Geothermal resource assessment of the Clarke Lake Gas Field, Fort Nelson, British Columbia

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Abstract

Middle Devonian carbonate rocks that host the Clarke Lake Gas Field south of the city of Fort Nelson have long been known to exhibit remarkable permeability and temperatures in excess of 110°C. This permeable dolomite aquifer is controlled by the diagenetic alteration of the original depositional trend of reef facies in the Keg River through Slave Point formations, and is over 200 m at its greatest thickness. A Monte-Carlo model estimate using the Volume Method of the recoverable thermal energy within the aquifer at Clarke Lake indicates the resource is significant in size (mean 10.1×10^{14} kJ; standard deviation 3.2×10^{14} kJ).

Using binary geothermal technology, this thermal energy can be used to generate electricity. It is estimated that purpose-built wells would be able to access enough thermal energy to generate more than 1 MW of electricity each. Geothermal plants could be supplied by multiple directional wells to provide greater capacity than is capable from a single well. The resource assessment indicates that the Clarke Lake field could be used to generate between 12 MW to 74 MW (mean 34 MW; standard deviation 10.8 MW) of electricity.

Résumé

La roche carbonatée du Dévonien moyen qui encaisse les champs gazéifères de Clarke Lake au sud de la ville de Fort Nelson est connue depuis longtemps pour sa remarquable perméabilité avec des températures dépassant 110°C. L'aquifère de dolomie perméable est régi par l'altération diagénétique de l'accrétion sédimentaire d'origine du faciès récifal de Keg River à travers les formations de Slave Point et atteint une épaisseur de 200 m à certains endroits. Au moyen de la méthode de Monte-Carlo utilisant la méthode volumique de l'énergie thermale récupérable à même l'aquifère de Clarke Lake, les résultats probabilistes indiquent que l'ampleur des ressources y est remarquable (moyenne de $10{,}1 \times 10^{14}$ kJ; écart-type de $3{,}2 \times 10^{14}$kJ).

On peut utiliser cette énergie thermale pour produire de l'électricité au moyen de la technologie géothermale binaire. Il est estimé que le forage de puits dans ce but permettrait d'atteindre suffisamment d'énergie thermale pour générer plus d'un million de watts d'électricité avec chacun d'eux. De multiples puits directionnels pourraient alimenter les centrales géothermiques afin de fournir une capacité supérieure à celle fournie par un puits unique. L'estimation de la ressource indique qu'il serait possible d'exploiter les champs de Clarke Lake pour produire de 12 MW à 74 MW (moyenne de 34 MW; écart-type de 10,8 MW) d'électricité.

Michel Ory

Background

Geothermal energy, the heat energy contained within the Earth, can be used for heating and the generation of electricity. It is renewable, baseload, and potentially widespread in British Columbia. Worldwide geothermal energy generation capacity is over 11,000 MW of electricity from 24 countries, with the United States having the largest developed capacity at 3,187 MW (Jennejohn et al., 2012).

Binary geothermal plants use a closed loop heat exchanger to use a geothermal fluid not hot enough to generate steam directly. The geothermal fluid heats a working fluid which flashes to steam at a much lower temperature thereby spinning a turbine (DiPippo, 2012). This technology has been successfully deployed at

BULLETIN OF CANADIAN PETROLEUM GEOLOGY
Volume 61, Number 3
September 2013
Pages 241–251

geothermal plants around the world for thermal resources at temperatures as low as approximately 80°C.

The National Geothermal Energy Program was initiated by the Federal Government in 1976 and terminated in 1986, when petroleum prices fell. Before its termination, this program laid a foundation for geothermal energy development in British Columbia, with exploration throughout the province and a 20 kilowatt demonstration plant at Mount Meager, 72 km northwest of Whistler. Geothermal power generation projects are currently focused on two areas in British Columbia (Mount Meager and Valemount), but substantial investment in British Columbia remains low due to high exploration risk and lack of geoscience data. However, elsewhere in the world, geothermal plants have been cost-competitive with other sources of electricity (GEA, 2012).

In northeast British Columbia, an increase in electrical load growth is forecast because British Columbia's natural gas industry is creating increased demand for electrical power as an option to reduce greenhouse gas emissions. A solution can be found in the high thermal gradient anomalies that have been identified from existing oil and gas well data over the northern region of the Western Canadian Sedimentary Basin. Recently, Grasby et al. (2011) concluded that the Western Canadian Sedimentary Basin contains a very large resource of heat which could primarily be used locally for domestic or industrial heating. Middle Devonian carbonate rocks (Figure 1) host some of the most permeable reservoirs in the Western Canadian Sedimentary Basin (BC MEM, 2003). Where these rocks coincide with high temperatures, there will be potential recoverable thermal resources (Figure 2).

Past studies have identified (but have not attempted to quantify) the thermal energy for use in binary type geothermal plants using the known aquifer system (Johnstone, 1982; Arianpoo, 2009). Johnstone (1982) reviewed the geothermal potential at Clarke Lake; however, the primary technology at the time was based on the flashing of steam directly from the produced fluid. This technology is not viable for low temperature resources such as those at Clarke Lake. New technology warrants a second look at the potential of this field.

The Clarke Lake gas field is eleven kilometers south of Fort Nelson and at an average depth of approximately 2000 m (Figure 3). The Slave Point and underlying Sulphur Point and Keg River formations form a large barrier reef complex (Figures 4 and 5) that marks the transition from the predominantly shale facies of the Horn River Basin to the north and the carbonate facies of the Beaverhill Lake and Upper Elk Point groups to the south (Figure 5). Along the trend of this reef margin, the original (primary) porosity and permeability have controlled dolomitization, resulting in a several kilometre wide zone of pervasive dolomitization (Figure 5) (Lonnee and Machel, 2006; BC MEM, 2003; Oldale and Munday, 1994; Gray and Kassube, 1963). The dolomite trend can exhibit very high porosity and permeability and hosts numerous conventional gas fields (red polygons - Figure 2).

Clarke Lake was discovered in 1957, following the defining of Middle Devonian reef trends associated with the 1947 discovery at Leduc (Janicki, 2008). A total of eight discrete pools within the Middle Devonian are associated with the Clarke Lake Field; however, the Slave Point A is the primary and largest pool within the field with 84 wells (Figure 3). First production was in January of 1961; total cumulative natural gas production is over 51 x 10^9 m^3 (1.8 TCf; current to March 2013) (AccuMap©) (Figure 6). The produced gas contains hydrogen sulphide (0.23%) and carbon dioxide (9.1%). Production values have been in decline since the mid-1970s, with an increasing water-to-gas ratio as the water replaces the gas produced from the reservoir (Figure 6).

