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Alberta #1: The Province's First Electrical Geothermal Project

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ABSTRACT

In Canada's western provinces, the Western Canada Sedimentary Basin (WCSB) is known to have warm to hot brines in large extractable volumes from permeable, hydrocarbon-bearing units. In Alberta's northwestern region, the Municipal District of Greenview (MDGV) was actively supporting preliminary resource investigations within its lands. These investigations led to the determination that there was an economically viable resource under the MDGV and, in particular, near a new Heavy Industrial District (HID) development planned for a large tract of land south of the city of Grande Prairie. Alberta #1 (as the project has been named) will provide the industrial park, referred to as the Tri-Municipal Industrial Park (TMIP), with both electrical and thermal energy produced by the project. The research suggests that temperatures above 120°C are attainable at depths of 3,500 m and below. The target formations at these depths are under the Beaverhill Lake Group and are comprised of the Swan Hills, Granite Wash, Gilwood, the basement unconformity and the basement itself. Importantly, the targets are below the hydrocarbon and shale-rich Duvernay Formation. Only two wells within the TMIP have been drilled to basement, and only a handful of wells are drilled below the Duvernay Formation. There is limited flow rate test data on the target formations but extrapolating from similar target formations elsewhere, it is anticipated that flow rates in 7-inch pipe will exceed 30 l/s and the total flow rate required for 8MWe (gross) generation is 300 l/s. Fluid chemistry modelling of existing analytical data suggests that there will be no major issues with mixing of formation waters and proposed injection into the producing aquifer or the Leduc Formation.

1. INTRODUCTION

The MDGV, located in northwestern Alberta, Canada, has a significant energy resource in the form of heat within the oil and gas reservoirs currently being tapped by wells drilled within the MDGV for hydrocarbon production. This resource will be tapped in the Alberta #1 geothermal electricity generation and thermal project led by Terrapin Geothermics (Terrapin).

The project was funded initially by the MDGV and Terrapin, with the data being gathered and analyzed in response to a request for proposals from Canada's Federal Department of Natural Resources (NRCan). The funding was through the "Emerging Renewable Power Program" (ERPP) which sought to provide support to projects with the potential to produce at least 5MWe (net) electrical power. In 2018, a project in Saskatchewan, proposed by DEEP Earth Energy Production Corp. (DEEP), was funded through the program; DEEP's first well was subsequently drilled in December 2018. Funding of $CDN25.4 million for Alberta #1 was announced in August 2019 under the same program. This Federally based funding provides a critical infusion of equity to support the early stage exploration of Alberta #1 and DEEP (Hickson et al. 2020)

There have been more than 60,000 wells drilled within the MDGV since the 1950s. Many of these wells tap deep aquifers (formations that produce fluids such as water and hydrocarbons) of warm water in addition to oil and gas resources. The warm water is a source of thermal energy that can be used for electrical generation and direct use applications, particularly given the large temperature variation between the resource and the mean annual temperature (ΔT) for the Grande Prairie, Alberta region of Canada. The low mean annual temperature means a significant number of heating degree days, so even a low temperature resource has sufficient energy content to offset the heating needs of citizens and industry.

Underlying the MDGV are hot sedimentary aquifers (HSAs) that form part of the WCSB. These aquifers show promise for heat extraction using several different approaches. Given the large number of drilled oil and gas wells in the region, there is a possibility that co-produced fluids can be extracted and utilized in parallel with oil and gas production using the existing drilled infrastructure. However, the diameter of the well liners in oil and gas production zones (4 ½ or 5 ½ inches and sometimes 7 inches) do not provide sufficient mass flow for economic production of geothermal fluids. There may be options for waste heat generation from these wells with development of more efficient wellhead generators and/or built infrastructure that has heating requirements and is in close proximity.

In addition to the narrow well bore diameters, upper well casing sizes are often too narrow to accommodate the high capacity pumps needed for electrical generation from low temperature, gas-rich fluids (i.e. fluids below <170°C). Pumping the well diminishes the decompression cooling, but many of the wells represent older infrastructure. However, because there are so many wells, the use of abandoned, orphaned, or wells that have been in service for long periods of time, has been reviewed. This review raised concerns over wells, particularly the older ones, that can potentially have well bore integrity issues. Re-entering and reusing wells must be done with caution and appropriate well integrity testing carried out to ensure that the cement and casing integrity is adequate for the desired use. Re-entering wells for the purpose of flow testing and bottomhole temperature (BHT) measurements will be considered as an aspect of the exploration phase of this project, but it is unlikely that wells will be repurposed for geothermal use. For these reasons, Alberta #1 is developing a conventional deep geothermal resource through drilling of purpose drilled wells.

Extensive analysis was undertaken to review the historic BHTs. It was found that older measurements suggested a much higher gradient than more modern wells. Despite the uncertainty of the BHTs, evidence strongly suggests that BHTs will exceed 120°C at

4000 m and flow rates in wide diameter well bores could exceed 50 l/s, but are more likely to be 30 l/s. The project anticipates that production from large-diameter, purpose-drilled geothermal wells will exceed 1MWe power generation with parallel MWth generation for direct use. Once reservoir conditions are better known following testing, it will be possible to refine the development options and economics of the project.

It should be emphasized that any produced geothermal fluid can be used for either indirect utilization (power generation), or direct utilization purposes (heating commercial-scale buildings, greenhouses, district heating, providing waters for spas and swimming pools, lumber drying, etc.). The ERPP development fund was established to promote the generation of electricity from renewable sources and did not take into account the energy potential from projects accessing thermal energy from geothermal sources such as HSAs. However, for Alberta #1, the thermal energy potential is very important for planned greenhouse gas emission offset use in a new HID south of the city of Grand Prairie. Formulated as the TMIP, Alberta #1 plans on providing future tenants of the park with green electrical and thermal energy. It will take further testing and exploration to identify zones with sufficient brine flow and temperatures to produce electricity, but there are unquestionably sufficient resources within the TMIP area to serve as a stable, direct use energy source for many of the commercial and industrial applications planned for the area.

2. TRI-MUNICIPAL INDUSTRIAL PARTNERSHIP HEAVY INDUSTRIAL DISTRICT

The MDGV initially chose to focus the geothermal development project on an under-development industrial park south of Grande Prairie. The TMIP (HID) (Figure 1) is a partnership between the MDGV, the City of Grande Prairie and the County of Grande Prairie and will require significant electrical and thermal energy. Alberta #1, through one of its equity partners, MDGV, will focus on attracting specific heavy industrial users that directly benefit from co-location with a hydrocarbon source and infrastructure (road, pipeline, and rail). Tenants of the MDGV will benefit from access to green electricity and thermal energy provided by Alberta #1.

