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Geothermal Resource Characterization and Development of the Clarke Lake Gas Field, Fort Nelson, B.C., Canada

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Keywords

Sedimentary Basin, Dolostone, Gas Field, Conceptual Model, Canada

ABSTRACT

The Clarke Lake depleted gas field in northeastern British Columbia displays anomalously high reservoir temperature, high permeability, and a strong water drive, making it suitable to investigate the potential of repurposing the field as a source of geothermal electrical power. The gas field occurs in carbonate sediments of the Slave Point Formation, which were deposited within a rimmed carbonate platform environment flanking the Horn River Basin during Givetian time. The development of porous and permeable reservoir resulted from hydrothermal alteration of parent limestone to dolomite due to the movement of halite- and gypsum-saturated brines through aquifers toward the reef margin. Hydrothermal alteration is common throughout the Keg River, Sulphur Point and Slave Point formations, which constitute the Presqu'ile Barrier, a Devonian carbonate barrier reef extending from northeastern B.C. to Pine Point, NWT. These same formations make up the primary Clarke Lake Reef geothermal reservoir. An initial estimate of the total field-wide potential for electricity generation was found to be 34 MW (Walsh, 2013). An engineering level feasibility study is underway to prove the viability of the geothermal resource for commercial development. The detailed study is being performed of the geothermal resource properties including structure, thickness, permeability, porosity, temperature, brine and gas geochemistry. A three-dimensional conceptual model, analytical well simulations and numerical geothermal reservoir simulations are being created and run to test potential well field designs and estimate power production. A geothermal reservoir characterization well doublet has been designed to prove the resource and support further modeling. Drilling and testing of the doublet wells are proposed for the 3rd and 4th quarter of 2020.

1.0 Project Overview

Clarke Lake is a mature gas field situated approximately 10 km southeast of Fort Nelson, B.C., Canada, Figure 1. The discovery well, Prophet River No. 1, was drilled in the winter of 1957 as a joint venture between Western Natural Gas Company, El Paso Natural Gas Company, Hudson's Bay Oil and Gas Company Limited and Union Oil Company of California (Gray and Kassube, 1963). A prolific Devonian gas pool, Clarke Lake has produced over 52 x 10^9 m^3 (1.83 TCF) of gas, and 49 x 10^9 m^3 (308126 MMbbl) of water since going on stream in January of 1961, Figure 2, (British Columbia Oil and Gas Commission, 2019). Clarke Lake field has largely been depleted of gas and is losing economic value, which affects stakeholders such as field operators and the residents of the Fort Nelson area. Canlin Energy is the last remaining gas producer with a few operating gas wells. Most wells have been watered out and production cannot be economically sustained. The recognition of an anomalously high geothermal gradient and a strong water drive within the permeable hydrothermal dolomite reservoir has led to an interest in repurposing the gas field as a source of geothermal power (Petro-Canada Oil and Gas, 2009; Weides and Majorowicz, 2014). The Fort Nelson First Nation (FNFN) is spearheading an effort to develop the geothermal resources at the Clarke Field. Geothermal leases have been granted by the provincial government. A dedicated geothermal power and direct use system will be developed under a collaboration of the First Nations. Early phase feasibility studies and environmental assessment was completed in the first quarter of 2020. A full-size production well and injection well doublet will be drilled in the 4th quarter of 2020 to prove the geothermal resource and collect data for full well field design. An aggressive schedule puts power on the grid by the end of 2024.

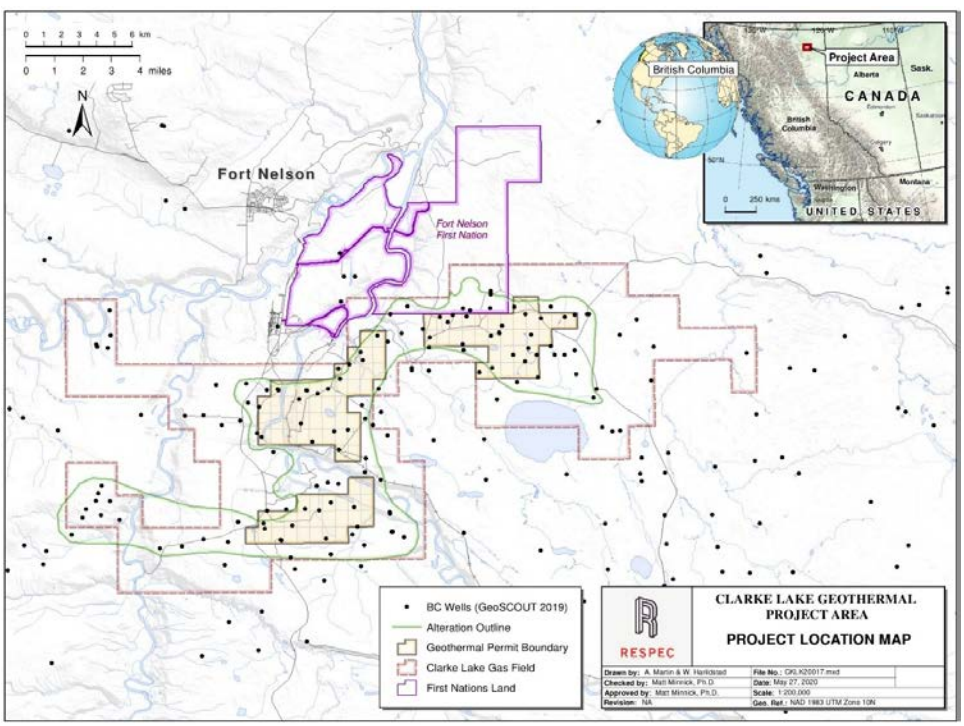

Figure 1. Location map of the Clarke Lake geothermal development project. The Clarke Lake field is on the southern border of the Fort Nelson First Nation reserve land. The map shows extents of the geothermal leases and boundary of high permeability dolomite alteration of the carbonate reef (Alteration Outline).