A high water drive has supported the reservoir pressure. Between 2005 and 2009, the operator Petro-Canada Oil and Gas attempted to demonstrate the technical viability of depressurizing the reservoir to liberate trapped gas. Down-hole pumps and gas lift technology were employed to increase water production rates which, it was theorized, would decrease reservoir pressure to increase overall production. Water was produced from two wells using down-hole submersible pumps at a maximum combined rate of 2800 m^3/day (33 kg/sec) with high deliverability (0.75 (m^3/d)/kPa – c-91-I/94-J-10/02) (Petro-Canada, 2009). The experiment failed to significantly increase gas production from the pumped wells and subsequent pressure tests indicated that the high permeability of the reservoir had resulted in a lower than anticipated pressure drop (approximately 100 kPa after one year of production) (Petro-Canada, 2009). However, the project provided valuable information about the water production capabilities of the reservoir, viability of downhole pumps, and reuse of natural gas wells for geothermal energy production.

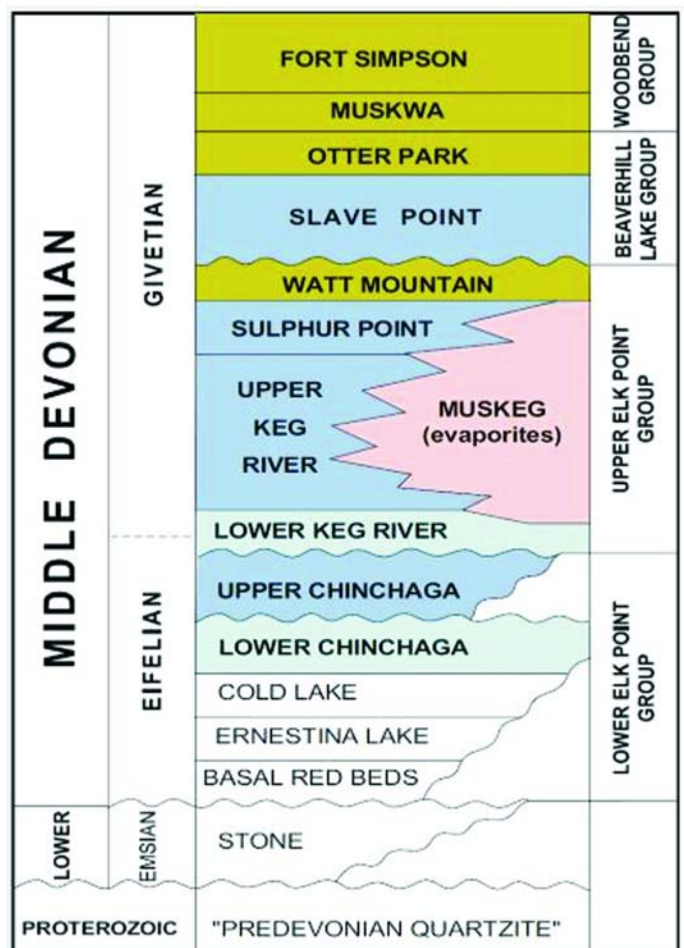

Figure 1. Stratigraphy of the Middle Devonian in Northeast British Columbia (BC MEM, 2003).

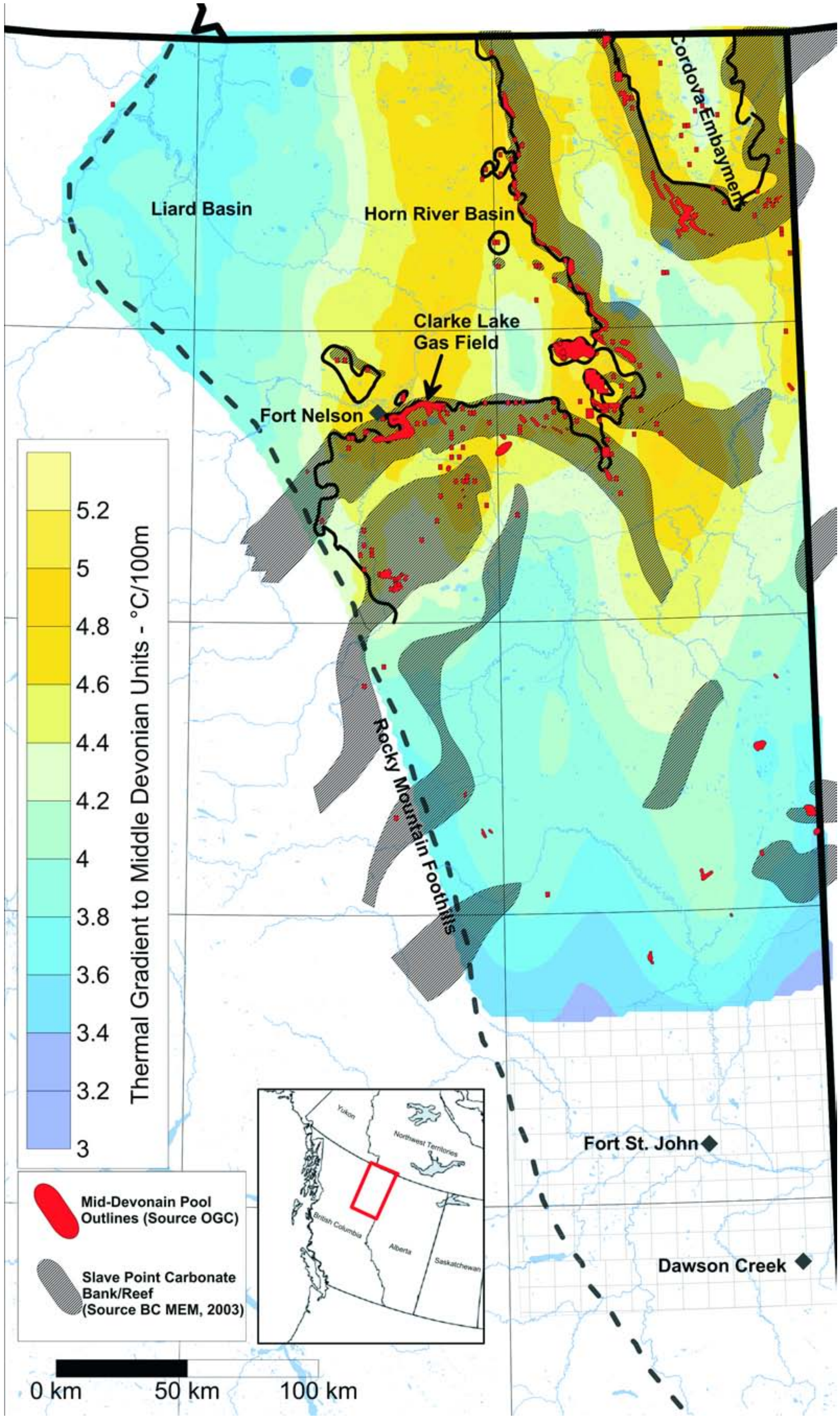

Figure 2. Geothermal gradient (author's own interpretation from various datasets) with indications of permeable Middle Devonian reservoir zones. Cross-hatched polygons are inferred Slave Point carbonate bank/reef zones which host many Middle Devonian gas reservoirs (red polygons) (BC MEM, 2003). These porous and permeable trends could provide extensive geothermal reservoirs.

