represent less than 3% of the total energy use. Some direct-use applications have a narrow working temperature window whereas others are widespread. Therefore the sophistication employed in the temperature analysis and thermal characterization of the geothermal reservoir must match the flexibility/ complexity of the temperature requirements of the envisaged direct use application(s).

While few small-scale power generation projects exists (Sanyal, 2009; Popovsky, 2013), it is yet to gain momentum due to the difficulty to find the right combination of aquifer temperature and quality. Large scale power generation (> 5 MWe) does not exist yet for sedimentary basins. A current limitation of the power plants exists on the lower input temperature which is recorded at 98 °C in Australia but 74 °C in Alaska. Current theoretical efficiency is about 45% (Sanyal, 2009), however Zarrouk and Moon (2014) reports for ORC lower practical efficiencies (less than 10%) for the same range of temperature. Electric power production by binary plants using the Organic Rankine Cycle or the Kalina Cycle requires fluid temperatures ranging from 85°C to 150°C while conventional geothermal power plants require temperatures of more than 150°C to be viable. The binary cycle technology with Organic Rankine Cycle (ORC) appears to be the most efficient in comparison to dry steam, single and double flash steam plants, and convenient solution for resources with temperature lower than 150 °C. In Plants using this technology, the thermal energy of the fluid is transferred through a heat exchanger to a binary conversion in which a secondary fluid works in a closed cycle (Figure 2). Binary plants are available of a lot of different designs linked to the specific working fluid and reservoir conditions (pressure, temperature, chemical composition and flow rate).

Sanyal (2009) has demonstrated that for power generation in sedimentary basins, aquifer quality has a more significant impact on the economics than temperature which can be directly associated with the range of variation of the aquifer permeability.

2 LOW TEMPERATURE GEOTHERMAL ENERGY IN AUSTRALIA

Geothermal energy has been used in Australia since the beginning of the 20^{th} century with numerous direct-use applications (Cull, 1985; Burns et al., 1995; Burns et al., 2000) with most of the activity in Victoria such as paper manufacturing in Taralgon, a 39 MWt installed capacity district heating system at Portland, two fish farms, a meat processing plant associating direct-use and electricity co-production. A vast number of tourist attractions can also be found in the Great Artesian Basin. Concurrently to direct-use geothermal projects, two geothermal power plants have been developed. The first one at Mulka (South Australia), started in 1986 utilizing 86 °C water to produce 20 kWe (Popovsky, 2013). The second power plant in Birdsville (Queensland) benefits from 98 °C water to produce 150 kWe gross.

There are several commercial direct use geothermal projects in Perth, producing geothermal fluid from the Yarragadee Aquifer. This aquifer is a freshwater aquifer that supplies a significant portion of Perth's potable water. The Yarragadee Formation is a Jurassic non-marine fine to coarse-grained, poorly sorted feldspathic sandstone that has high permeabilities with a maximum thickness of 4,000 m. These direct use projects primarily use the geothermal energy to heat swimming pools and with the exception of the Bicton Geothermal Therapy Pool, all water is re-injected into the aquifer. Details of these systems are presented in Pujol et al., 2015.

Recently, two projects targeted deep HSA resources with exploratory drilling: Panax Ltd drilled a 4000 m deep well (Salamander-1) to test the Pretty Hill Formation in the Penola Trough of the Otway Basin (South Australia) and Origin Energy Ltd drilled a 2416 m deep well (Celsius-1) targeting the Hutton Sandstone in the Nappamerri Trough of the Cooper region (South Australia). These resources have been considered because of their potentially high natural permeability, the presence of water, suitable temperatures and the lateral extent of their resources. However, unexpected low flow rates at the target temperatures required for power generation raised the question of the feasibility and development of large-scale power generation from sedimentary reservoirs and by way of consequence the required geothermal exploration and development frameworks.

3. GEOTHERMAL ENERGY IN SEDIMENTARY BASINS

Production of geothermal heat in sedimentary basins has received a lot of research interest over the last decade. Some of the outstanding contributions are Sanyal et al. (2007), Sanyal and Butler (2009), Ungemach and Antics (2009), Sanyal and Butler (2010a, 2010b), and van Wees et al (2012). Key aspects of geothermal production in sedimentary basins are discussed below, further details can be found on the references above.

Geothermal production considerations include production power, temperature and chemistry of the working fluid and sustainability of the production rate. The efficiency of a geothermal system is linked to the recovery factor and the mechanism of energy conversion while the expenditures are driven by the exploration, capital and maintenance costs.