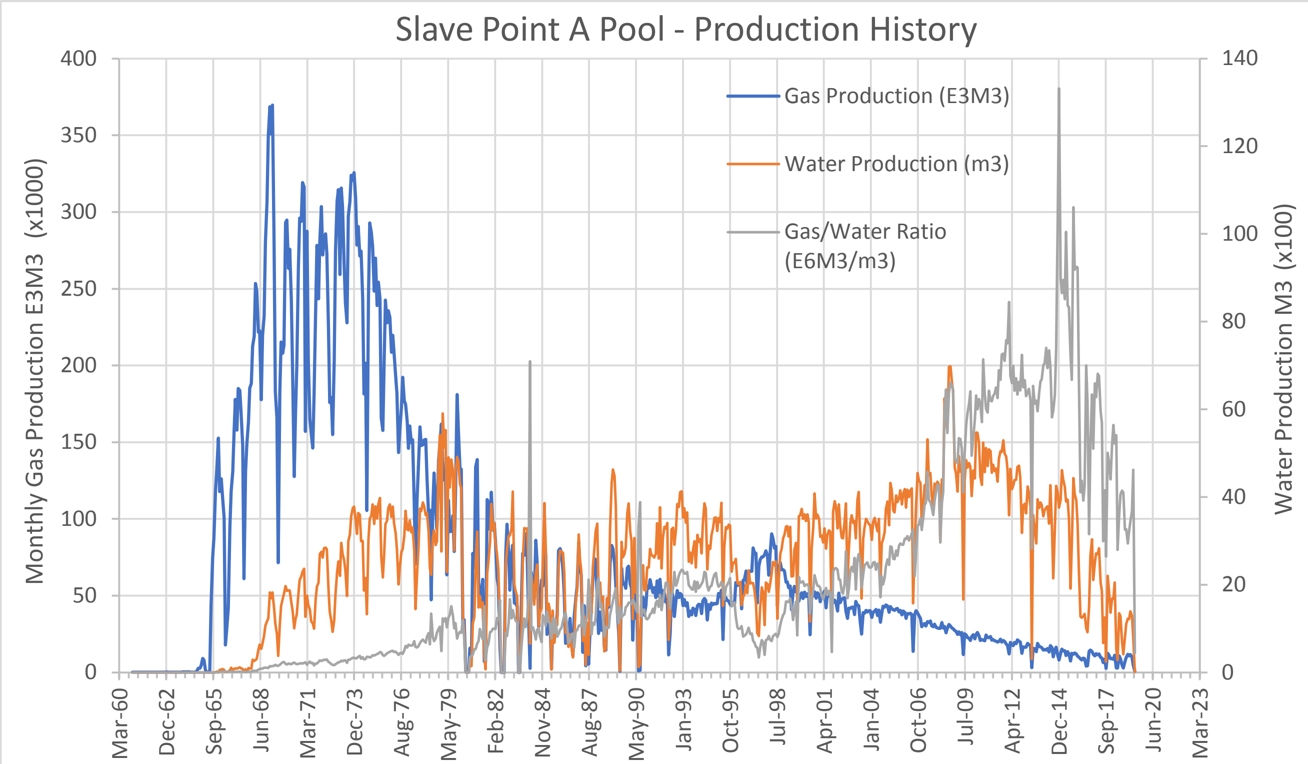

Figure 2. Gas production history for the Clarke Gas field. Initial free gas production from the upper Slave Point reef pinnacles (Attic Gas) tails off in the early eighties. New production wells were drilled up to the mid 2000's keeping gas production relatively stable. Most current active gas wells are now shut-in or watered out.

2. Geology

2.1 Geological History

The Slave Point Formation, along with the Lower Keg River, Upper Keg River, Sulphur Point and Watt Mountain formations comprise a large Middle Devonian barrier reef complex referred to as the Presqu'ile Barrier (Figure 3). Deposition of the barrier began at the end of the Eifelian and persisted until the end of the Givetian. It extends roughly 600 km long from the subsurface near the Rocky Mountains of northeast B.C. to the outcrop edge at Pine Point, Northwest Territories, and the width ranges from 20 to 100 km. The barrier divides the Horn River and Mackenzie shale basins to the north from the Waterways shale basin, Peace River Arch fringing reef complex and the Swan Hills reef complex to the south. In the Devonian, the Presqu'ile Barrier was located at approximately 5° south of the paleoequator within a shallow epicontinental sea favourable for carbonate deposition (Witzke and Heckel, 1988).The oldest Devonian strata unconformably overlie Precambrian or Lower Paleozoic rocks and were deposited within basins adjacent to paleohighlands that include the Tathlina Highland, Fort Nelson Uplift, Western Alberta Ridge and the Peace River Arch (O'Connell et al., 1990). The Tathlina Highland and Fort Nelson Uplift were structural features that existed before deposition of the Presqui'le Barrier and were the loci of reef growth, strongly influencing the stratigraphy and depositional patterns of the Presqu'ile Barrier (Hriskevich, 1967; Meijer Drees, 1994). After a major transgression onto the paleohighlands in the late Eifelian, a continent-wide, regressive carbonate platform comprising deposits of the Lower Keg River Member developed (Meijer Drees, 1994; Morrow et al., 2002). Upper Keg River Formation reefs grew on top of the Lower Keg River Member and restricted seawater circulation to the south, allowing for deposition of evaporites of the Muskeg and Prairie Evaporite formations (Qing and Mountjoy, 1994; Potma et al., 2001).

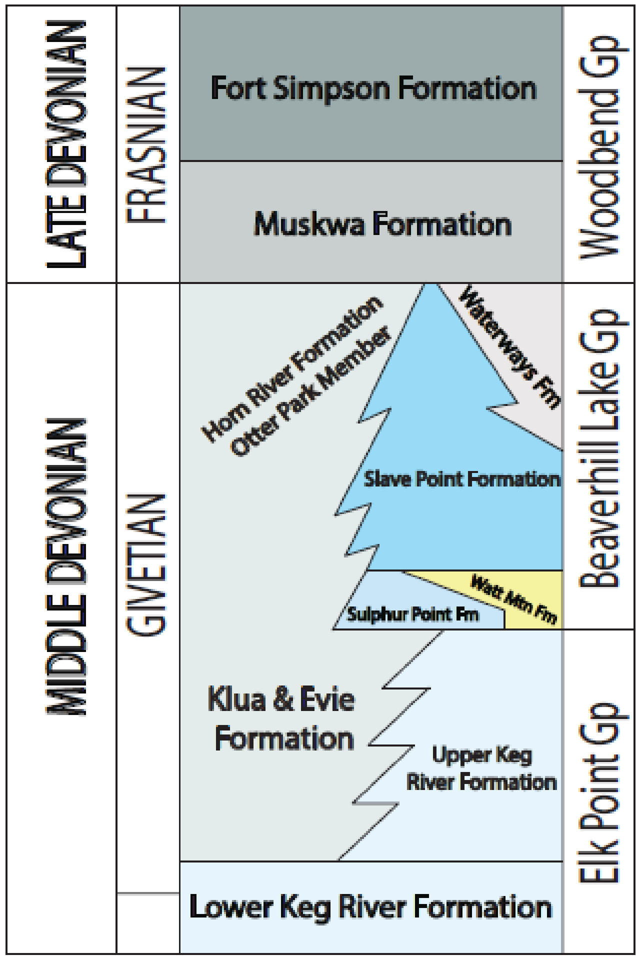

Figure 3. Stratigraphy of Clarke Lake field (Renaud et al., 2020).

In the late Givetian, a rapid sea level rise terminated most reef growth within the Presqu'ile Barrier. Horn River Formation shales and aggradational deposits of the Sulphur Point Formation reflect this final transgression before deposition of the upper Givetian-Frasnian second-order sequence (Fig. 1.3; Potma et al., 2001). The upper Givetian-Frasnian sequence can be subdivided into at least nine third-order sequences, with the Slave Point Formation deposited within the first third-order sequence, termed the Beaverhill Lake Sequence 1. The lowstand portion of Beaverhill Lake Group (and beginning of the Givetian-Frasnian sequence) is first represented by the thin shale of the Watt Mountain Formation; this unit gradually decreases in thickness northward from the platform interior to the Presqu'ile Barrier, where it is absent (Meijer Drees, 1988). The shale sits unconformably above the Sulphur Point Formation and the contact has been interpreted to represent an erosional and/or a transgressive event (Meijer Drees, 1988; Potma et al., 2001; Lonnee and Machel, 2006).

As conditions favourable for carbonate deposition persisted into the Late Devonian, aggradational patch reefs of the Slave Point Formation continued to develop on the Presqu'ile Barrier (Potma et al., 2001). These reefs backstepped as sea level rose until, much like the underlying Keg River, they drowned when reef growth failed to keep up with sea level rise. This major Late Devonian sea level rise resulted in a thick package of Muskwa and Fort Simpson formation shales on top of the reef complex, which provided a regional seal for many Devonian oil and gas plays in Alberta and B.C. (Morrow et al., 2002).

2.2 Clarke Lake Stratigraphy

Geothermal reservoir rock at Clarke Lake consists of several, vertically stacked formations that are predominantly composed of carbonate sediments. Hydrothermal alteration of primary limestone to dolomite is present throughout these formations. The lowermost formation is the Chinchaga Formation, which has been separated into two units, the Upper and Lower (or the Granite Wash Formation). The Granite Wash Formation type section in northwest Alberta consists of anhydite, dolomite, quartz sandstone (with argillaceous and anhydritic cement) and dolomitic shales containing sand at the base (Glass, 1990). In the Clarke Lake region, the Upper Chinchaga consists of *Amphipora* and bulbous stromatoporoid floatstones before shaling out moving north toward the border between British Columbia and Yukon (Madi et al, 2003).