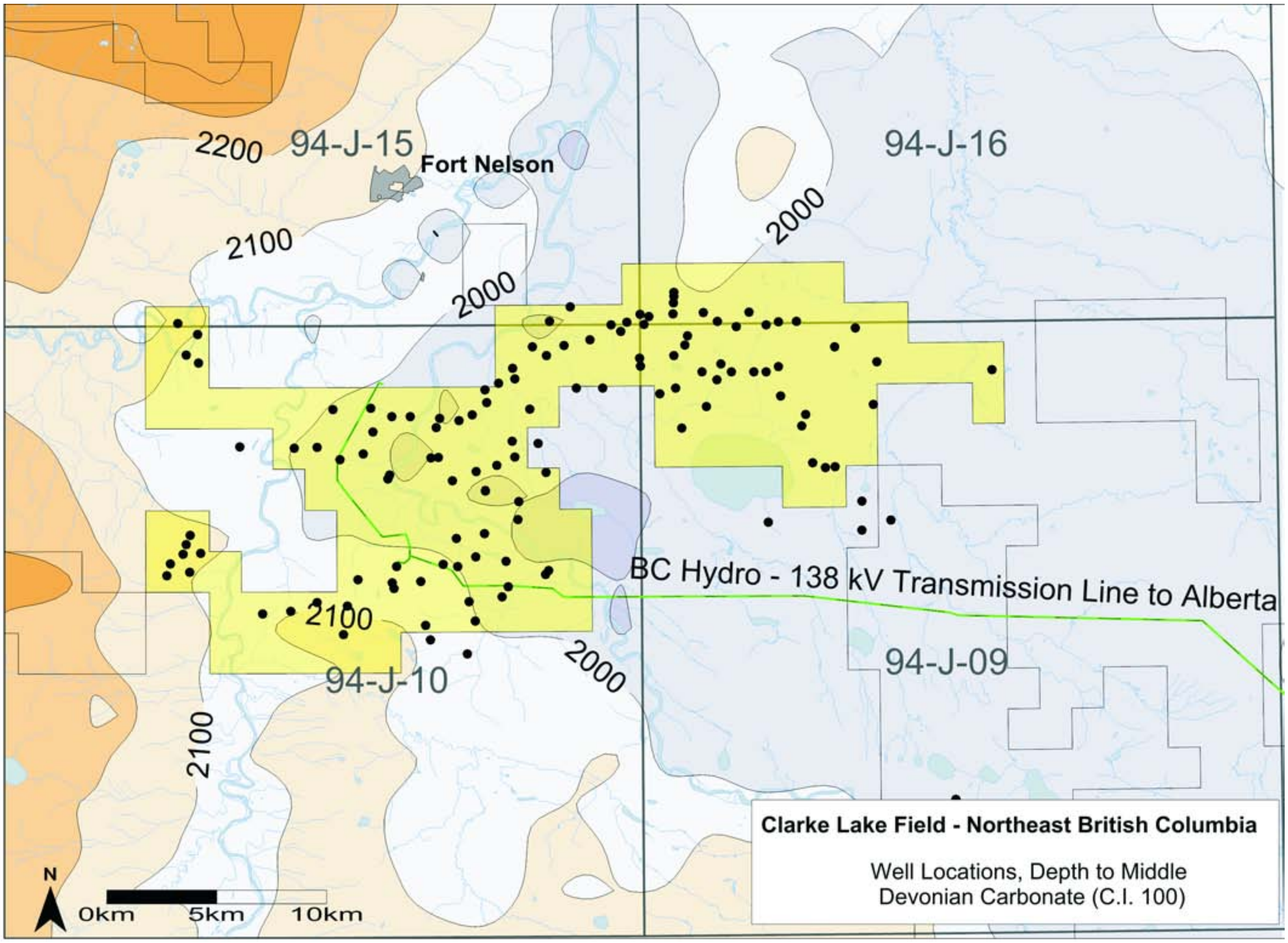

Figure 3. Well locations within the Clarke Lake Field. Contour lines (contour interval 100 m) represent approximate depth to the Middle Devonian carbonate units (Slave Point/Sulphur Point/Keg River) (author's own interpretation from data provided by Lonnee, personal communication). The green line indicates a 138 kV transmission that connects a substation south of Fort Nelson with the Alberta transmission system.

Resource Assessment Methodology

Several models have been published for the assessment of geothermal resources. The Volume Method, which is the primary method used by the United States Geological Survey (USGS) and this study, estimates the total recoverable heat from a geothermal reservoir (Brooks et al., 1978; DiPippo, 2012; Williams, 2007; Williams et al., 2008). To understand the potential of a pilot or small scale development, a further assessment of productivity on a per-well basis was calculated. Finally, to account for uncertainty in the input parameters, Monte-Carlo simulations were run using @Risk 5.0 by Palisade Corporation© within Microsoft Office Excel©.

The volume method estimates the total thermal energy within a reservoir volume (Williams et al., 2008; Williams, 2007). The reservoir thermal energy (q_R) is defined as:

[1] $q_R = pCV(T_R - T_0)$

Where ρ C is the volumetric heat capacity of the reservoir, V is the reservoir volume, T_R is the reservoir temperature. The dead state temperature (T_0) may also be referred to as the rejection temperature and can be approximated by the local average surface temperature. The difference between the reservoir and rejection temperatures is fundamental to understanding the amount of thermal energy available. An estimated recovery factor R_g is then applied to calculate the well head thermal energy (q_{WH}) using the following equation:

[2] $q_{WH} = R_g q_R$

Enthalpy (H) is the total energy content available in the produced geothermal fluid. It is defined by the temperature and pressure of the fluid. In this analysis, it is the difference in enthalpy (ΔH) between the enthalpy at the well head (h_{WH}) and the enthalpy at the dead state temperature (h_0) that is required:

[3] $\Delta H = (h_{WH} - h_0)$

The well head thermal energy is related to mass of fluid produced at the well head (m_{WH}) and the enthalpy of the fluid (ΔH) given:

[4] $q_{WH} = m_{WH} \Delta H$

Exergy (W_A) is the portion of the enthalpy that is available to do work (DiPippo, 2012). Energy that is lost as the fluid changes temperature and pressure is referred to as the Entropy (S). For the purposes of this study, the exergy was calculated for a saturated liquid using the equation:

$$[5]\ \ W_A = \Delta H - T_0 \Delta S$$

Where T_0 is the dead state temperature (rejection temperature) and S is the Entropy. The estimated exergy of the delivered geothermal fluid can then be used to estimate the electrical generation potential using a utilization factor ($\eta \boldsymbol{u}$) (Brooks et al., 1979; Williams et al., 2008):

$$[6]\ \ W_e = W_A \eta_u$$

The energy estimate is in Joules and must be divided by the length of production to determine the potential maximum plant size. This assessment assumes a life-cycle of 30 years.