For low temperature geothermal reservoirs, large pressure gradients are required to move fluid towards the production wells. Production of geothermal fluids creates pressure losses. If the reservoir is initially over-pressured, the well will flow naturally and the pressure losses can be partially to totally offset. It is rare but not impossible to find an artesian HSA. However, without any injection the reservoir pressure will continue to decline until the reservoir recharge imposes the production rate. In many cases, without injection, the pressure will drop below economic project viability. To reduce the pressure loses, the field development commonly used for low temperature geothermal projects is the 'well doublet' defined by Gringarten (1978). A well doublet development is composed of a well for production and a well for injection. The hot water is produced, then circulated into a heat exchanger and then re-injected using the injector well. This principle is used for both power generation and direct use projects. Reinjection is a very important part of a geothermal development for providing pressure support (Kaya et al., 2010). Re-injection is also envisaged as a solution for produced fluid disposal and limit subsidence if large amounts of fluid are withdrawn. A key advantage is the reduction of the reservoir pressure losses which then affect the pumping power and pumping cost. Despite been critical for a long-term management of a geothermal project, reinjection has several disadvantages and difficulties (Sanyal et al., 1995) that can jeopardise the geothermal project.

Water re-injection does not necessarily off-set totally the pressure losses. The challenge is then to supply pumping power to the system so that the reservoir fluid can be recovered at the surface. A careful optimization of the pressure losses enable to limit the number of pump and the pumping power required. The pumping power required is a direct on-going cost associated to the heat production which will affect the economics of the project. By definition, in a pumped bore the pumping power P_{pump} (W) is given by the following equation:

$$P_{pump} = \frac{Q.\Delta p}{\eta_{pump}} \tag{1}$$

where Δp and η_{pump} are the pump total dynamic pressure change (Pa) and the pump efficiency respectively. The pump total dynamic pressure change (Sanyal et al., 2007; Ungemach and Antics, 2009; van Wees et al., 2012) can be estimated using the equation below:

$$\Delta p = \Delta p_0 + \Delta p_r + \Delta p_s + \Delta p_{fr} + \Delta p_{HX} + \Delta p_i \tag{2}$$

where Δp_0, Δp_a, Δp_s, Δp_f, Δp_{HX}, Δp_i are the difference to hydrostatic pressure (Pa), the aquifer pressure drawdown (Pa), the skin effect pressure drawdown (Pa), the friction induced losses in the bore casing and screens (Pa), the friction induced losses through pipework, heat-exchange units, inline-filter and control valves (Pa) and the injection overpressure above ground (Pa). Details on the formulae of the different pressure losses term can be found in the above references.

The main pressure losses are the aquifer pressure drop, the friction losses in the wells and the friction losses in the surface facility. They are associated to reservoir, well and surface facility characteristics. van Wees et al. (2012) presents the DoubletCalc software which enables pressure losses calculation and much more.

The reservoir pressure losses for a single well production scenario are defined as:

$$\Delta \mathrm{p}_r = \frac{Q\mu}{2\pi kh} \ln\left(\frac{kt}{\phi c_t r_w^2}\right) \tag{3}$$

where μ is the working fluid viscosity (Pa s), Q is the flow rate (m^3/s), k is the reservoir permeability (m^2), t is the time (s), ϕ is the porosity, C_t is the total compressibility, r_w is the well radius (m) and h is the completed length (m).

The reservoir pressure losses for a doublet (production and injection) production scenario are defined as:

$$\Delta \mathrm{p}_r = \frac{Q\mu}{2\pi kh} \ln\left(\frac{L}{r_w}\right) \tag{4}$$

where L is the distance between the two wells (m).

The bottom hole completion pressure losses often referred to as skin pressure drawdown is defined as:

$$\Delta \mathrm{p}_s = \frac{Q\mu}{2\pi kh} S \tag{5}$$

where μ is the groundwater viscosity (Pa s), p_D is a dimensionless pressure, kh is the reservoir transmissivity (Dm) and S is the skin factor.

The pressure losses associated to the friction are detailed in van Wees et al. (2012) as:

$$\Delta \mathrm{p}_{fr} = \frac{f\rho v^2}{2D} Z_w \tag{6}$$

where f is the Moody friction factor, v is the diameter-averaged flow velocity within the well, D is the well internal diameter (m) and Z_w is the well length from mid-screen to surface (m).