The Keg River Formation can be subdivided into lower and upper members. The Lower Keg River Formation consists of argillaceous, fossiliferous, dense limestone deposited in a relatively deep-water setting. Locally, limestone has been dolomitized and shows vuggy porosity (Glass, 1990). It is also characterized by nodular and wavy-bedded mudstones and wackestones with crinoid, coral and brachiopod bioclasts (Madi et al, 2003). Upper Keg River Formation deposits are represented by stacked cycles that have a shaley base, which grade into higher-energy and coarser grained carbonate deposits at the top (Madi et al, 2003). The Upper Keg River Formation typically consists of boundstones, grainstones and packstones with a bioclast assemblage of stromatoporoids, corals, brachiopods and crinoids. Reservoirs occur in a variety of settings, including platform margin reservoirs, reef buildups along platform embayments, stratigraphic traps and carbonate banks.

The Sulphur Point Formation consists of fossiliferous limestones with interbedded green shales. The bioclast assemblage includes *Amphipora*, *Stachyodes* and coral (Glass, 1990). Sulphur Point Formation limestones are coincident with the edge of the underlying Upper Keg River Formation, and often the two formations share an imperceptible contact. However, Sulphur Point Formation reefs may overstep the Keg River Formation and instead are deposited overtop the Klua Formation (basinal equivalent to the Keg River Formation).

The Slave Point Formation consists of mudstones, packstones and grainstones with a bioclast assemblage that includes Amphipora, Stachyodes, nodular and lamellar stromatoporoids, corals and brachiopods. The Slave Point reef margin at Clarke Lake field has been completely altered to hydrothermal dolomite, whereas reef interior facies show variable dolomitization. This formation forms the main reservoir at Clarke Lake field, with most wells at least penetrating the Slave

Point Formation top. Due to this, reservoir data is predominantly restricted to the Slave Point Formation in the Clarke Lake area.

2.3 Hydrothermal dolomite

Significant secondary porosity observed in dolomite facies is attributed to diagenetic alteration of the host limestone. Intercrystalline pores are rare in dolomite facies, which are mostly occluded by dolomite, fluorite or pyrobitumen. Fracture porosity is commonly observed, where it is partially to fully cemented by dolomite or fluorite and sometimes lined or occluded by pyrobitumen. The dominant pore types in dolomitized and partially dolomitized intervals are mouldic and vuggy. Mouldic and vuggy pores are cemented by coarse, nonplanar-a, planar-s or saddle dolomite crystals or partially cemented by planar-c or saddle dolomite crystals. Planar-s crystals are often seen as cement within ghosts of bioclasts.

The photoelectric log effectively distinguishes dolomite from limestone, yielding values of ~3.0 barns/electron for dolomite and ~5.0 barns/electron for limestone. Increases in resistivity, density porosity, sonic two-way travel time and a decrease in porosity/neutron counts also indicate a transition from dolomite to limestone (Figure 4). Extremely high PE log responses of 6 – 17 barns/electron may be associated with sulphide and fluorite mineralization.

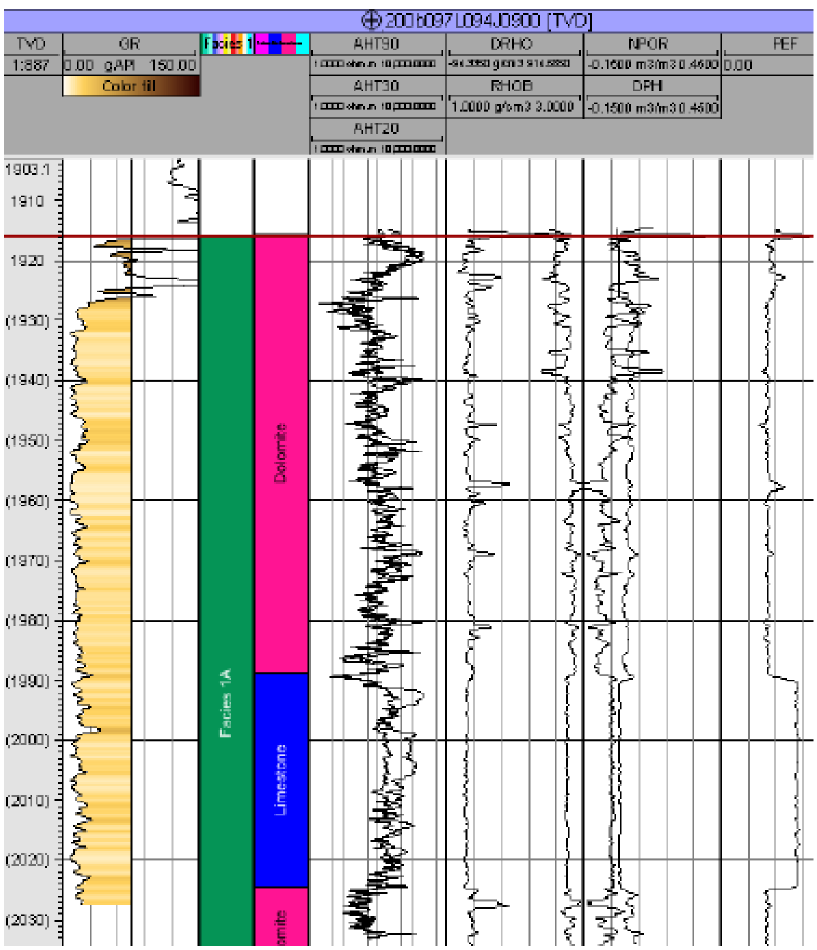

Figure 4. Typical well log responses that differentiate dolomite and limestone intervals (Renaud et al., 2020).

Depositional sequences at Clarke Lake are separated by boundaries corresponding to major flooding surfaces. These flooding surfaces can be correlated from the reef margin into the reef interior and have a variable impact on reservoir compartmentalization, locally controlling the movement of dolomitizing fluid, and thus, the development of dolomitized reservoir rock (Figure 5). Within the reef margin these surfaces exert less control on dolomitization. Instead, dolomitization at the reef margin is primarily controlled by upward movement of brines through depositional facies, the presence of shale permeability barriers or, possibly, the influence of faults.

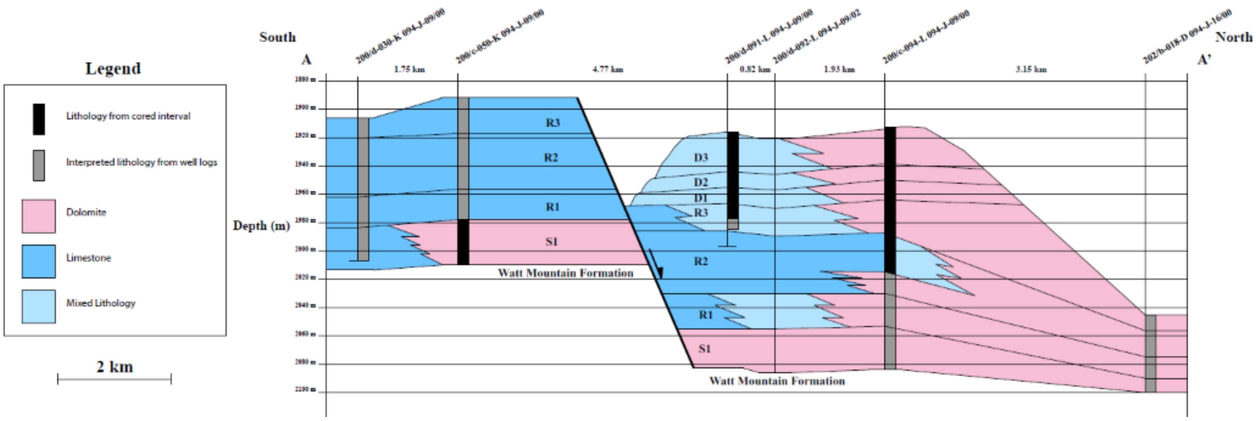

Figure 5. Structural cross-section showing an interpreted fault and the extent of hydrothermal dolomite and depositional surfaces that have constrained the emplacement (Renaud et al., 2020).