Model Inputs

Most data inputs within the model are triangular distributions defined by values representing a minimum limit, a mode (or most likely), and a maximum limit.

Reservoir volume is determined from the gross formation thickness and average net porous interval. For the purpose of determining the reservoir volume, two porous interval maps were drawn in addition to the net gas pay map publicly available from the British Columbia Oil and Gas Commission.

The minimum reservoir volume for the distribution is defined by average net gas pay and the area of the Clarke Lake Slave Point A gas pool. Increasing water production history from the field indicates that much of the pay is water filled. To define the most likely value, the total porous interval of the Slave Point Formation was mapped from existing wells to determine the reservoir volume (Figure 7). Maximum values for the model were defined by the combined porous intervals of Slave Point through the Keg River formations. The resulting distribution is presented in Figure 8.

Temperatures recorded during drill stem tests in the immediate region of Clarke Lake range from 81°C to 123°C. Although temperatures may be considered to be more reliable than bottom hole temperatures recorded during geophysical logging runs (Gray et al., 2012), data errors due to equipment and operator errors are common. Gray et al. (2012) use a date cut-off of 1990 for their analysis of hundreds of test data. This is not practical for this analysis, given the limited number of tests available at Clarke Lake. However, temperatures calculated from the depth and approximate geothermal gradient in the region are similar to the reservoir temperature defined by the BC Oil and Gas Commission (2011) (110°C - Clarke Lake Slave Point A pool) which was used as the minimum temperature for the model. The highest temperature recorded during a drill stem test (123°C) was used for the maximum, while 115°C was used for the most likely.

A rejection temperature of 0°C, which is approximately the average annual ambient temperature at Fort Nelson (0.36°C, Environment Canada), was used within the assessment model. A second option would be a reference temperature of 15°C, which is consistent with the methodology of the USGS (Williams et al., 2008; Brooks et al., 1978).

A volumetric heat capacity (ρC) of 2622 kJ/m^{3}K was used in the model, based on estimated heat capacity and density for dolomite.

Recovery factor (R_g) is an estimate of the amount of thermal energy from a reservoir that can be extracted. Several discussions of recovery values are available (Williams, 2007). A range of 0.05 to 0.2 for fractured geothermal reservoirs and 0.1 to 0.25 for sedimentary basin reservoirs are used by the USGS (Williams et al., 2008; Williams, 2007). The Clarke Lake Slave Point A pool is a dolomite reservoir with high permeability and porosity, and likely few barriers to flow. Therefore, a uniform distribution of 0.1 minimum to 0.25 maximum was used for recovery factor within this model.

Utilization efficiency (η_u) is defined as the ratio of actual net plant power to the maximum theoretical power obtainable from the produced geothermal fluid (DiPippo, 2012). Simulation of optimized binary cycles has been performed by Augustine et al. (2009) over a range of temperatures from 100° to 200°C (Figure 9).

A utilization efficiency of 0.18 corresponding to the minimum temperature of 110°C was used in the assessment model for the Clarke Lake reservoir. An option for refinement of future models is to relate the utilization efficiency to estimated temperature for each simulation.

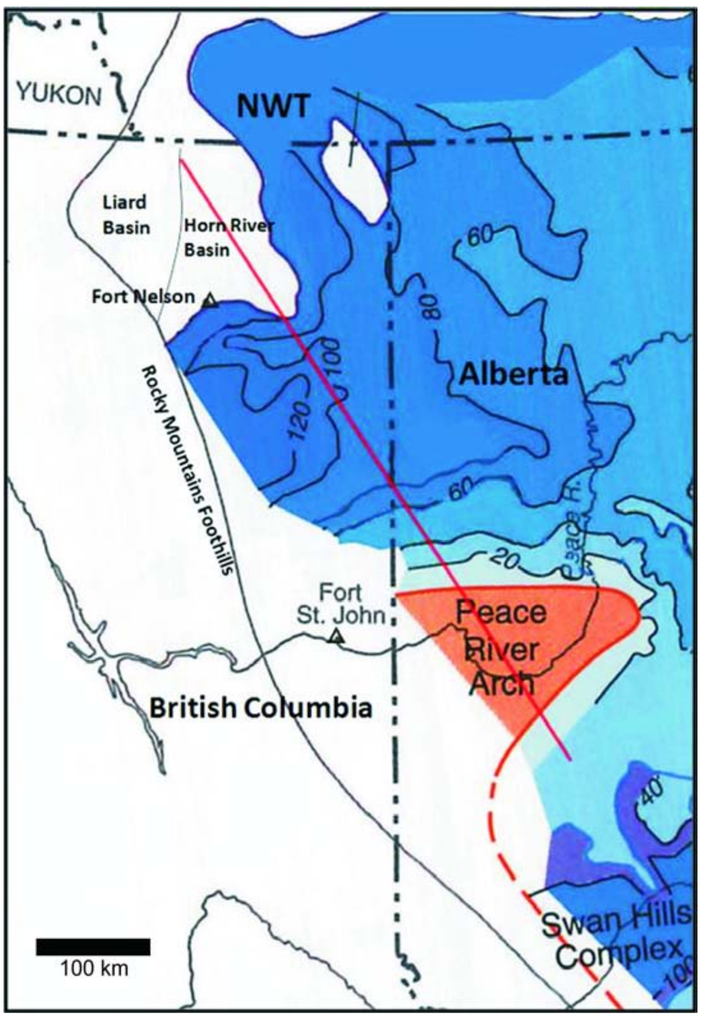

Figure 4. Regional paleogeopgraphy and isopach in metres of the Beaverhill Lake Group. Red line indicates approximate location of representative cross-section in Figure 5. (Modified from Oldale and Munday, 1994.)