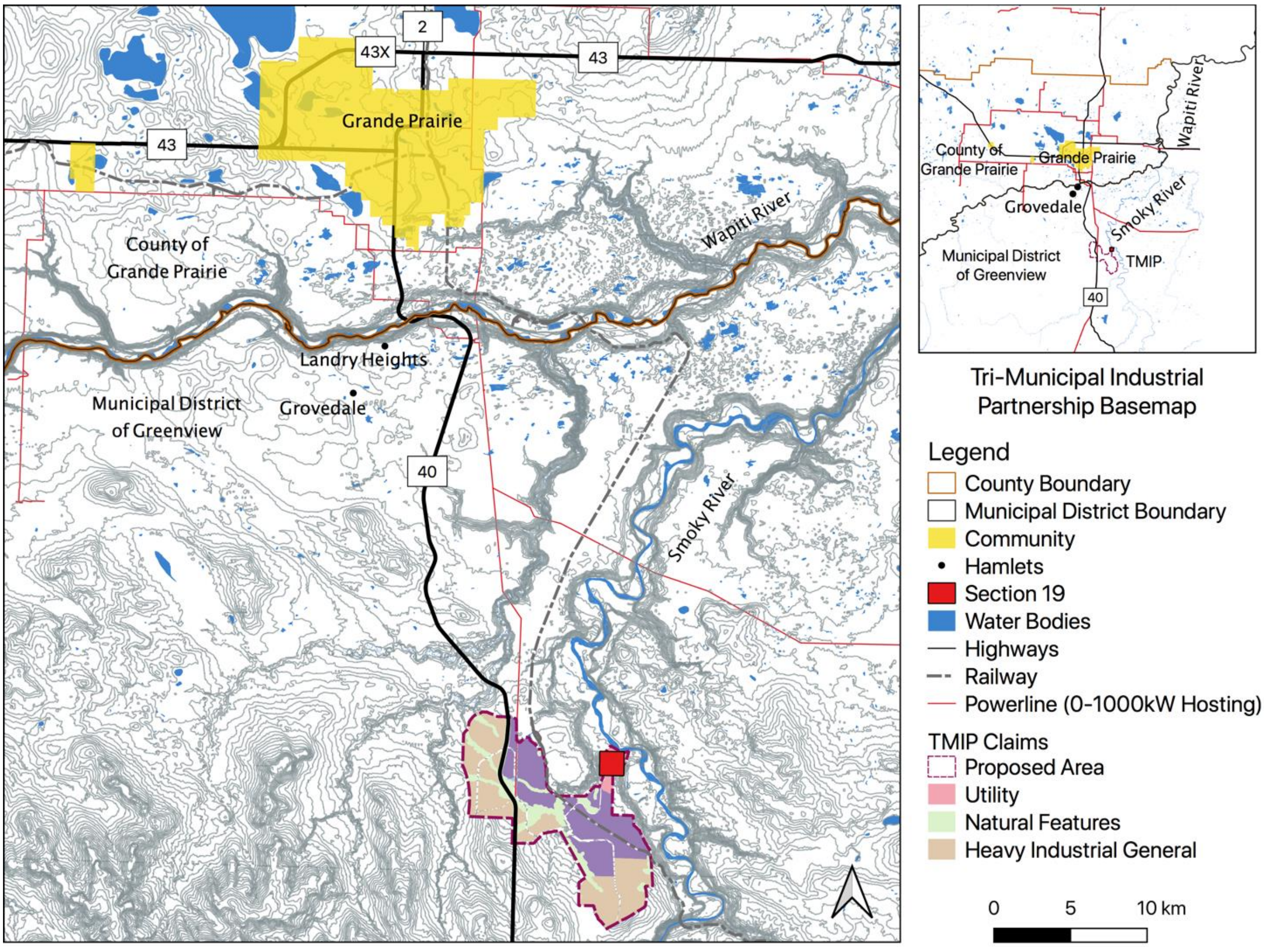

Figure 1: Regional Base Map of Tri-Municipal Industrial Partnership (purple outline) south of the City of Grand Prairie (yellow block) within the boundaries of the MDGV. The TMIP boundaries are provisional at this time and subject to change. The project site is shown by the red square "Section 19".

The MDGV is working with the Alberta Ministry of Environment and Parks (AEP) to create a 25-year plan to provide a land use, infrastructure, and policy framework that will attract future industrial activities to the plan area, thus reducing the risk of industrial sprawl. It also creates a focus area that is more suitable to the concept of district heating. Additionally, the area is directly linked to the City of Grande Prairie, and thus to the City of Edmonton, making up a section of the Canada-Mexico (CANAMEX) trade corridor linking the region to international markets.

Near the TMIP District, there is a development in the town of Grovedale, which is part of the MDGV. The MDGV has made the statement that all future residential, commercial, industrial, and institutional new construction or renovations should incorporate systems for generating renewable energy, such as solar panels, geothermal heating (ground-based and deep, low temperature geothermal), or wind turbines (Grovedale Area Structure Plan 2018). They have also made the declaration that individual ground-based geothermal heating systems are encouraged for residential structures. For commercial, industrial, and institutional uses there should be a District Energy Sharing System that could be expanded to residential structures based on the outcomes of feasibility studies.

These publicly stated values for Grovedale made by the MDGV reflect the elected Council's desire to create a more sustainable industrial park. Although the MDGV has not called the TMIP development an eco-industrial park (EIP), the aims of both are similar. By definition, an EIP is an industrial park that aims to achieve sustainable development by cooperating with other businesses and the local community to reduce waste and pollution and share resources such as information, materials, water, energy, infrastructure, and natural resources. An eco-industrial park is the sharing of green, sustainable, base-load (firm) electricity and thermal energy that is driving Alberta #1 to develop a project focused on the use of geothermal energy for both electrical and thermal applications within the MDGV.

Early in 2018, the MDGV engaged Terrapin to develop a proposal for electrical and thermal energy generation based on previous work done in the area of Fox Creek (Hickson et al. 2018a). Coincidently, Canada's federal government, through Natural Resources Canada (NRCan) announced a grant program entitled "Emerging Renewable Power Program" (ERPP). Under this program, Canada's federal government is providing significant dollars to expand the portfolio of commercially viable renewable energy sources available to provinces and territories as they work to reduce GHG emissions from Canada's electricity sectors (NRCan ERPP 2018). The funding submission for the ERPP was completed in 2018 and updated in early 2019 in order to provide a substantive impetus for the planning of the TMIP in terms of providing the site with green energy and a path to sustainability. In June 2019, a new Special Purpose Vehicle (SPV) was created to move the development forward. The SPV, named Alberta #1, has the responsibility to develop the project on behalf of NRCan and SPV equity investors who are currently, Terrapin, PCL Construction Company, and MDGV. In August 2019, the Government of Canada announced $25.45 million (CAD) in funding to Alberta #1 through NRCan's ERPP.

3. ENERGY RESOURCE ASSESSMENT PARAMETERS

3.1 Target Strata

Subsurface data was extracted from data sets acquired from hydrocarbon drilling operations and tests of wells drilled within the TMIP, additional wells outside the study area, and previously written reports and documents. There are 3011 wells within the project target area; 2141 of these wells are single-operation wells with unique data sets. Of these, there are 603 inactive and 1538 active wells (Figure 2). Active wells include wells where the latest reported status implies any type of operation from pumping and flowing to testing and drilling. Inactive wells include wells that are abandoned, closed, canceled, and/or junked. At the time of writing, none of the wells discussed in this paper have been visited in the field.