2.4 Structurally-controlled hydrothermal dolomite reservoirs

The main reservoir body at Clarke Lake is composed hydrothermal dolomite that altered and replaced original limestone rock fabrics. The presence of dolomite is controlled by original depositional facies and faults. Davies and Smith (2006) emphasizes that faults, fault damage zones and fracture networks are the primary conduits for dolomitizing fluids and the locations of highly permeable hydrothermal dolomite reservoirs. Their recognition can guide exploration for hydrothermal dolomite reservoirs, an approach utilized with success in the discovery of the Ladyfern field along the Hotchkiss Embayment trend in northeast British Columbia and northwest Alberta. The thickest and best reservoir intervals there were directly associated with seismically-resolvable collapse synclines at the intersection of faults (Boreen and Colquhoun, 2001). The fault intersections occur as complex shear faults at oblique angles to a primary deep wrench fault. Interpreted oblique faults (black lines) at Clarke Lake coincident with collapse synclines (white circles) are shown in Figure 6. These faults trend northwest, transecting older, northeast trending wrench faults that are related to the Hay River Shear Zone. Northwest-southeast joint sets identified at Pine Point, NWT are consistent in orientation with faults interpreted at Clarke Lake (Turner and Gal, 2003). Similarly, relationships between hydrothermal alteration and northwest trending faults have been identified in Zama Lake and Rainbow Lake, Alberta (Muir and Dravis, 1992; Lonnee and Al-Aasm, 2000). It is also possible that fluid-conveying faults related to compaction of underlying shale are present, where the Slave Point Formation oversteps the underlying Klua Formation.

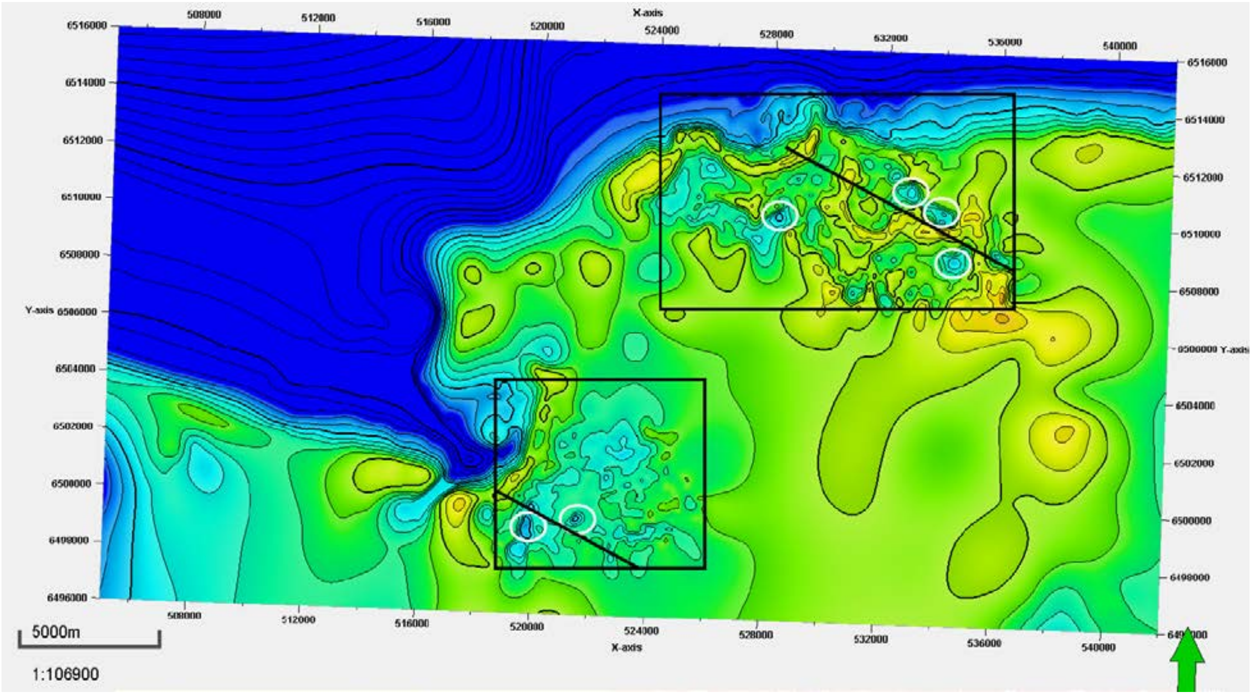

Figure 6. Slave Point Formation structural top map showing structural sags (white circles) and interpreted faults (black lines) within seismically covered area (black boxes).

3. Resource

Early resource estimates using the standard USGS Monte-Carlo heat in place method found Clarke Lake has a mean recoverable thermal energy of 10.1 x 10^{14} kJ ± 3.2 x 10^{14} kJ. An estimate of the mean field-wide generation potential using the same Monte-Carlo approach was determined to be 34 MW ± 10.8 MW (Walsh, 2013). Palmer-Wilson et al. (2018) estimated the mode potential to be 63.2 MW. Preliminary resource estimates conducted under the 2019 feasibility study by the authors indicate the Clarke Lake field will likely support multiple 5 – 10 MWe net binary power plants for a total of 15 – 30 MWe net. The estimates are based on sustainable mass flow rates, production wellhead temperatures, injection temperatures, parasitic loads, and sustainable well field configurations.

3.1 Temperature

A preliminary analysis of historical temperature data was done as a part of the Clarke Lake geothermal project feasibility study. Temperature data sources include bottom hole temperatures (BHTs) from downhole geophysical logs, drill stem tests (DSTs), and absolute open flow potential (AOFP) tests. The temperature data has significant variability because of the data collection methods, reporting discrepancies and timing relative to well completion. No equilibrated temperature logs exist through the target reservoir. To remove the high variability from the existing data, the temperature data were subset and corrected. Data and outliers were removed in a first-pass analysis of the overall reservoir temperature range and spatial distribution. The correction methods used are as follows:

Horner: Used when two or more self-consistent BHTs were recorded in a well. Recorded circulation times were used to bracket lower and upper limits of the temperature correction. The Horner method is the most comprehensive method but was only used on six wells because of the general lack of required data. The temperature gradient was calculated based on the average of the lower and upper temperature limits.

Simple: Used only when one BHT had a recorded circulation time. The method uses a calibrated correlation curve based on Gulf of Mexico sedimentary basin BHT correction curves.

Simple Adjusted: Simple corrections were compared to the Horner method and were found to be approximately 10°C cooler. An adjustment was made to the simple correction by adding 10 C.

Last Resort: Used when no circulation time was available for the BHT. The Last Resort method is a “rule-of-thumb” correction based on a typical 10°–20°C correction found to be applicable in most BHT datasets.

Last Resort Adjusted: The mean value of the Last Resort correction was found to be cooler than other adjustment methods; therefore, an additional 10°C adjustment was added to the data.

AOFP: AOFP tests area used predict gas well performance and design. The AOFP data were not initially adjusted and were found to be the most self-consistent. No standard temperature correction method was found to correct AOFP temperatures. AOFP data can be cooler than the actual reservoir temperature because of several factors, including general wellbore cooling and gas expansion (i.e., the Joules-Thompson effect).

AOFP Adjusted: A conservative adjustment of 4°C was made to the AOFP data to account for cooling. No considerations were made for variability in production tubing size, flow rates, or pressure differentials between the reservoir, production face, and production tubing.

Results from the initial temperature correction exercise are shown in Figures 7, 8, and 9. Figure 7 shows temperature corrections related to depth. Note the spread in corrected temperatures. The temperatures are biased to the altered upper Slave Point Formation because of the gas pool and data collection. Temperature data distributions for the correction methods are shown in Figure 8. Based on the temperature data distributions, reservoir temperatures expected in the upper Slave Point range from 110°–140°C with a median expected temperature of 120°C. Temperature gradients were calculated from the corrected temperature data, as shown in Figure 9. Gradients are used for spatial interpolation to remove depth bias and are considered more reliable for predicting well target location temperature ranges, Figure 10. The geothermal gradient and derived well temperatures assume a conductive temperature distribution which is consistent with the data and regional western Canadian temperature logs. Based on the initial temperature corrections, geothermal gradients are expected to range from 50°–65°C/km. A median temperature gradient of 55°C/km is expected to be representative of the Slave Point. Higher temperatures have been recorded in the Slave Point during DSTs. Several DST tests indicate reservoir temperatures from 143°–152°C. RESPEC is investigating additional regional higher temperature data from BHT logs.