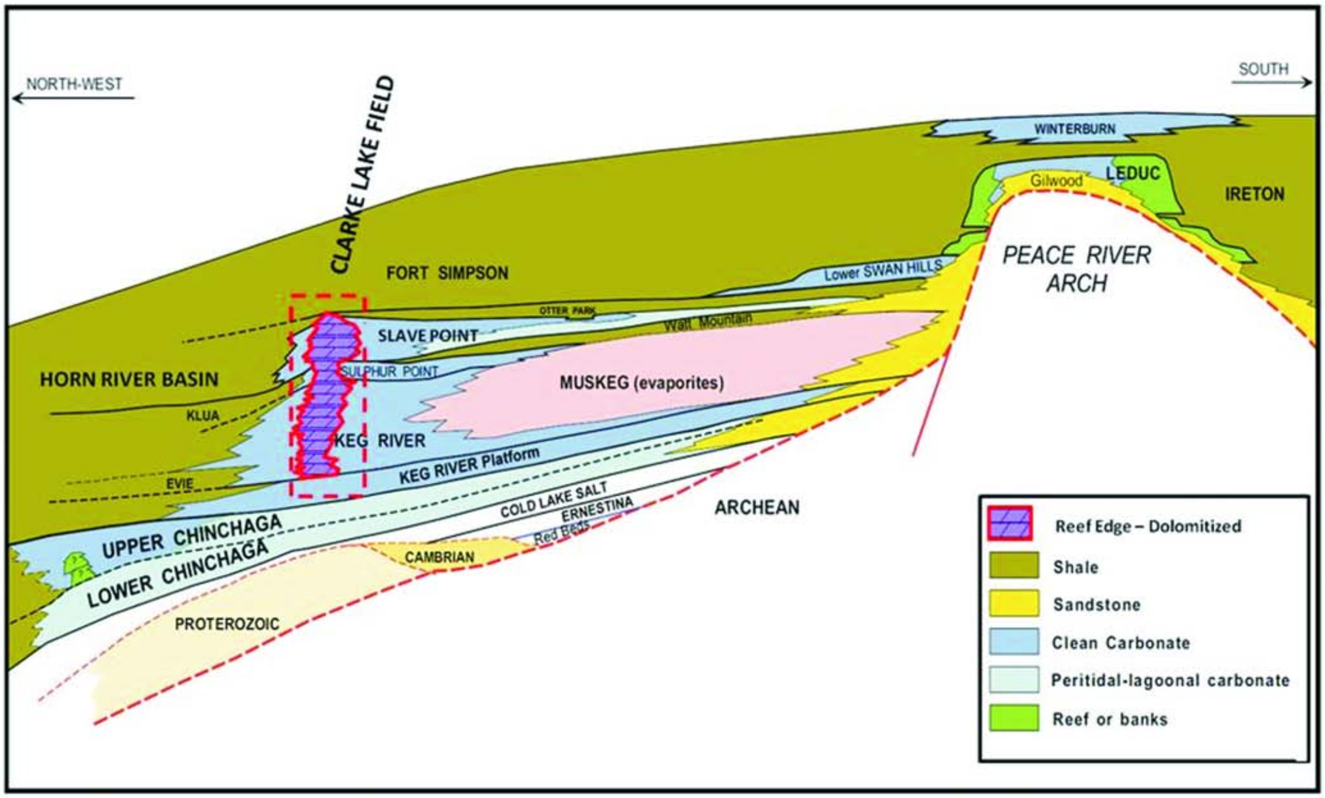

Figure 5. Regional cross-section porous/permeable zone of dolomite is associated with the original reef or bank edge at Clarke Lake. See Figure 4 for location of the cross-section. (Modified from BC MEM, 2003.)

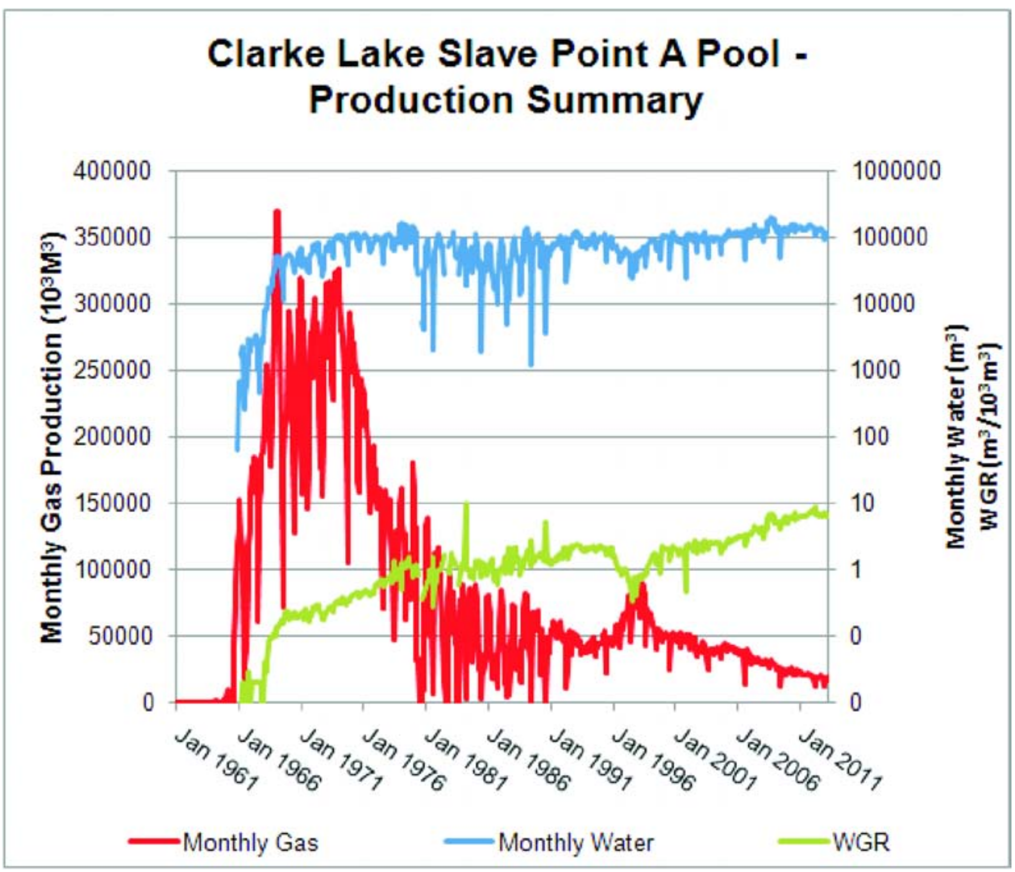

Figure 6. Clarke Lake Slave Point A pool production summary (AccuMap©). Red line is monthly gas produced (10^3m^3); Blue line is the total daily water production from the field (m^3/d); Green line is a calculated water to gas ratio ($m^3/10^3m^3$). The water to gas ratio (WGR) has increased throughout the life of the pool as a result of declining gas production.