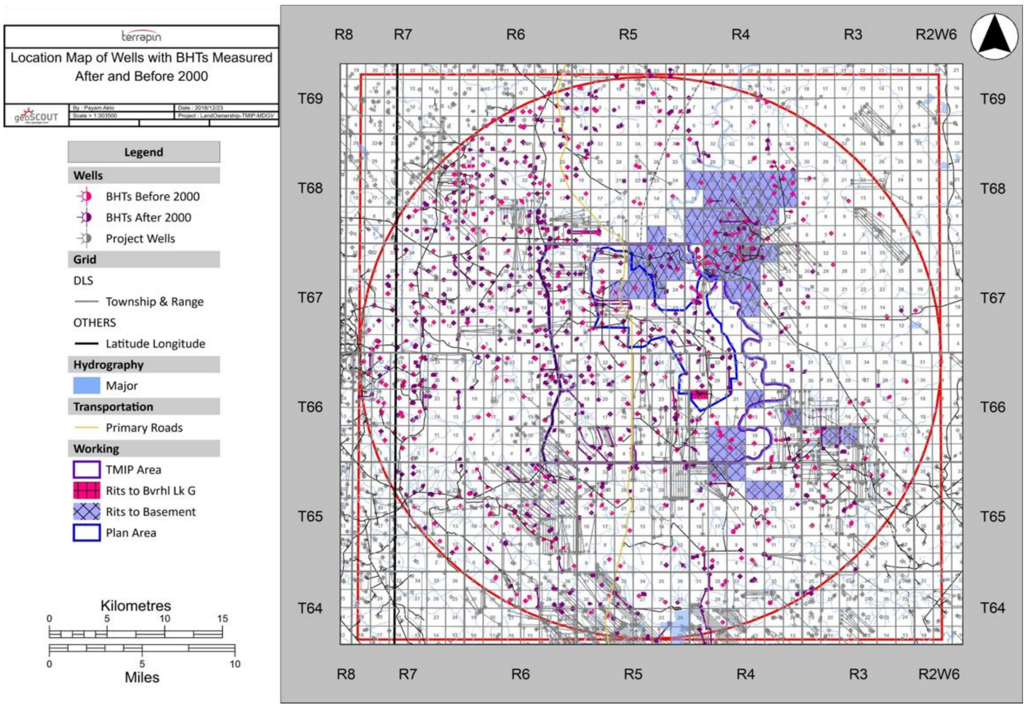

Figure 2: Tri-Municipal area divided into four quadrants (separated along the township and range boundaries). Wellheads and tracks are shown for the 1538 active wells (blue) and the 603 inactive wells (red). Details of the wells were obtained using GeoScout from publicly available wells data accessed through Alberta Energy data repository.

To prioritize the research, geological data and individual well fluid production were reviewed using the pertinent existing geological and geothermal research studies. The most recent (other than Terrapin's own work) was published by Majorowicz and Grasby (2019). This work built on the earlier studies of Banks (2017), Gray et al. (2012), Weides et al. (2014) and others. All of these studies identified the Leduc, Swan Hills, Gilwood and Granite Wash formations (all Devonian age) as prospective geothermal resources in Alberta and which underlie the project area. In addition to these target aquifers, the unconformity between the overlying sedimentary sequence and the metamorphic basement rocks including the basement, may be an important aquifer. In other areas it is reported as altered and permeable (DEEP, corporate communication, January 2019).

These Devonian-aged subsurface formations are comprised of limestone, shale and various other types of sediments deposited between 419.2 and 358.2 million years ago. Various formations within the Devonian stratigraphic sequence were found to have characteristics that make them suitable for geothermal fluid production (cf. Banks 2017; Gray et al. 2012; Majorowicz and Grasby 2010, 2014, 2019, Weides et al. 2014). These formations are also major oil and gas plays (Hickson et al. 2018a and others).

The TMIP is located to the south of the Peace River Arch (

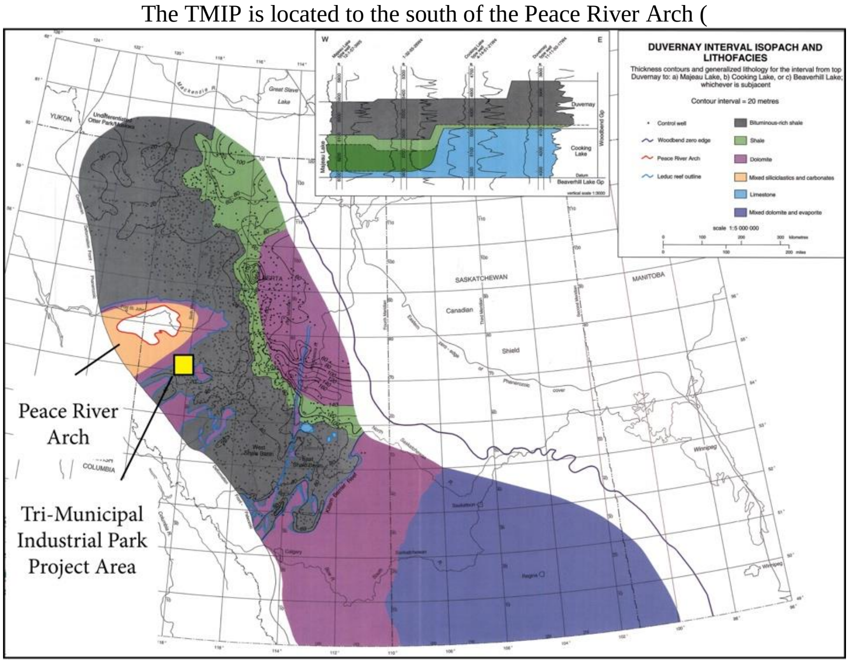

Figure 4 and Figure 4), a significant uplifted basement structure that influenced the deposition of sediments in the WCSB during the Devonian. Devonian strata are also the source of an important hydrocarbon play in strata named the Duvernay Formation in western Alberta. The Duvernay Formation has a high hydrocarbon potential (up to 11% total organic carbon) and low water production. It is fracked to liberate the hydrocarbons and is currently one of the most commercially important oil and gas plays in Alberta.