Wellhead temperatures will depend on the temperature of the reservoir fluid and feed zone contribution. Minimal wellbore temperature loss is expected (i.e., < 1°C) given the large-diameter production wells and high flow rates. The reservoir characterization well and future production wells are likely to be completed through the Slave Point and Keg River, and will target additional contributions from higher temperature reservoirs below the Keg River if sufficient permeability is found. Based on the current temperature analysis and expected gradients, a reasonable minimum well temperature of 120°C is expected, and higher temperatures up to 130°C and above could be possible though optimistic.

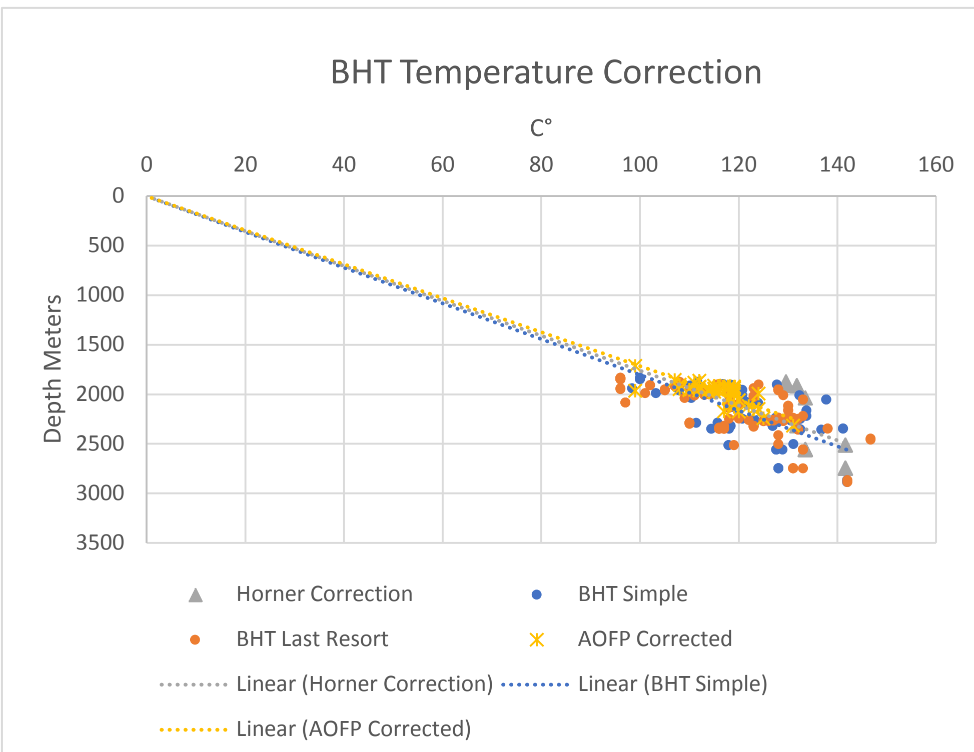

Figure 7. Plot of bottom hole temperature correction results with respect to depth. Plotted simple and last resort points are based on adjusted values as described in the correction methodology assumptions.

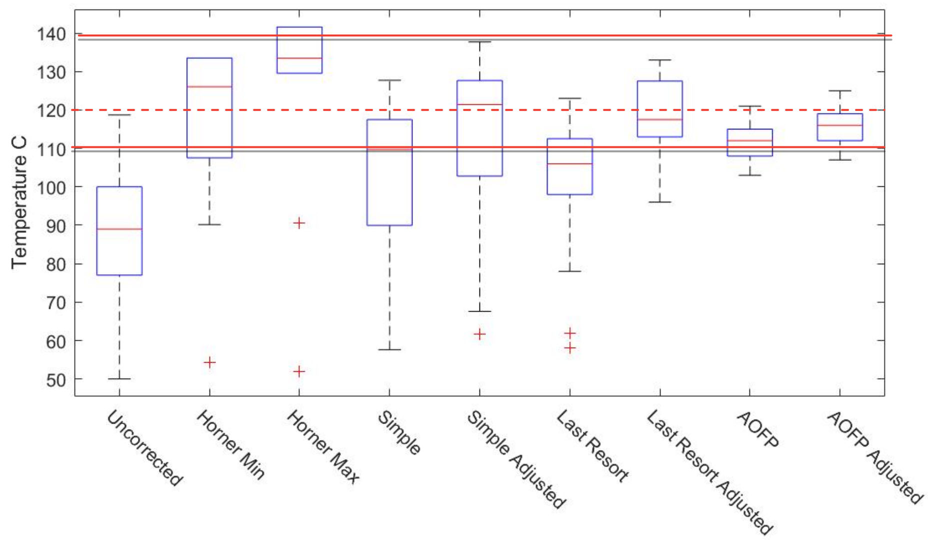

Figure 8. Box plots of temperature distributions per correction methodology. Solid red lines represent the predicted Slave Point reservoir temperatures range, while the dashed line represents the expected minimal well head temperature.

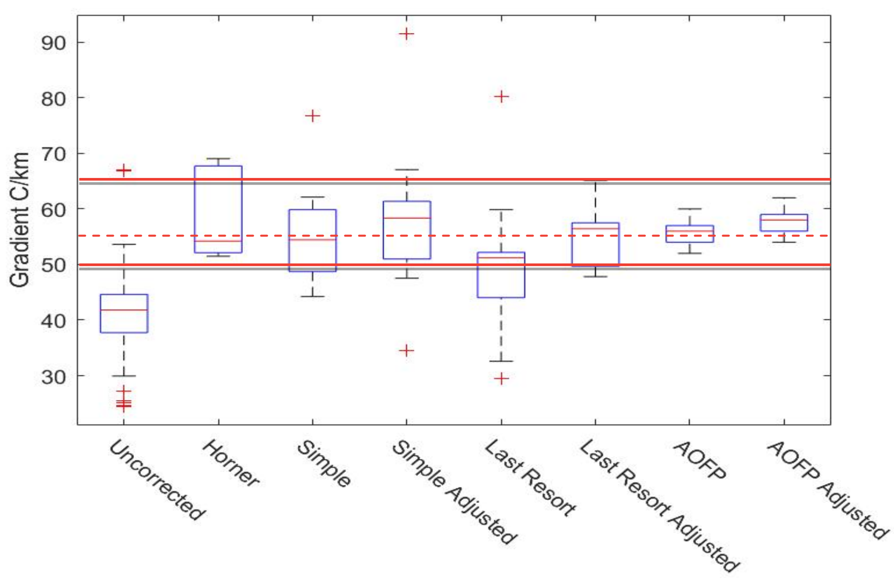

Figure 9. Box plots of geothermal gradients calculated from corrected temperatures per correction method. Solid red lines represent the predicted geothermal gradient range, while the dashed line represents the expected median geothermal gradient.