The friction coefficient is a function of the Reynolds number, the roughness of the tubing surface and the diameter of the well.

The reservoir pressure losses for a single well scenario double over a 20 years period. However, the pressure losses associated with a production doublet is not affected by time (Figure 1b). The difference between single well and doublet pressure difference is more pronounced for high flow rates. For a 100 kg/s flow rate, this could represent 300 kPa. Reservoir pressure drawdowns after 20 years for different reservoir permeability-thickness product are presented in Figure 1b after 20 years of operation. As expected, the higher the permeability-thickness product, the lower the pressure drawdown. For comparison, the permeability-thickness product is estimated between 75 to 1000 Dm for the direct use HSA geothermal project in the Perth Metropolitan Area (Western Australia). The pressure difference increases with flow rate as we would expect. The initial reservoir pressure should be considered in the graph as the very upper limit of possible pressure difference although economics limitations are likely to be much lower. For a reservoir depth of 3000 m, hydrostatic conditions would be ~30,100 kPa. For 100 kg/s flow rate, this imposes a permeability-thickness higher than 5 Dm. A change of the permeability-thickness product of one order of magnitude changes the pressure drawdown prediction by one order of magnitude. A pressure drawdown of less than 1MPa with a 100 kg/s flow rate requires a permeability-thickness higher than 50 Dm.

Pressure losses due to frictions are another key contributor to the overall losses (Figure 2). They are critically dependent on flow rate and casing/ tubing diameter. For high flow rate (50 kg/s and above), the friction pressure losses have the same magnitude than reservoir pressure losses for 6” and 8” casings. However, they have less amplitude with 12” or above casing size. Pumping power associated to the reservoir and friction losses was estimated for a range of permeability-thickness product and a range of flow rate (Figure 3).

If the well is completed across the entire reservoir thickness then both well completion length and reservoir thickness are equal. However, the well completion length is very often less than the reservoir thickness. The thickness of a reservoir is controlled largely at the time of deposition of the sediments that make up the reservoir. The permeability of the rocks in a reservoir will have been modified by diagenetic processes that begin penecontemporaneously with deposition.

(a) (b)

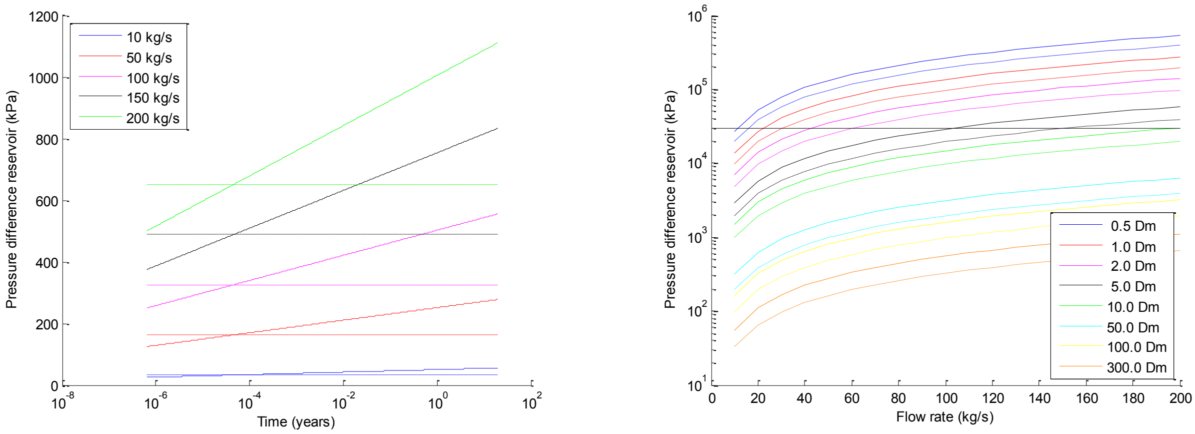

Figure 1. (a) Reservoir pressure difference changes over time for selected flow rate for a single producer (line) and a well doublet (dashed lines) over 20 years. The reservoir transmissivity is 300 Dm. Porosity is 15% and well distance is 1,000 m.(b) Reservoir pressure losses after 20 years of production as a function of flow rate for different reservoir permeability-thickness product. The horizontal black line represents the hydrostatic reservoir pressure.