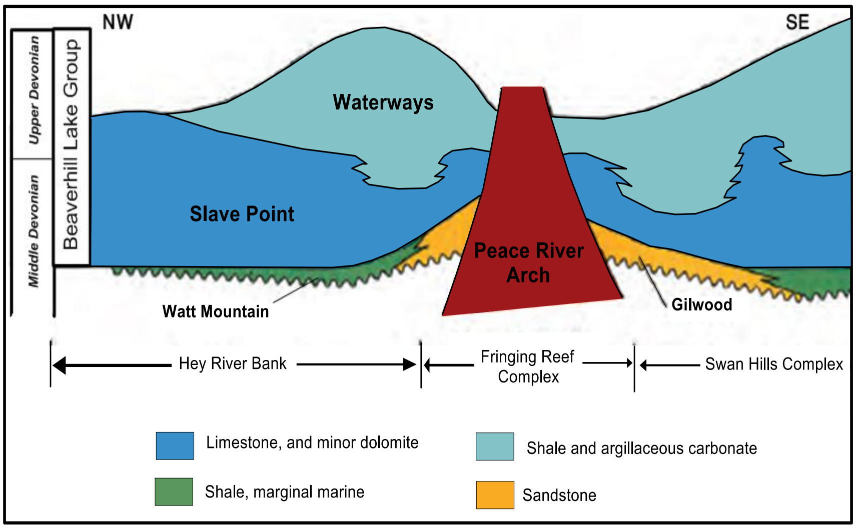

Figure 3: Schematic strata showing the location of the Peace River Arch and the overlying Devonian strata. The bedrock, the bedrock interface, and the Watt Mountain and Gilwood formations are the prime targets for fluid production for geothermal purposes. The Duvernay is stratigraphically above the Beaverhill Lake Group.

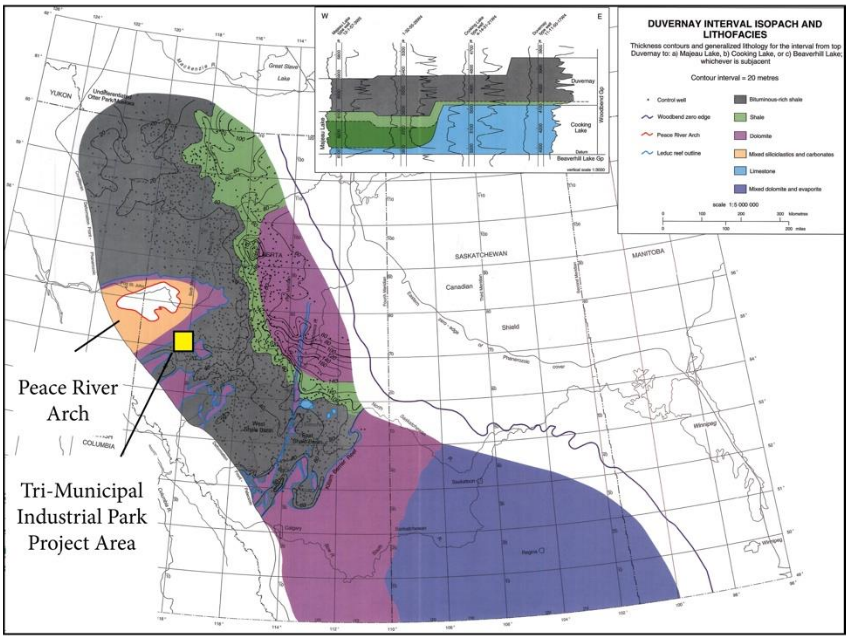

Figure 4: Lithological deposits of the Duvernay Formation overlie much of Alberta. In the area of the TMIP the deposits are tight, hydrocarbon-rich shale suitable for secondary recovery technology (AER 1994).

For geothermal energy production, these younger hydrocarbon-rich formations, made up of shales and dense argillaceous limestones, do not flow quantities of water sufficient for geothermal production. In fact, they are noted as tight formations that require fracturing in order to flow the hydrocarbons. However, they overlie rocks of the Beaverhill Lake Group, which show potential for temperatures and water production sufficient to commercially produce electricity (Banks 2017; Gray et al. 2012; Hickson et al. 2018a, b and c; Majorowicz and Grasby 2010, 2019; Weides and Majorowicz 2014; Weides et al. 2014). High water production from formations above and below the Duvernay are known in the region. An example is the Kaybob Field (to the southeast of the TMIP), where hydrocarbon production is focused on older Devonian-aged strata (Field et al. 1970). Characteristics of the wells drilled to depths below the Duvernay Formation in the project area from 2000-2018 are summarized in Table 1. Unfortunately, the small number of deep wells limits the ability to fully understand temperatures, flow rates, and rock characteristics below the Duvernay Formation.

Table 1: Characteristics of wells in the TMIP drilled below the Duvernay Formation from 2000-2018 area.

Well ID	Well Status	TVD (m)	BHT (ºC)	Formation at Depth	Prod./Inject. Formation	Cumulative Water Inject. (m3)
100/05-18-066-04W6/00	Abandoned	4164	114	Gilwood	-	-
100/05-18-066-04W6/00	Abandoned	4164	114	Gilwood	-	-
100/14-19-066-04W6/00	Active Water Disposal	4046	111	Precambrian	Beaverhill Lake	194,929
100/16-25-066-05W6/00	Cased	3988.8	106	Watt Mountain	-	-
100/06-08-067-05W6/00	Active Water Disposal	3982.4	-	Leduc	Leduc	689,604
100/07-20-067-05W6/00	Active Water Disposal	3661.4	-	Leduc	Leduc	929,140

3.2 Bottomhole Temperatures

BHTs are taken in oil and gas wells when the wells are finished to their target formation and total-drilled (TD) depth. Like geothermal wells, oil and gas wells are drilled with drilling fluid ("mud"). The use of drilling fluids cools the well. For oil and gas wells, there is little to no equilibration time before the BHT is measured. This means that, at best, the BHT is a few degrees cooler than the actual formation temperature, or at worst may be many tens of degrees different. A number of scientists have worked on methodologies (cf. Deming 1989; Gray et al. 2012; Majorowicz and Grasby 2010; Weides and Majorowicz 2014; Weides et al. 2014) to determine the actual BHT in oil and gas field drilled wells. The body of literature points to inconsistencies in the temperature data, data gaps, and in some cases wrongly recorded temperatures, but in other cases tantalizingly consistent high temperatures over a broad area.

The most common method for correcting the BHTs measured in sedimentary aquifers is the Horner Correction. According to Peters and Nelson (2009), the standard deviation of Horner-corrected BHTs is ±8°C in shallow wells, and up to ±30°C in deep formations. In this study, a modification of the Horner Correction method was used by conservatively adding 4-8°C to the measured BHTs according to the depth. 4ºC was added for all depths shallower than 1 km, 5ºC for all depths between 1 km and 2 km, 6ºC for all depths between 2 km and 3 km, 7ºC for all depths between 3 km and 4 km, and finally, 8ºC for all depths 4 km and greater.

There were 431 wells measured from 1956-1999 and 435 wells measured from 2000-2018. For plotting BHTs and creating the temperature gradient plots, the average thermal gradient of each measurement (BHT / (depth in kilometer)) was used. The pre-2000 data shows two distinct gradient populations; 30.3°C/km and 60.1°C/km. According to Gray et al. (2012), digital thermometers became more commonly used in the WCSB post-1999. After this they were widely used to record temperatures through drill-stem tests, though it was not until 2000 that seasonal effects were no longer seen in BHT measurements (Majorowicz pers com. 2018). Therefore, data from 1956-1999 were removed from the analysis. In addition, 38 data points were excluded due to inconsistencies or poor data quality.