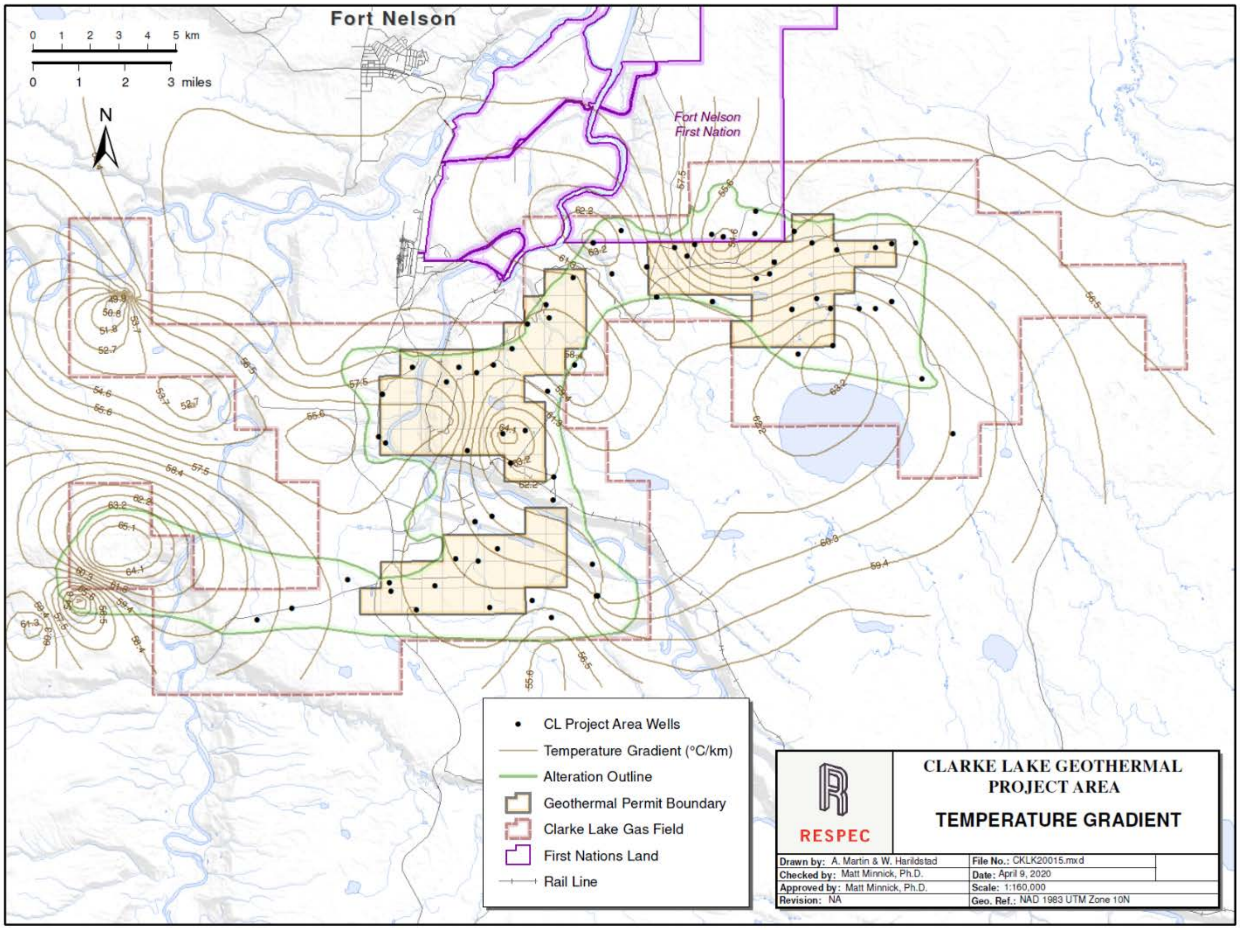

Figure 10. Map of geothermal gradient (C°/km) distribution based on corrected reservoir temperature data.

3.2 Flow Potential

The Clarke Lake field possesses a strong water drive supported by regional flow, West to East, from hydraulically connected reservoirs. The strong water drive was observed in an experiment conducted by Petro-Canada Oil & Gas, who investigated the viability of liberating trapped gas within the Clarke Lake field (Petro-Canada Oil & Gas, 2009). To accomplish this, they attempted to depressurize the reservoir by producing formation water at high rates (2100 - 2800 m^3/day) between January 1st, 2007 and December 29th, 2008, employing two wells as water producers and two wells as water disposal wells. Six remaining wells were designated as gas-lift wells and monitored for pressure changes. Resulting water-gas ratio plots showed no free gas had been liberated because of dewatering. Water production rates at one water producer well peaked at 1800 m^3/day while the volumetric gas to water ratio remained stable at ~3 m^3/m^3. Petro-Canada Oil & Gas speculated that they would need at least a 1 MPa drop in reservoir pressure to access the trapped gas, but at the end of the experiment, static reservoir pressure had dropped by only 100 kPa. Based on well tests, DST's, and logs, a production well productivity index (PI) range of 1.11 m^3/d/kPa to 3.5 m^3/d/kPa would be reasonable. The lower PI was determined from a prior well test conducted by Petro Canada. The upper PI is an estimate based on well logs, drill stem tests (DST's), and core permeability data. The primary reservoir (Slave Point, Sulphur Point, Upper Keg River) ranges in thickness from 220 – 420 meters. Permeability is highly variable and not much is known about additional fracture permeability. A reasonable average permeability range over the full reef thickness is 45 – 140 mD. The permeability thickness range would then be 10 – 60 Dm (Darcy Meters). The secondary reservoir (Lower Keg River, Chinchaga, and Granite Wash Formations) to be explored with the characterization well may add an additional 150 – 250 meters of thickness. Thickness, structure, and permeability of these basal formations are uncertain due to the lack of data. The permeability- porosity is considered to be lower than the primary reef reservoir. Average permeability might range from 5 – 50 md, therefore the secondary reservoir would add an additional permeability thickness of 0.75 – 12.5 Dm. It is important to note that even though the secondary reservoir units may contribute less overall flow to the production stream, the inflow temperatures may be higher. Based on the above data and assumptions it is reasonable to assume the Clarke Lake field will support economic flow mass rates in the range of 80 – 120 kg/sec per well.

3.3 Brine and Gas Geochemistry

Typical chloride reservoir brine total dissolved solids (TDS) ranges from 20,000 – 30,000 mg/l. An example of brine fluid geochemistry is presented in Table 1, taken during the testing of the Carbon Capture Storage research well drilled through the reef in 2010. Both corrosion and scaling will be a factor in development design but based on current data will be manageable. For typical Clarke Lake gas wells the acid gas concentrations are around 2% to 15% CO_2 and 0.4% H_2S. The production well used in the Petro Canada test ranged from 27% - 35% CO_2 and 1% H_2S. The measured pH of the produced water ranged from 6.1 – 6.6. (Petro-Canada Oil & Gas, 2009) Both corrosion and scaling were encountered during the Petro Canada well tests but were within acceptable limits. No free gas is expected to be produced during the resource characterization test. System pressures will be kept at 4 mPa to avoid separation of gas from the produced brine. Samples for brine and gas geochemistry will be taken from a separator configured in parallel with production and injection distribution line.

Table 1. Reservoir brine geochemistry sampled during the Fort Nelson carbon capture storage feasibility well tests (Sorenson, et al. 2014).

Formation: Slave Point	Date Sampled 9-Feb-10
Total Dissolved Solids (TDS), mg/L	26,102
pH	7
Relative Density	1.015
Resistivity, Ω-m	0.247
Barium, mg/L	4
Calcium, mg/L	1722
Carbon, mg/L	60
Chloride, mg/L	15,200
Magnesium, mg/L	152
Manganese, mg/L	1.6
Potassium, mg/L	977
Sodium, mg/L	7726
Strontium, mg/L	102
Sulfur, mg/L	138

3.4 Three-Dimensional Conceptual Model

A three-dimensional (3D) conceptual model of the geothermal resource was created in Earth Volumetric Studios (EVS) by CTECH Development Corporation. The model integrated data contained in an ArcPro Geodatabase from over 100 regional wells and structural interpretation of the top of the Slave Point Formation from two 3D seismic blocks. The model includes over 50 surfaces representing the existing topographic surface to the Precambrian basement. The 3D model is being used for well targeting, stake holder communication, and reservoir geometries for numerical reservoir simulation, Figures 11 and 12. Native 3D EVS files representing the structure, thickness, and rock properties are directly imported into the commercial TOUGH3 numerical reservoir pre-post processor mView by Geofirma Engineering for reservoir simulation.