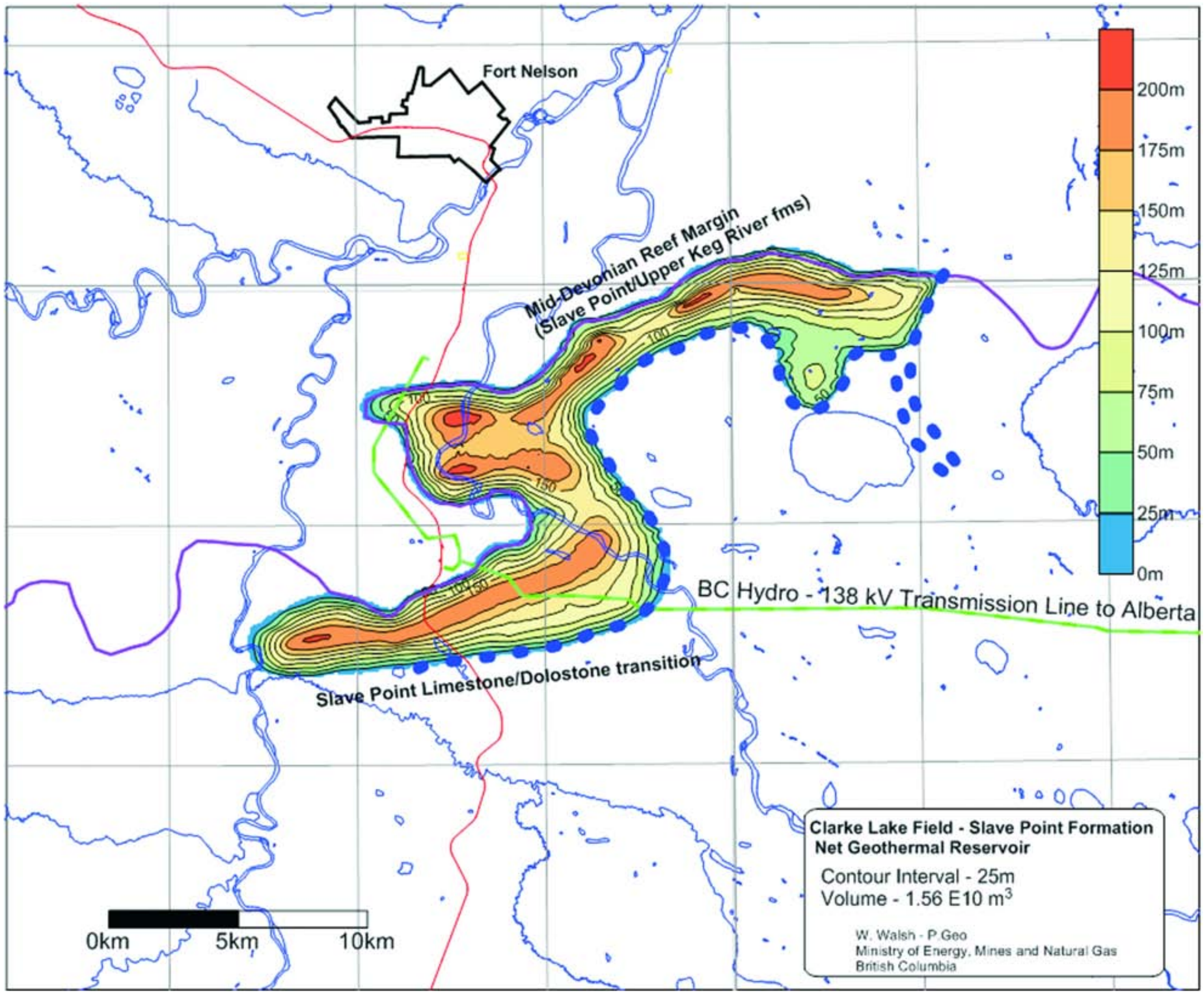

Figure 7. Clarke Lake field Slave Point Net Geothermal Reservoir (contour interval 25 m). The reservoir zone is bounded to the north by the depositional transition to shale of the Horn River Basin (purple line); to the south the reservoir is defined by a transition from dolostone to non-reservoir limestone.

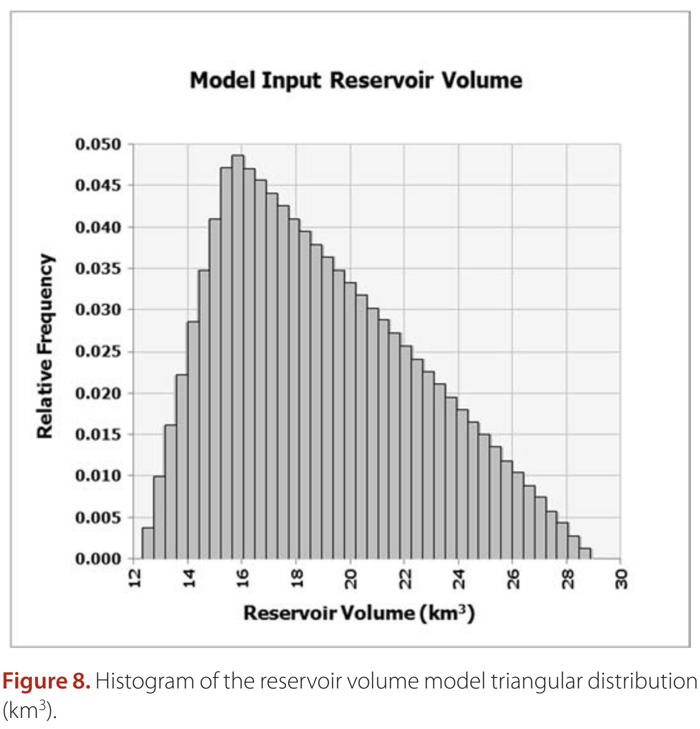

Figure 8. Histogram of the reservoir volume model triangular distribution (km^3).

Results

The Clarke Lake Field is a well-documented gas field; as such, there is considerable well control, temperature and flow data. Based on the data available, this description of the Clarke Lake Field is considered a "Measured Resource" under the geothermal reporting codes (Beardsmore et al., 2010; Diebert and Toohey, 2010).

The inputs as described above were used to estimate the well head thermal energy (q_{WH}) using equations 1 through 3. A Monte-Carlo simulation of 10,000 iterations provides a probability distribution from the input ranges. Figure 10 is a graphical output of the simulation. The mean of the distribution was 10.1 x 10^{14} kJ with a standard deviation of 3.2 x 10^{14} kJ and a range of 3.8 x 10^{14} to 21.5 x 10^{14} kJ.

The Monte-Carlo simulation also determines the generation capacity using equations 4 through 6. The distribution estimate of potential electrical generation from the Clarke Lake reservoir is presented in Figure 11. The mean derived by the model was 34 MW with a standard deviation of 10.8 MW. The range of the output was between approximately 12 MW to 74 MW.