3.3 Temperature Gradients

Once the BHT data was cleaned, temperature gradients were calculated for the area. It was immediately apparent that these data showed two different gradients. The filtered and corrected BHT data within the TMIP area from 2000-2018 are shown in. **Error! Reference source not found.**, along with the calculated gradient of 30.7°C/km. Golden Software Grapher 8 software linear power lines "best fit" algorithm was used to calculate the gradients. The three data points from the deep wells helps confirm the higher than global average gradient This gradient was used to plot the formation temperatures at 4000 m (

Figure 6). Based on the calculated gradients, temperatures above 130°C are expected at 4000 m. This depth is also below the Duvernay Formation and within the target formations. These data are considered to be a conservative representation of the temperatures at depth. Until higher temperatures suggested by the older data set are confirmed by testing, these more conservative temperatures were used for development planning.

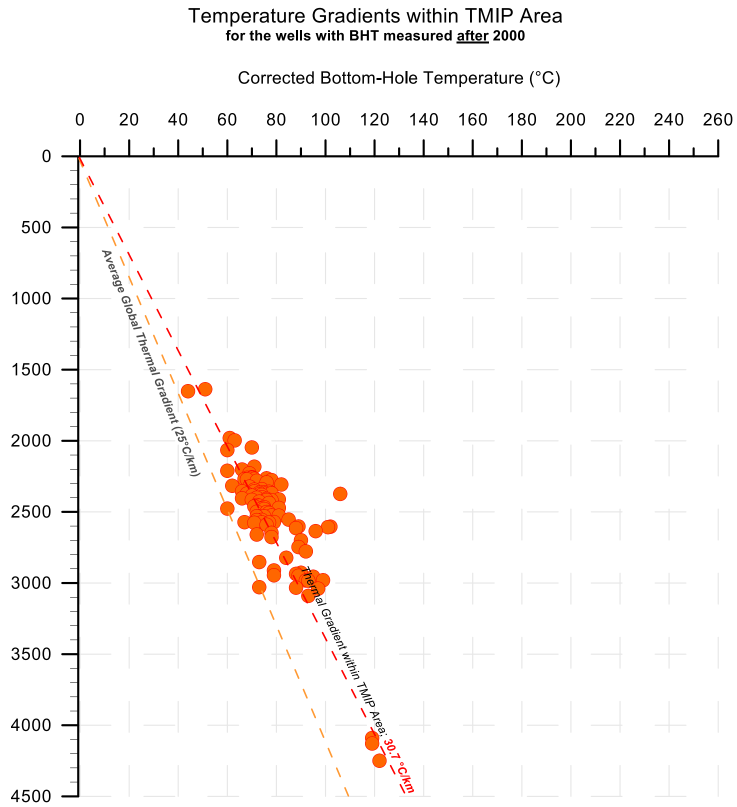

Figure 5: Using only wells in the TMIP area measured from 2000-2018 calculates a gradient of 30.7°C/km (N=104 wells).

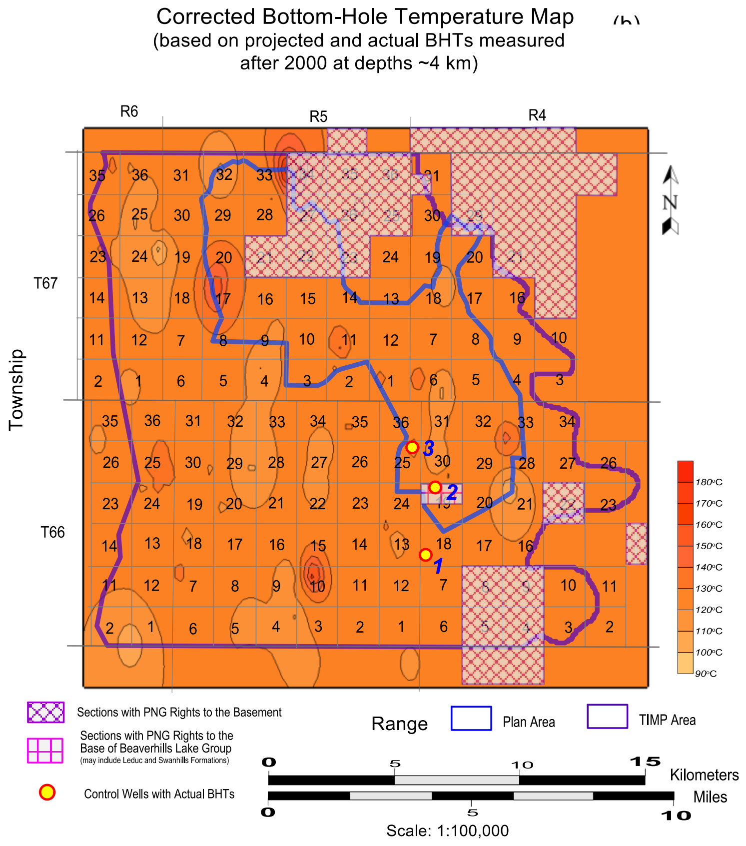

Figure 6: Temperature isothermal contour map of the TMIP plotted using only the post-calendar year-2000 data. The projected temperatures at 4000 m (b) are shown. Numbers refer to wells in control data set.

3.4 Depth-to-Top-of-Formation Map

Each stratigraphic unit has unique characteristics that identifies it from units above and below. In addition to permeability and porosity, these characteristics include contained hydrocarbons and water. The subsurface units are not flat lying as can be ascertained from the distribution of the strata around the Peace River Arch (Figure 3 and Figure 4). Over geological time, uplift and faulting have modified the surface of each unit (Alberta Energy Regulator 2016). As with geothermal wells, when drilling an oil and gas well, rock chip samples (cuttings) and cores are collected and interpreted by the on-site geologist as to the type of rock represented by the cuttings and the stratigraphic unit to which they belong. It is through analysis of these cores and cuttings that a picture of the subsurface can be drawn. The Peace River Arch, geographically evident in the form of the Swan Hills, is an example of an uplifted area where the stratigraphic units thin as they approach the arch due to erosion. By mapping the depth of the top (and bottom) of each unit in the subsurface a contour map of the extent and depth of each rock layer (stratigraphic unit) can be determined (Alberta Energy Regulator 2016). This gives a picture of what the environment of deposition might have been as well as what has happened to the rock unit since its deposition. These are important parameters to understand in order to determine if the rock unit will make a good reservoir rock. In addition to depositional and formational porosity, rocks that have been affected by fractures and faulting can have secondary permeability and porosity.

Figure 7 shows the depth to the Precambrian basement in the area interpreted from 14 deep wells. The wells did not necessarily terminate in basement, but from drilling records basement was likely as the depths were consistent with the Alberta Geological Survey data set. As is evident from the map, the surface dips westward towards the mountain front. In the project area the expected depth to the Precambrian-aged metamorphic bedrock is 3,200 m.a.s.l. or a drilled depth of 3,900 m.