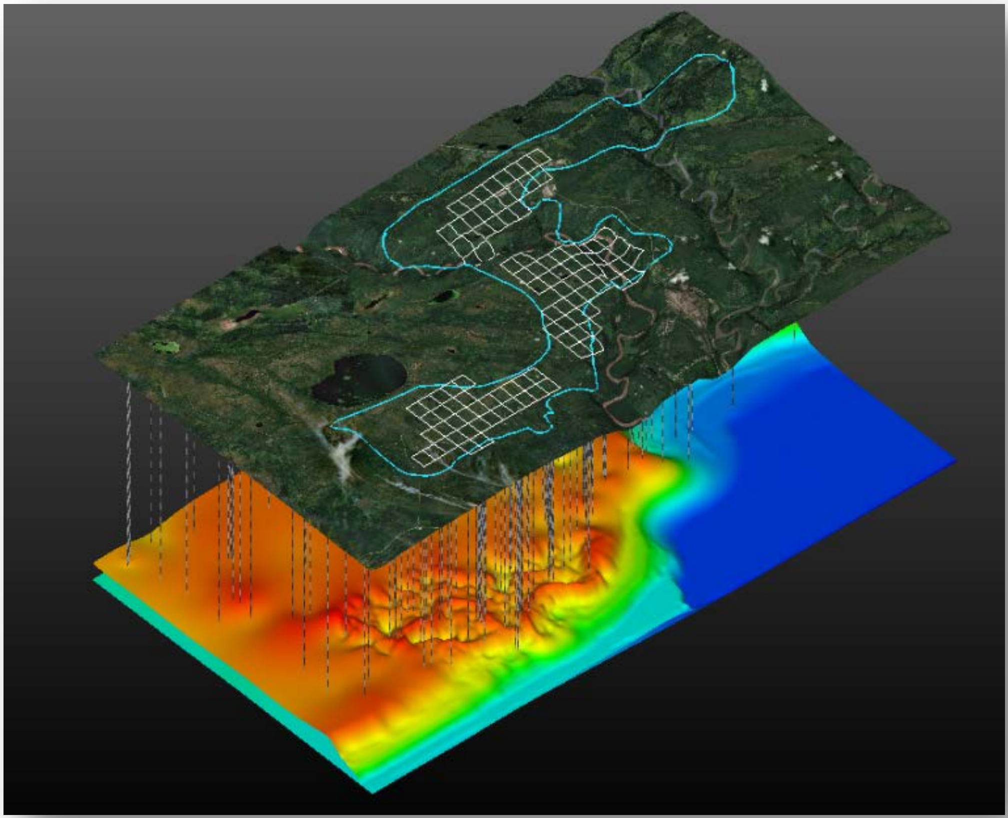

Figure 11. Screen capture of a simplified view of 3D conceptual model representing the topographic surface and structure of the top of the Slave Point Formation (Primary target reservoir).

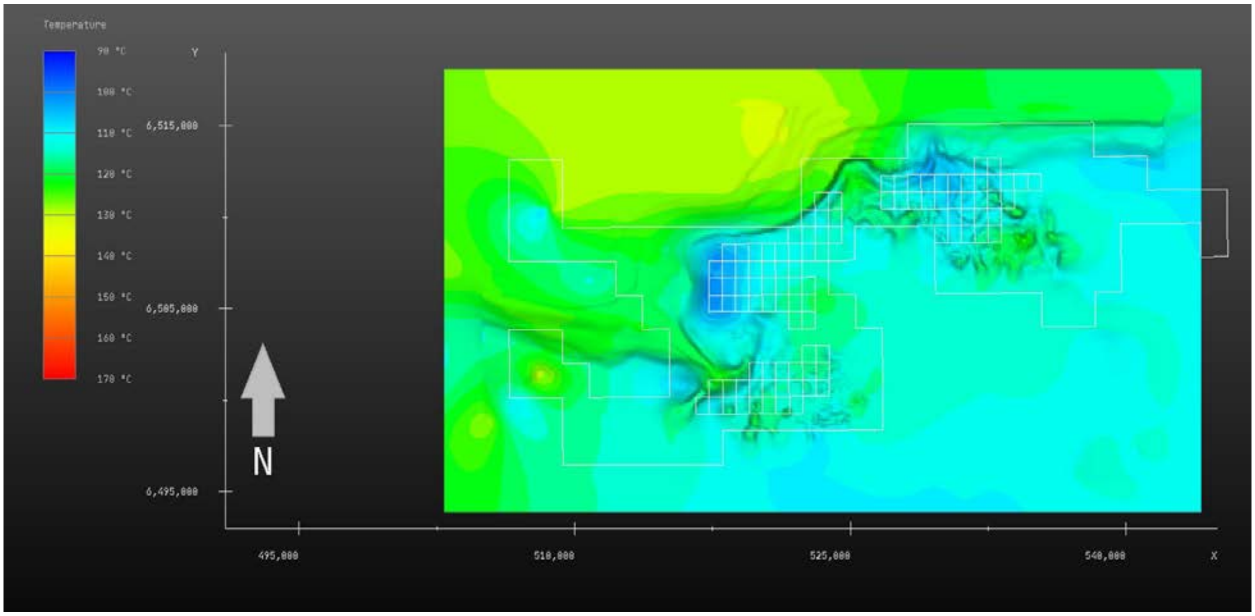

Figure 12. Screen capture from the 3D conceptual model showing the structure of the Slave Point Formation overlain by the dolomite alteration outline and geothermal lease holding.

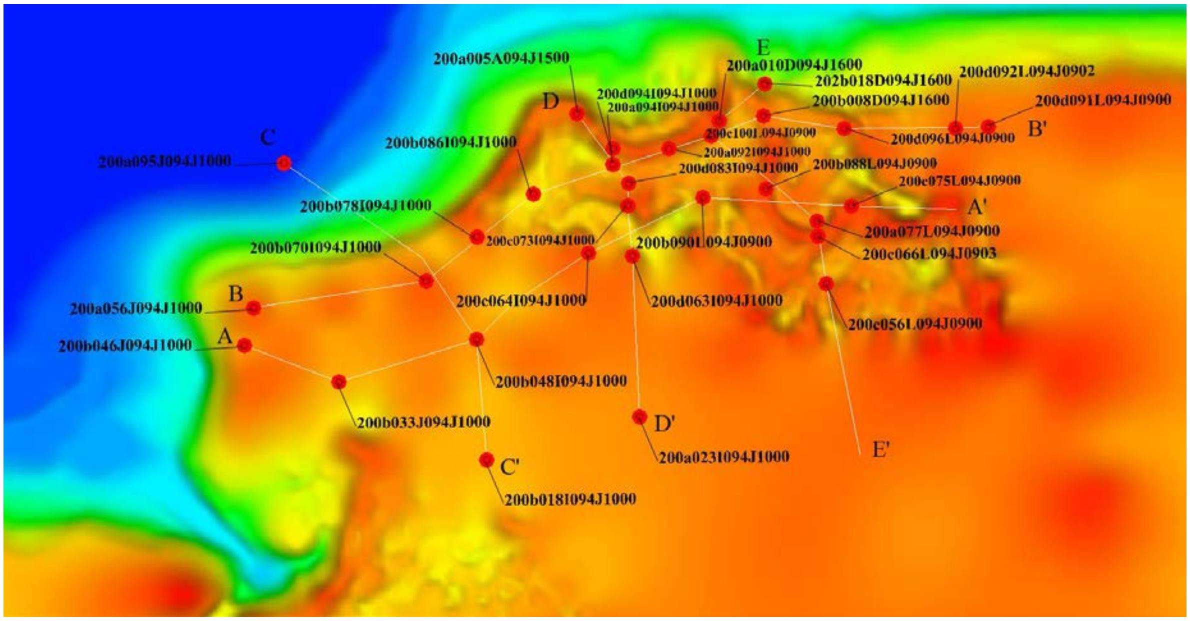

Figure 13. Cross section location map for line B – B' as shown in figure 14. Background layer is structure of the top of the Slave Point Formation (Primary target reservoir).