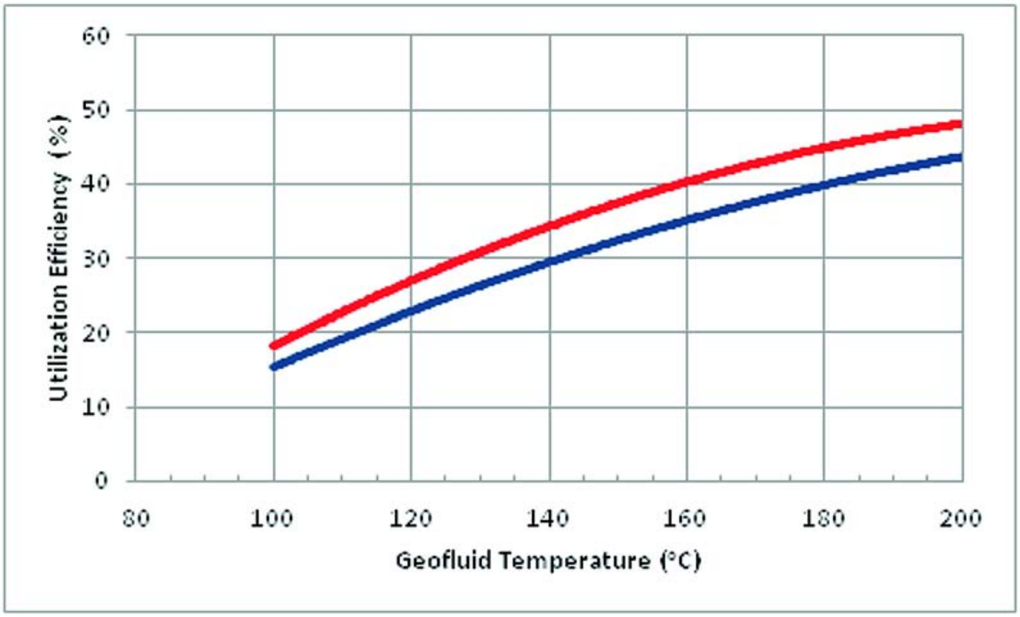

Figure 9. Utilization efficiency as a function of geothermal fluid from Augustine et al. (2009). Red line is for supercritical pressure cycles; blue line is for subcritical pressure cycles. A utilization efficiency of 18% was used in this study corresponding to the minimum expected geothermal fluid temperature of 110°C using a subcritical Rankine cycle. The higher efficiency supercritical cycle is similar but uses a pump to pressurize the working fluid.

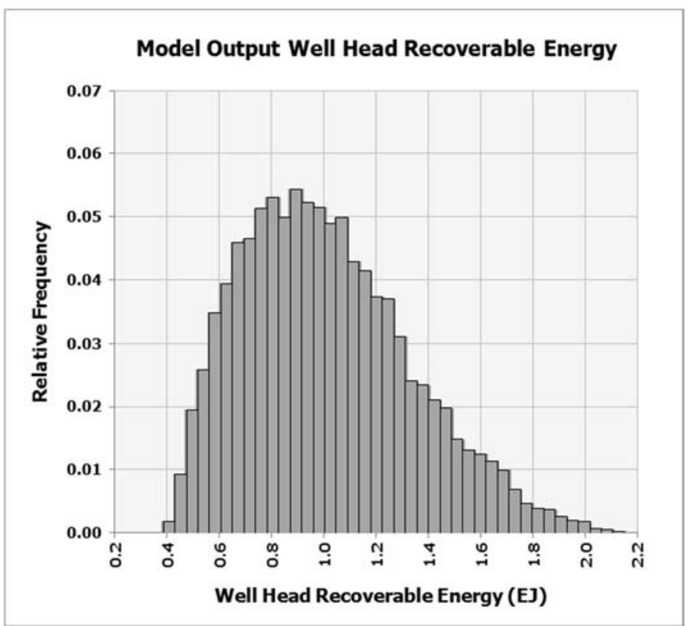

Figure 10. Histogram of the well head recoverable thermal energy model output (q_{WH}) (kJ).

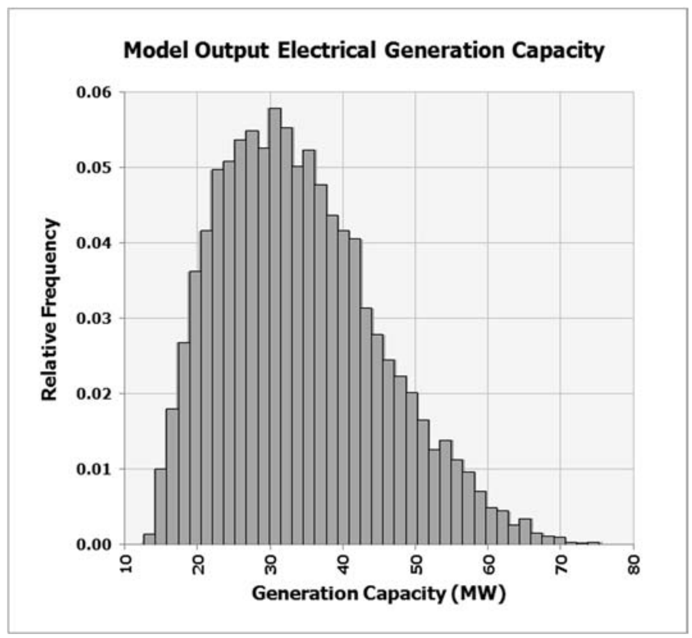

Figure 11. Histogram of the electrical generation capacity model output (W_e) (MW).

Discussion

The recoverable thermal energy from the aquifer at the Clarke Lake Field is significant. For comparison, the mean result of 10.1 x 10^{14} kJ is equivalent to approximately 165 million barrels of oil in energy content (a barrel of oil contains approximately 6.12 x 10^6 kJ that can be released through combustion). If utilized for electricity and heating, this energy represents a sizable renewable resource that could be utilized in the Fort Nelson region.

This estimate of recoverable energy is dependent on three primary inputs: reservoir volume, reservoir temperature and recovery factor. The @Risk modeling software allows comparison of the impact of input changes has on the model output (Figure 12). The bar graph reflects the sensitivity of the model's output (the well head recoverable thermal energy in kilojoules) from a change of one standard deviation in each input. A change in the input of either the recovery factor or reservoir volume by one standard deviation will result in a substantial change in the estimate of well head recoverable energy (78% and

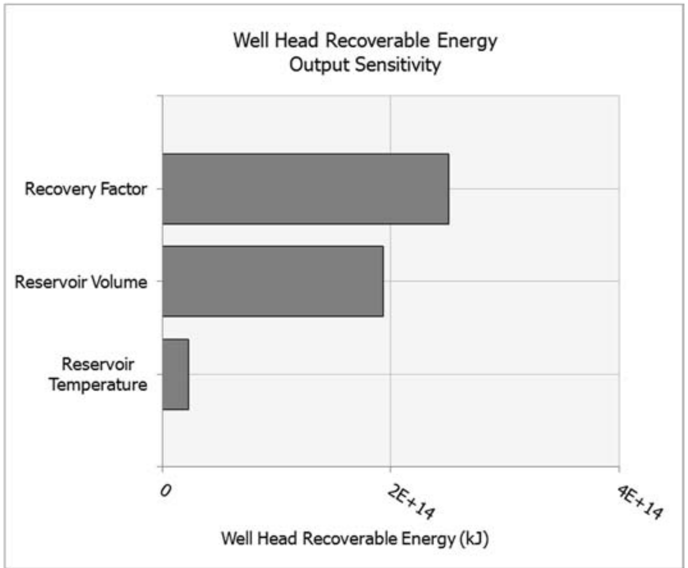

Figure 12. Sensitivity of the model output of well head recoverable energy (q_{WH}) (kJ). For each input factor the bar graph represents the difference in the model output of well head recoverable energy from a change in one standard deviation of that input.

70% of the output standard deviation respectively). However, a change of one standard deviation of the reservoir temperature would have a limited impact on the estimated well head thermal energy (7% of the standard deviation) (Figure 12).