The contour map created for the tops of the formations that underly the Duvernay Formation (Beaver Hill and older) shows a distinct subsidence area in the SE quadrant and overall, the formation dips to the SSW (gets deeper) consistent with the work of Alberta Geological Survey's (2019) 3-D modelling completed for the area. From these types of maps, it is possible to determine if a unit is suddenly terminated, as for example, against a fault, or if the unit is dipping deeper and deeper into the subsurface as can be seen with the data shown in Figure 7**Error! Reference source not found.**. These maps are very important for targeting wells as they help predict where each formation will be encountered in the subsurface when drill site specific information is limited or non-existent.

Other than the Precambrian basement rising to the northeast in the focus region, there is little detailed information as to the subsurface topography due to the limited number of wells drilled to those depths. An analysis of existing seismic and other geophysical data would also help to identify structure and fractures in the subsurface in a similar manner to that done by Alberta Energy Regulator 2016. Micro-seismicity could also be useful to improve the understanding of the subsurface. Fractures are potential conduits for convective heat transfer (Lowell 1975) from deep crustal levels to shallower depth. There is a suggested, but not conclusive, coincidence of wells with high BHTs with regional fractures (Hickson et al. 2018b and 2018c).

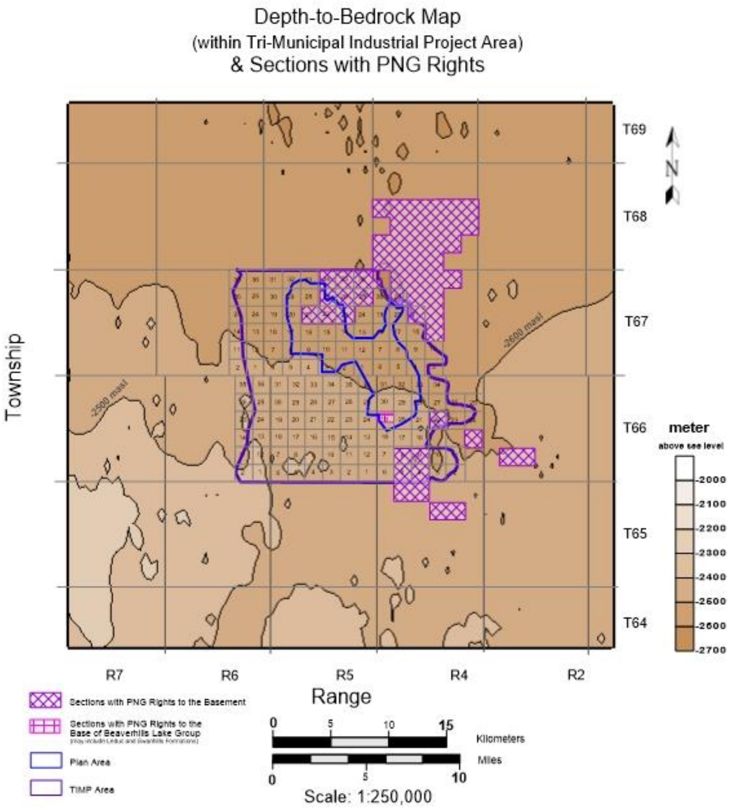

Figure 7: Depth to basement. The map is based on data taken from drilling and geology records available in GeoSCOUT using Golden Software Grapher 8.

3.5 Gross Thickness (Isopach) Map

The thickness of each unit in a well is determined by identifying where the next identifiable unit starts. This information gives the gross thickness of a unit. These unit thicknesses are plotted on a map as an area of equal thickness or isopachs. Figure 8 is an isopach map for the TMIP area and shows the variation in the thickness of the sub-Duvernay Formations. As in oil and gas exploration, a thick resource is preferred in geothermal resource extraction to ensure long-term production from a reservoir.

As already stated, the major oil and gas play in this area is the Duvernay. Other plays have been important at testing the sub-Duvernay strata, but in fact few wells penetrate below the Duvernay in the TMIP area. For this reason, the thicknesses shown in Figure 8 are minimum thicknesses. It is possible that with analysis of seismic data from the area, that the depth to bedrock could be plotted and a better estimate of the sub-Duvernay strata obtained. However, this was beyond the scope of the report. Additionally, detailed analysis of the seismic data may determine if the deep "basin" in the SE quadrant is fault controlled and how it relates to the stratigraphic thickening seen to the NE. It should be noted that this is also coincident with a thickening of the subsurface formations, so could represent a localized basin in the basement, infilled with sediments older than the Duvernay.

In some wells, the Duvernay Formation is absent but when it occurred it is usually overlying the Beaverhill Lake Group. Therefore, the Beaverhill Lake Group was regarded as the top of formations in wells with or without Duvernay. In total, 21 wells drilled the top of the Devonian formations, while none of the wells have hit the target geothermal formations; all have at least one potentially productive formation. The thickness of aquifers underlaying the Duvernay Formation ranges between 100-150 m, but in general, the Devonian Stratum is thick, averaging 700 m. The four potential formations (Leduc, Swan Hills, Granite Wash, Gilwood) have thicknesses that range between 300- 450 m. The Leduc is the thickest formation in this group and has large water flows. Additionally, potential for large water flows from the basement unconformity or even the basement rock is anticipated, but unknown without further exploration and testing

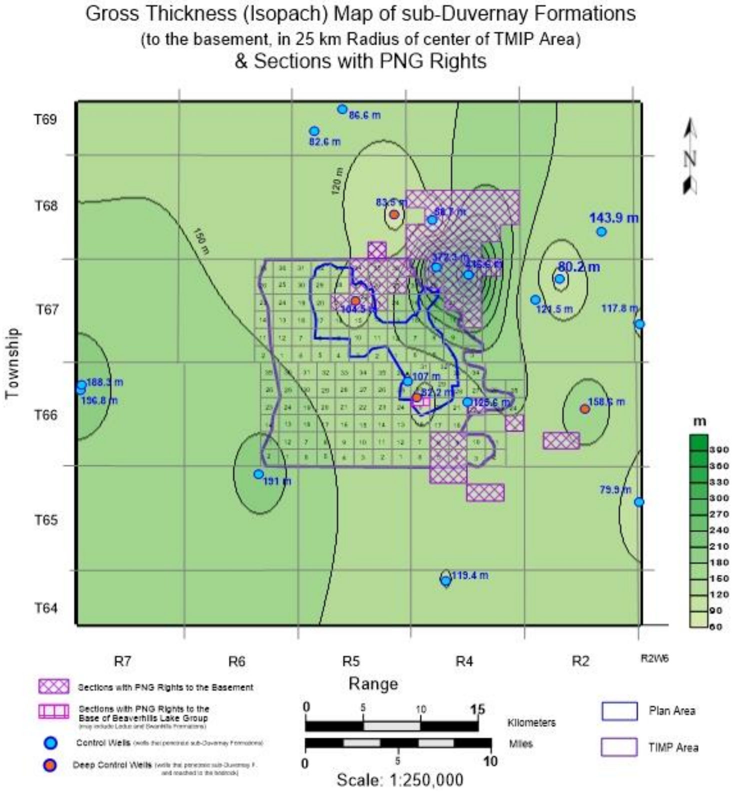

Figure 8: Gross thickness (isopach) map of the sub-Duvernay Formations. The Swan Hills Formation is composed of Pinnacle reefs (Chapman 1983); thus, the consistency of the thickness may not be as indicated. Individual information from each hole has been "smoothed" between data points. Map is based on data taken from drilling and geology records available in GeoSCOUT using Golden Software Grapher 8.