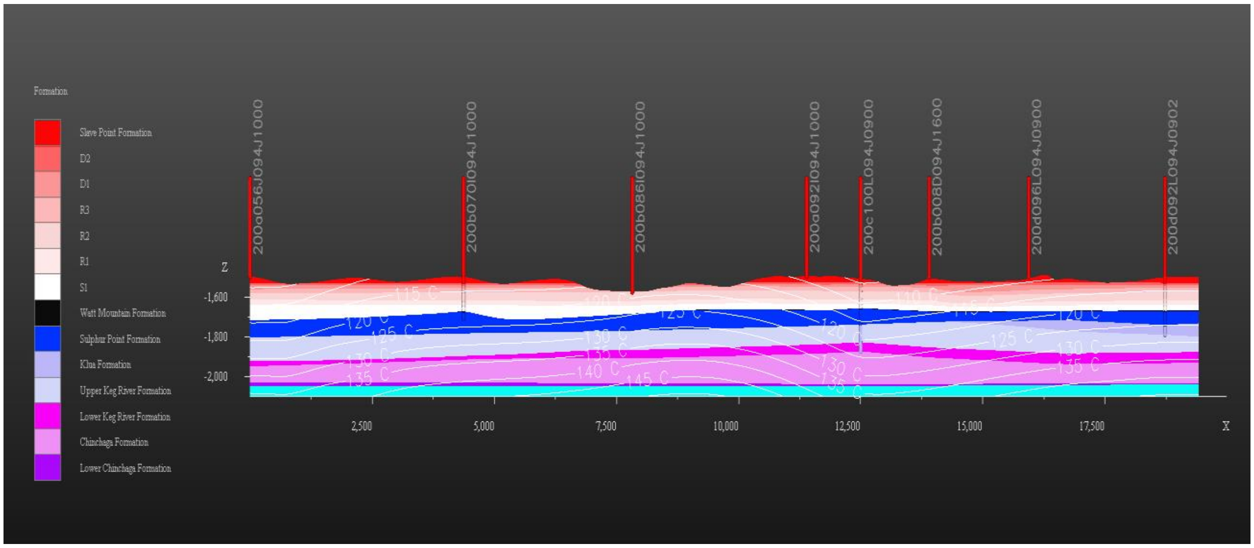

Figure 14. East-West cross-section B-B' showing the primary and secondary reservoir target layers from the Slave Point to the Lower Chinchaga formation. Predicted reservoir temperature contours are mapped to the cross-section surface.

4. Planned Well Test

A full size doublet well test is planned for the 4th quarter of 2020. The objective is to prove the Clarke Lake Geothermal Reservoir as a technically and economically viable geothermal resource for development engineering feasibility and to acquire debt financing for geothermal power plant and well field construction. Additional objectives are as follows.

- Acquire accurate temperature profiles of the Clarke Lake reservoir from the Slave Point to the Precambrian Basement.
- Test reservoir pressure, permeability, porosity and the ability to sustain economic mass flow rates (80 kg/sec – 100 kg/sec +).
- Test Well Deliverability (Productivity Index PI) or Injectivity for Well Field and ESP Design
- Test reservoir brine and gas geochemistry for corrosion, scaling, and engineering design properties.

A dedicated full-size production well will be drilled for the reservoir characterization test. The plan is to directionally drill from an existing shut-in gas well pad to a completion zone with a 300-meter offset from the gas well completion zone. The general well configuration will have a 13 3/8" Intermediate and 9 5/8" production casing to top of Slave Point Formation with an open hole or slotted liner completion. The production well total depth (TD) will be approximately 2500 meters +/- 50 meters, drilled into the top of the Precambrian basement rock. A electric submersiable pump (ESP) will be set in the 13 3/8" casing, intake at 1300 meters depth.

The exising shut-in gas well drilled in 2006 will be converted to an injection well, following well integrity tests. The existing production string will be pulled and the 7" completed gas well will be deepened through the primary reservoir, adding 340 meters to the existing 29 meter open hole to a TD of 2,251 meters, Figure 13. With an assumed conservative productivity index of 1.11 m^3/d/kPa and a tubing pressure of 4 MPa, the ESP performance rate range is 3500 m^3/d - 6000 m^3/d (40 l/s – 69.4 l/s). With a PI of 3.5 m^3/d/kPa, the rate range is 3500 m3/d - 7200 m^3/d (40 l/s – 83 l/s).

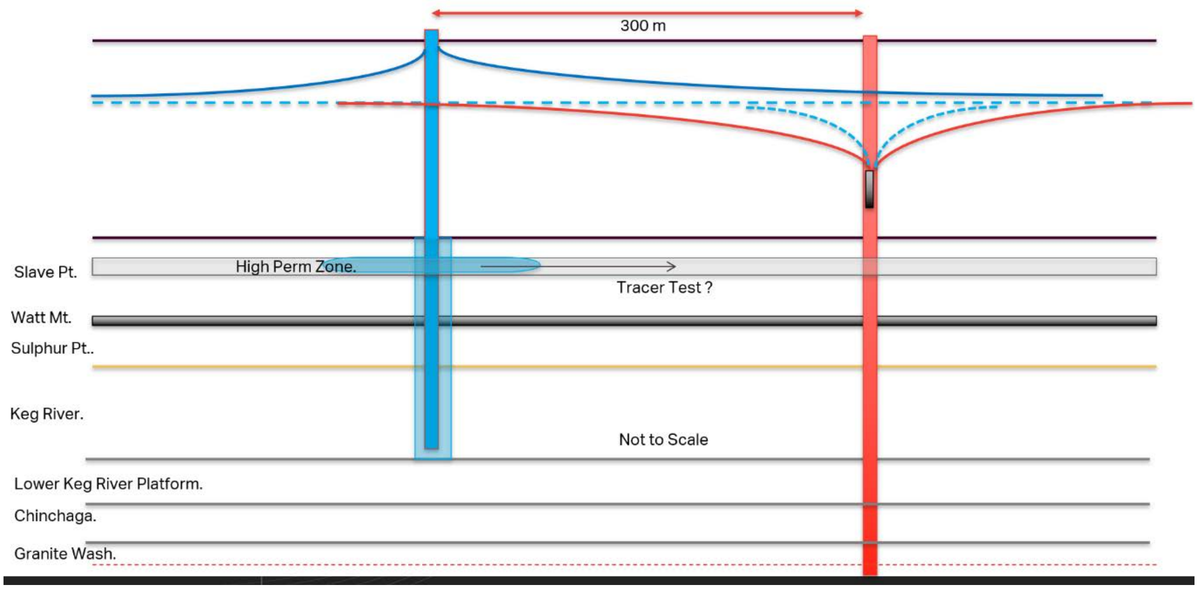

Figure 13. Conceptual diagram of the doublet test configuration. Production well (red) is to completed through the primary and secondary reservoir formatons. Existing gas well (blue)to be converted to an injection well and deepened through the primary reservior. Pressure influence from production and injection at both wells is predicted to be approximately 25% of the pressure change. Static reservoir pressure is predicted to be 14 – 18 mPa.

5.0 Discussion

The Clarke Lake Geothermal Development project is a significant opportunity to repurpose a depleted gas reservoir to stimulate economic growth for the Fort Nelson First Nation. The gas development in the reservoir has provided the data to characterize the geothermal resource and help de-risk early phases of the development project. Based on existing data the resource will support economic power generation and direct use projects. The reservoir is predicted to support mass flow rates between 80 -120 kg/sec with production temperatures of 120 – 130°C. To prove the resource a reservoir characterization doublet will be completed the 4th quarter of 2020. The project stakeholders will acquire the available 3D seismic data that covers the full geothermal lease. The 3D seismic will be analyzed to develop a detailed structural interpolation of all the reservoir target units and basement structure. The data will help define any faulting and basement offsets, qualitative distribution of permeability and porosity trends, and aid in further well targeting and well field development. Development of this important resource is a first step for the First Nations, Province of B.C., and the geothermal community in Canada.

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