Recovery factor is dependent on the porosity and permeability of the formation. Further refinement of the recovery factor would require field scale hydrogeological modeling and is therefore beyond the scope of this paper. Although the reservoir is well documented, the large range of total volume is justifiable, since this represents the uncertainty in the reservoir properties along the entire reservoir trend. Given the large geographic extent of aquifer, the most likely development scenario would involve several smaller generation facilities clustered around groups of production wells.

A practical approach is to evaluate the generation capacity based on assumptions of single well deliverability, which then can be multiplied by the assumed number of wells supplying the generation facility. A development of this type would likely have up to five directionally drilled production wells from a central location that could provide both the flow and an efficient and convenient location for a geothermal plant (DiPippo, 2013, personal communication).

For this analysis, the recoverable thermal energy (q_{WH}) was estimated from a range of potential mass flow for a single production well. There is a large history of production data where the thermal brine was produced as a by-product of natural gas production. The maximum water production rate in the field associated with natural gas production is approximately 800 m^3/day (approximately 9 kg/sec). This rate, although large in that context, is quite low for a geothermal development. Much larger flows are desired for geothermal developments.

Polsky et al. (2008) cites a flow of 80 kg per second (6770 m^3/day) as an economic minimum for the development of enhanced geothermal systems; a similar mass flow would be advantageous for this project. Down-hole pumping of the reservoir by Petro-Canada had a maximum rate of 1800 m^3/day (approximately 21 kg/sec) from an existing deepened gas well (Petro-Canada, 2009); the well had a productivity of 0.75 (m^3/d)/kPa. A purpose built geothermal well would require a larger diameter casing to allow the placement of a submersible pump near the target reservoir. Assuming a reservoir pressure of 14000 kPa (Petro-Canada, 2009) and using the productivity measured by Petro-Canada, a flow of 8400 m^3/day or (approximately 100kg/sec) could be achieved with eighty percent of the available head (14000 kPa*0.75 (m^3/day)/kPa*.08 = 8400 m^3/day). A more detailed analysis of the reservoir properties and productivity of the reservoir is beyond the scope of this paper.

Figure 13 shows the generation potential for a range of well production and brine temperatures. This demonstrates that purpose-built geothermal wells delivering between 80–100 kg/sec would produce approximately 1.2 to 1.5 MW at 115°C. A cluster of five geothermal wells could support a 6–7.5 MW plant at Clarke Lake. The volumetric analysis indicates that the total field would be able to supply enough thermal energy to support several such geothermal plants. Further work will be required to understand the economic aspects of such a development. In addition, there is a need to further evaluate the geothermal potential of the geologic trend of porous Middle Devonian reefs that hosts the Clarke Lake Field.

Conclusions

The Middle Devonian aquifer at the Clarke Lake Gas Field near Fort Nelson, British Columbia is a significant thermal energy reservoir that could provide a major portion of the energy demand of local communities and oil and gas facilities in northeast British Columbia. High water deliverability and temperatures in excess of 110°C have been documented from the existing gas wells in the field. An estimate of the total recoverable thermal energy from the field of 10.1 x 10^{14} kJ with a standard deviation of 3.2 x 10^{14} kJ was calculated using a stochastic model of the USGS Volume Method.

Using existing binary geothermal plant technology, geothermal plants using the production from several wells could be located in the field. It is estimated that a plant using the delivery from five wells is capable of generating approximately 6–7.5 MW of electricity. Furthermore, the total generation potential of the Clarke Lake field was estimated as 34 MW with a standard deviation of 10.8 MW, indicating that several such plants could be built.

Acknowledgments

This work has been supported by the Office of the Chief Technology Officer at BC Hydro and I would like to especially acknowledge Alex Tu. I appreciate the direction, support and encouragement of the Electricity and Alternative Energy Division in the Ministry of Energy, Mines and Natural Gas: Sue Bonnyman, Andrew Pape-Salmon, Paul Wieringa, and Les McLaren. Input and comments from Dr. Ronald DiPippo and Dr. Colin Williams are appreciated. Supporting formation tops data and mapping were supplied by Jeff Johnson of the Oil and

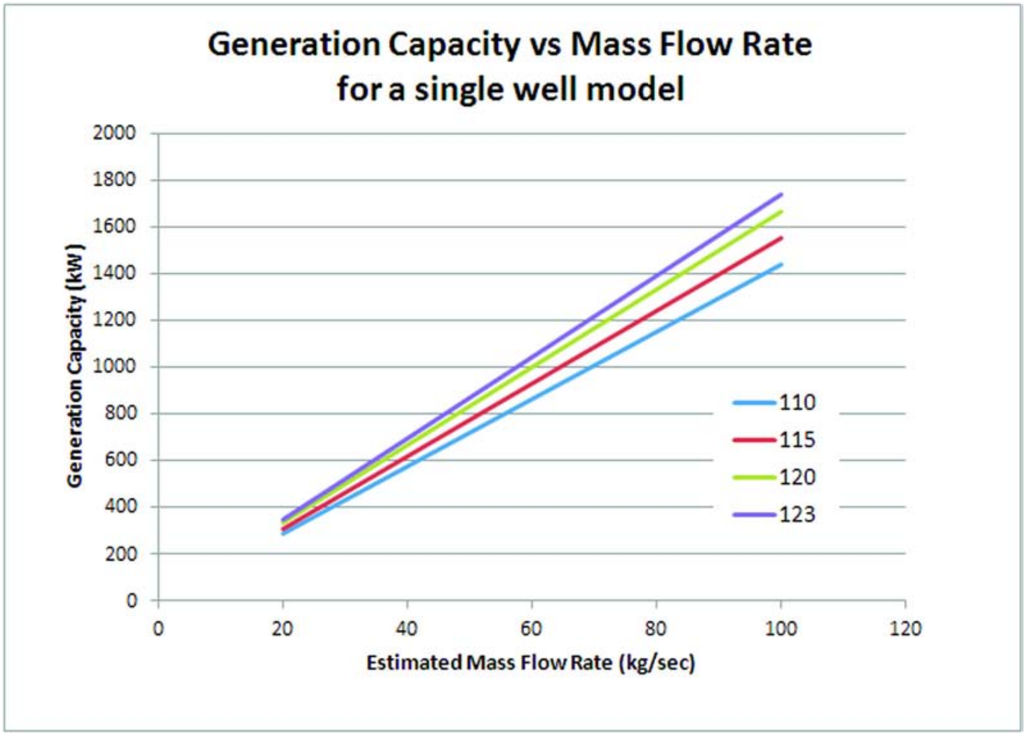

Figure 13. Capacity in kilowatts on a per-well basis as a function of mass flow rate (kg/s) and temperature (°C).

Gas Commission and Dr. Jeff Lonnee. This report has benefited greatly from reviews by Dr. Steve Grasby, Dr. Richard Erdlac, Dr. Ronald DiPippo, Janet Riddell, Aaren Madden and Dr. Elizabeth Johnson. I appreciate the review of this manuscript by Dr. Burns Cheadle and anonymous reviewers from the CSPG.

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Manuscript received: April 11, 2013
Date accepted: August 13, 2013
Associate Editor: Stephen Grasby