3.6 Porosity and Permeability

In this study, the porosity values are taken from measurements conducted on drill cores (including sidewall cores) in the laboratory, the results of which are accessed through the databases in GeoSCOUT. In some cases, there is additional information gathered from wireline logging of the formations. When no drilling core data is available for the studied wells, logging curves gathered from sonic/neutron measurements can provide helpful indications of relative permeability. Even though the laboratory measurements on drilling cores and logging surveys in the wells had a hydrocarbon reservoir focus, the porosity and permeability values can be regarded as representative of the water-saturated parts of the formation and thus can pertain to geothermal fluids within the formation.

A challenge for the study was that within the TMIP area only three wells have porosity data. These data show the Leduc Formation has an average porosity of 2-10%, but widening the study showed log data for Leduc Formation wells had the potential to be porous up to 20%. The only well that had a porosity log in the mapped area, 100/11-30-066-07W6/00, is located 25 km away from the center of the TMIP area. These results suggest the Leduc Formation could be ranked as high and "good" to "very good" when encountered within the TMIP and the specific project area.

Additionally, from wireline log data outside the TMIP area, the porosity of the Swan Hills Formation is very high and forms a very porous reservoir, particularly at measured depths below 3190 m. Data gathered for the study showed the Swan Hills Formation has an average porosity of 13%, while in some sections it approaches an excellent porosity of 16%. The good porosity, in addition to the formation's thickness and high borehole temperatures, make this formation a good candidate for geothermal fluid production.

In addition to existing studies of the Devonian strata, the log and core data that Terrapin studied confirm that the Leduc and Granite Wash formations can be regarded as excellent target reservoirs Data from outside the TMIP indicate that the highly permeable Swan Hills Formation could also be a suitable target but may not be present in all areas.

3.7 Water Production and Disposal

3.7.1 Water Production and Achievable Brine Flow Rates

As most of the oil and gas pools contain water produced with the hydrocarbon, this produced water can also be a good indicator of the water content of the formation, its permeability, its water productivity, and the flow intensity of the wells. A challenge for geothermal energy production in the TMIP area is the lack of flow tests from the target formations. As noted previously, these formations are deeper and contain less hydrocarbons than overlying formations, such as the Duvernay. Mass flow is a critical factor in economical production of geothermal energy and can be a more important variable than temperature.

A recent publication (Palmer-Wilson et al. 2018) provided detailed analysis of geothermal energy production from British Columbia's portion of the WCSB. In their calculations they showed the viability of projects with the following flow rates: Horn River: 0.0371 kg/s per kW; Clarke Lake: 0.0605 kg/s per kW; Prophet River: 0.0409 kg/s per kW and Jedney: 0.0276 kg/s per kW. They point out that a weakness in the results and their conclusions is the lack of site-specific brine flow data.

In Alberta, work in the Hinton-Edson area yielded similar encouraging results from the Devonian sections. Water recovered mainly from the Leduc Formation in the central region and from the Beaverhill Lake Group in the Edson area yielded flow rates of more than 400 m^3/h (>100 l/s) and a number of wells yielded flows of more than 30 l/s (Lam and Jones 1985). Other studies concerning the sedimentary basin in Alberta have also assumed that a flow rate of 30 kg/s per well might be achievable (Majorowicz and Moore 2014; Majorowicz and Grasby 2014). Another study assessing Clarke Lake and Jedney areas, British Columbia, assumes achievable flow rates of 100 kg/s per production well (Renaud et al. 2018).

Currently the only example of well production measurements in Canada applicable to geothermal development are measurements from the Clarke Lake field in British Columbia. Here the Middle Devonian Slave Point Formation has dolomitized zones that show high permeability. Two gas wells were flow tested by Petro-Canada for approximately a year. The wells produced 2800 m^3/day (33 kg/s) with a deliverability of 0.75 (m3/d)/kPa (Walsh 2013). The Slave Point Formation is part of the Beaverhill Lake Group in the TMIP area, but has not been flow tested, nor has the presence of dolomitization been noted, although few wells penetrate Slave Point Formation so data is limited.

The limited information from the target formations within the TMIP makes it difficult to conclude what flow rates might be achievable, but data cited above from other areas is suggestive of the potential to have flows of sufficient volume to achieve economic success at the expected temperatures of the deeper aquifers. In the case of the TMIP area, as noted above, the BHTs of geothermal production wells are expected to be 120°C or higher at a depth of 4000 m (Figure 6). There is a good possibility of achieving flow rates in the 30 l/s or higher within the TMIP, but only well testing will confirm if these flow rates are achievable.

3.7.2 Water Disposal

In addition to indications of the potential of specific formations to produce water, formations can also take wastewater. The study area contains 29 active wastewater wells, five suspended wastewater wells, and five abandoned wastewater wells in a 50 km radii area around the TMIP area. These wells provide guidance on the best formations to dispose of water.

Of the water wells in the region, three wells are disposing water into Devonian Strata. One well uses the Beaverhill Lake Group and two wells use the Leduc Formation. Other wells are disposing water into shallower formations. Two of the wells inject water at between 3,796 m and 3,989 m depth and the two Leduc formation wells inject approximately 38.5 m^3/hr and 45 m^3/hr, (equivalent to 10.7 l/s and 12.5 l/s respectively, from wells with 7-inch diameter casing with the exception of one well with 5 ½-inch casing).

Two water disposal wells within the TMIP dispose water at 3,796 m and 3,989 m into the Leduc Formation. The geothermal reservoir targets are deeper, (Gilwood and Granite Wash below the Leduc), but these significant water floods must be taken into consideration for their potential to cool the aquifers below. According to Ferguson and Ufondu (2017), water injection may lower the formation temperatures around the injection well for a distance of 800 m.

Water disposal regulations and restrictions mean that disposal capacity is at a premium in the region for many formations, however, in geothermal fields injection is typically back into the producing formation to provide the best pressure support. Once a geothermal field is drilled and testing between wells is possible, the suitability of a well for production, injection or monitoring become obvious and the ultimate fate of the well is known. Significant wastewater disposal will lead to formation waters that are cooler and chemically more mixed than what will be produced from the geothermal target formations. Work will be required to negotiate with the Alberta Energy Regulatory authority to determine if there is disposal capacity in wells in proximity to the geothermal development and ideally into the producing formation.