(a) (b)

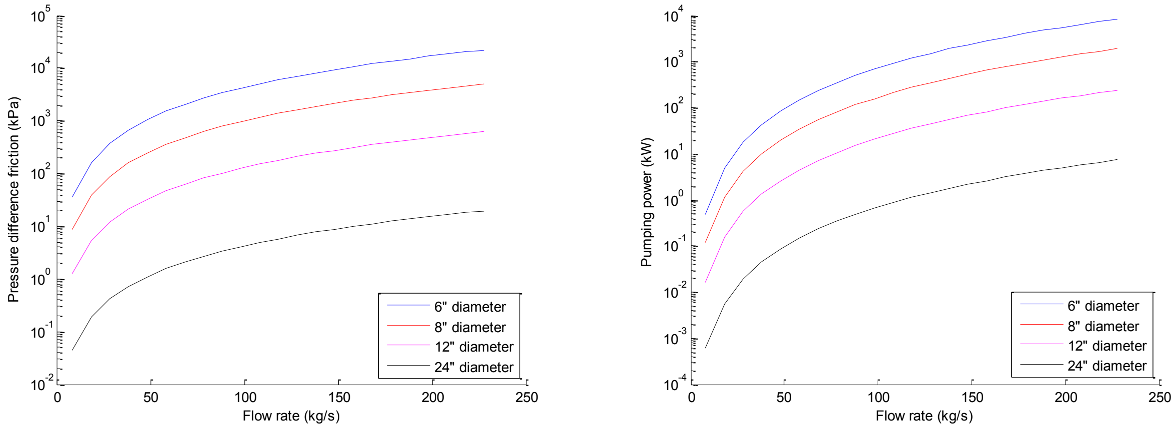

Figure 2. Friction pressure losses and associated pumping power as function of the flow rate and the tubing inner diameter. The well is assumed to be 3000 m length.

(a) (b)

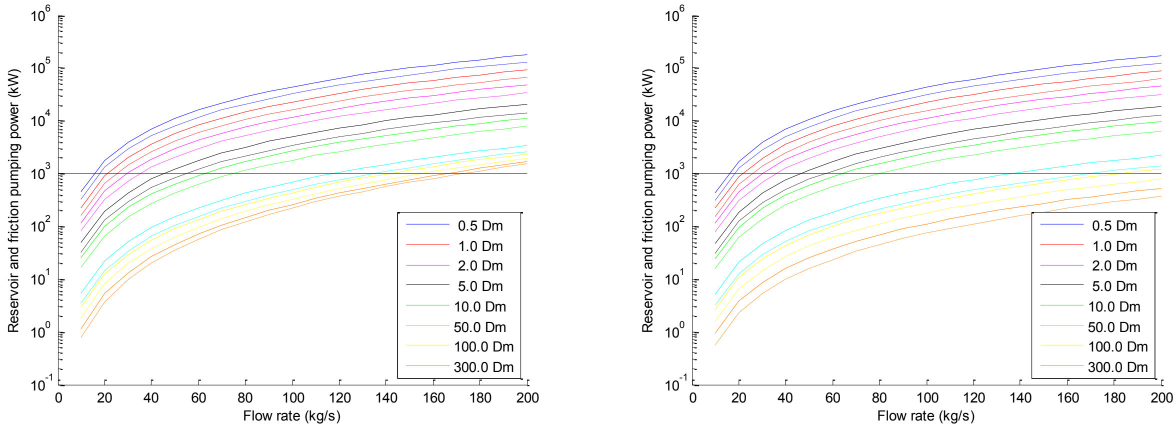

Figure 3. Pumping power required to overcome reservoir and friction losses (only for the producer) as a function of the flow rate. The well is assumed to be 3000 m length. Well diameter is (a) 8” and (b) 12”. Pumping power of 1MWe is presented with a horizontal black line for comparison purpose.

CONCLUSION

A flow rate of 100 kg/s is regarded as the critical flow rate threshold for large scale power generation in HSA (Huddlestone-Holmes et al., 2014).

From this preliminary study, in order to achieve flow rates greater than 100kg/s without applying more than 1 MW of pumping power, a permeability thickness of at least 50 Dm is required for an 8 inch well and at least 10 Dm for a 12 inch well. 10 Dm could be achieved through a well completion that is 10 m thick with average reservoir permeability of 1 D, or 500 m thick with an average reservoir permeability of at 20 mD. This analysis helps to provide the constraints for the parameters required for a sedimentary geothermal resource to be successful. The minimization of the losses is a compromise between the reservoir permeability-thickness product which can be modified to some extent by stimulation or well completion length and the well diameter.

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