4. TECHNICAL UNCERTAINTIES

4.1 Hydrogeology of the Formations

Our study has identified several subsurface formations with indications of sufficient porosity and permeability to facilitate the steady flow of water into the well bore. However, even within the same geological formation such as the targeted Granite Wash or Swan Hills Formations, there can be varied permeability based on location. Many interdisciplinary considerations such as fluid chemistry, attributes of the produced fluids, and biological activity of the hydrocarbons needs to be measured and integrated into the analysis. Further in-field studies that verify the permeability and porosity of the target formations prior to exploration drilling are possible if suspended wells can be entered to conduct testing. Once exploration drilling is completed, pressure and injection tests will be carried out.

4.2 Geochemistry of Well Fluids

The chemical makeup of the fluids in the well is extremely important. Downhole fluids with challenging chemistry can cause corrosion, scaling, and gas issues that can quickly create havoc to the infrastructure needed to turn geothermal heat into usable energy. In addition, a major health and safety concern is that many wells in the MDGV produce sour gas (i.e. gas high in hydrogen sulfide (H_2S)). Techniques for the mitigation and prevention of H_2S escape are well-known by the drilling and hydrocarbon industries in Alberta. All steps will be taken to minimize the risk.

A review and analysis of the geochemical properties of the fluids has been completed (Shevalier 2018). This work addressed both the potential for scaling and corrosion from produced brines as well as the impact of injection of the spent brine into the subsurface.

If disposal is considered into the Leduc Formation, the chemistry of the produced fluid will be important to determine any subsurface issues related to mixing of the formation waters. According to the calculations of Shevalier (2018) for the mixing of Swan Hills and Leduc waters the system is initially oversaturated with respect to calcite and remains so during the mixing of the waters. When the Swan Hills and Leduc mixing ratio reaches 12.5% - 87.5% the system becomes oversaturated with respect to dolomite, aragonite, and magnesite. For the Granite Wash - Leduc waters the system is initially oversaturated with respect to calcite. When the Granite Wash - Leduc mixing ratio reaches 10.0% the system becomes undersaturated with respect to calcite. For the Gilwood - Leduc waters the system is initially oversaturated with respect to 4calcite. The system becomes undersaturated with respect to calcite when the mixing ratio reaches 7.5%.

4.3 Fluid Temperature at Wellhead

Although there is data on the BHTs in all the studied formations and for many existing wells, there are no temperature readings at the wellhead on the surface. If the fluid being produced from the wells was pure saline water, then the high heat capacity of water would retain most of the heat from the hot sedimentary basin to the surface. However, in the high-pressure environment within the formations, there are gases that are in liquid state within the downhole fluid. Once this fluid rises to the surface and pressure drops, decompression cooling occurs due to adiabatic expansion of the produced fluid on the way to the surface. Pumping methods which can reduce this pressure drop and the resulting decompression cooling need to be studied. The number of the well bores required is dependent on BHT and flow rates attained and needs to be calculated when more conclusive results are determined.

4.4 Fluid Flow Rates to the Surface

Without conducting additional technical analysis and actually carrying out experiments, it is uncertain as to what flow rates will be found at the surface. Most of the wells are not free-flowing and decompression cooling leads to low wellhead temperatures. In order to overcome the temperature drop, a downhole pump must be used. The small diameter of many oil and gas wells limits the ability to install downhole pumps of the size typically used in the geothermal industry, however some small diameter pumps are available.

Fluid flow rates to the surface have been reported in several papers and vary widely; volumes of up to 100 kg/s from a single well have been reported. Testing of existing wells and purpose-drilled exploration wells will be required before mass flow rates can be determined from the TMIP area.

Additional aspects that must be taken into consideration include the pressure of the formation, estimated withdrawal rates that would be sustainable over a 20- to 30-year period, the type of the pump, the size of pump, and the parasitic load of the pump. The fluid flow rates are a key consideration and input when it comes to fully assessing the electricity generation potential or heat supply from each well. The production rate (l/s) of each well will dictate how and if existing wells can be effectively used to produce geothermal fluids. After review of the existing data, the conclusion was that purpose-drilled geothermal wells will be required in order to harvest the heat energy of the field.

4.5 Reinjection of Production Fluids

Another issue closely linked to the fluid flow rates from the targeted Devonian formations to the surface, is the reinjection of the produced fluids back into the ground for disposal and to maintain pressure within the formation to assist sustainable fluid production to the surface. Many geothermal energy projects in other regions did not reinject their production fluids and eventually experienced major drawdown in fluid flow rates from their production wells due to reduced pressure. However, the quantity of water available within the formations may alleviate the necessity of injecting back into the production formation. Further hydrological testing and modelling will be required.

The total flow rates from the production wells will dictate how many reinjection wells will be needed. With injection experience, collected data suggests that high pressure injection rates in some areas can cause earthquakes and efforts will need to be taken to try and avoid this potential issue.

4.6 Conversion Technology Selection

Once the geothermal resource is better understood through on-site tests and surveys, the final decisions for technology selection for power conversion will need to be made to ensure that the technology selected is the most suitable for the project.

5. EXPLORATION PLANNING AND WELL TARGETING

At the conclusion of the study several priority areas were chosen for further investigations. This process required the analysis and spatial integration of the following information:

1. Predicted temperatures at 3000 to 4000 m depth from post-calendar year 2000 BHT data
2. Depth to sub-Duvernay strata – target is for the shallowest drilling depth
3. Thickness of sub-Duvernay strata – thickest possible sequence of strata
4. Porosity and permeability – these are not available from within the target area
5. Depth to bedrock – shallowest possible depth – depth is not reliable based on 2 data points
6. Predicted flow rates in target formations – highest possible flow rates from sub-Duvernay strata
7. Distance from injection wells – minimum of one km distance from injection well regardless of formation.

Due to the age of the field there have to be deep PNG depleted reservoirs. Drilling deeper than those explored and produced reservoirs will possibly result in encountering drilling problems (lost circulation, sloughing hole, etc.). The drilling histories of the deepest, newest wells will be reviewed prior to developing a drilling program. The locations where multiple favourable indices coincided became the exploration targets. Unfortunately, in the TMIP area not all the favourable indices coincide in one section and the final location was determined by factors related to land position and sub-surface PNG and mineral rights and not strictly geology.

6. CONCLUSIONS

Alberta #1 is poised to change the geothermal landscape in Alberta. Overcoming a number of hurdles and following in the footsteps of DEEP, it is hoped that the project can demonstrate the value of geothermal energy as a transformative industry in Alberta. Base-load power and direct-use applications in the context of a municipally driven and private sector initiative will unlock the industry in Alberta.

The data gathered through the early stage drilling will provide the scientific foundation for the actual flow rates achievable in the target formations as well as the true BHT. Only when the exploration drilling is completed will the commercial value of the resource be known. The project anticipates starting to drill mid-2020. If the first wells are deemed successful following multi-month-long flow tests, production drilling will follow. Generation of power could be as early as 2023.

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