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Geothermal Power Potential of the Virginia Hills Oil Field, Part of the Swan Hills Carbonate Complex; Alberta, Canada

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ABSTRACT

Exploitation of hydrocarbon resources throughout the Western Canadian Sedimentary Basin has been accompanied by the production of trillions of cubic meters of aqueous fluids, i.e. brines, which are either recirculated to maintain reservoir pressure, or reinjected in far-flung disposal wells. Basin-wide, these brines carry petawatts of thermal power to the Earth's surface. Socio-economic demand for renewable power, coupled with recent advances in low-enthalpy waste heat recovery, has led to increasing interest from oil field operators in geothermal co-production. This paper explores the potential scale of geothermal co-production from an oil-producing pinnacle reef in the Swan Hills Complex of central Alberta, Canada. In this study, we combine geospatial, hydrogeological, and thermodynamic data to build reservoir volume-based model of the Virginia Hills field. We analyze the effects of variable temperature, porosity, thermal recovery factor and engine efficiency on the geothermal power potential of this reservoir on individual well-head scale and for exploitation of the entire oil field. Ranges of potential input variables were compiled from data available through licensed servers of geoSCOUT and data made available directly from Razor Energy. Uncertainty in the data is accounted for through use of Monte Carlo simulations in executing the volumetric assessments. On a wellhead level, the average production potential is 0.6 MW_{th} and 0.1 MW_e. Scaled-up to reflect the 190 suspended wells in the field yields a total potential of ~115 MW_{th} and 16 MW_e. When a reservoir volume-based assessment method is applied to a 25-year production period, the field's mean power potential is ~172 MW_{th} and 28 MW_e. Results from this case study form an example of the overall potential of geothermal co-production from oil-producing pinnacle reefs in the Swan Hills Complex in the Western Canadian Sedimentary Basin.

1. INTRODUCTION

The Western Canadian Sedimentary Basin is a continental-scale wedge of phanerozoic sediments ranging from the southern part of the Northwest Territories, south-southeast through northeastern British Columbia, Alberta and southern Saskatchewan; and across the United States' border into Montana and North Dakota. The basin is 600 – 1200 km wide and is bounded in the west by the Rocky Mountain Fold and Thrust belt and in the east by the exposed Canadian Shield. It deepens from the northeast to the southwest, where it approaches 6000 m depth adjacent to the North American Cordillera near the towns of Grande Cache and Hinton, Alberta.

The Western Canadian Sedimentary Basin contains roughly 2 trillion barrels of crude bitumen and oil, a trillion cubic meters of natural gas, and 100 billion tons of coal (Alberta Energy Regulator, 2017). Exploitation of these resources has created a comprehensive set of geotechnical data from the basin's subsurface. Public access to this data through licensed servers such as GeoScout and AccuMap has led to a long history of geothermal energy research in the Western Canadian Sedimentary Basin, culminating in a robust understanding of its geothermal regime (e.g Weides & Majowicz, 2014; Banks & Harris, 2018; Majorowicz & Grasby, 2019). As shown in Figure 1, the geothermal gradients throughout the basin range from less than 20 ˚C/km in the southwest along the mountain front and the northeast where the basin cover is thin, to over 50 ˚C/km in British Columbia, the Northwest Territories and northern Alberta. Elevated geothermal gradients, i.e. greater than 30 ˚C/km, are also found near Grande Prairie and Edmonton, two population centers, and near Swan Hills, a hydrocarbon producing region.

While the economic viability of exploiting many of the Western Canadian Sedimentary Basin's low temperature geothermal resources has historically been called into question, changing economic and social climates, combined with advances in waste-heat recovery technology, have led to increasing interest from upstream hydrocarbon operators in geothermal power co-production. This study investigates the feasibility of using the geothermal energy contained in co-produced oil field brines to power upstream operations in the Swan Hills region of central Alberta. The Swan Hills Formation is a regionally extensive carbonate platform upon whose margins trends of atoll reefs have accumulated (Fig. 1). One such trend underlays the Swan Hills geographic region of Alberta, where oil pools found in discrete reef buildups have been extensively produced via water flooding. Razor Energy, a regional operator, has partnered with the University of Alberta, Alberta Innovates and Natural Resources Canada to develop methods of using the thermal energy content of the co-produced waters to provide baseload, renewable power for their upstream operations. Here, we compare results of two methods for assessing the gross geothermal power potential of the Virginia Hills oil field, one of Razor's local assets. In the first method, we use a reservoir volume-based Monte Carlo simulation to estimate the gross power potential of the reef as a single geothermal reservoir. In the second method, we use historical production data to estimate the gross power potential of the field as an aggregate of individual well head potentials.

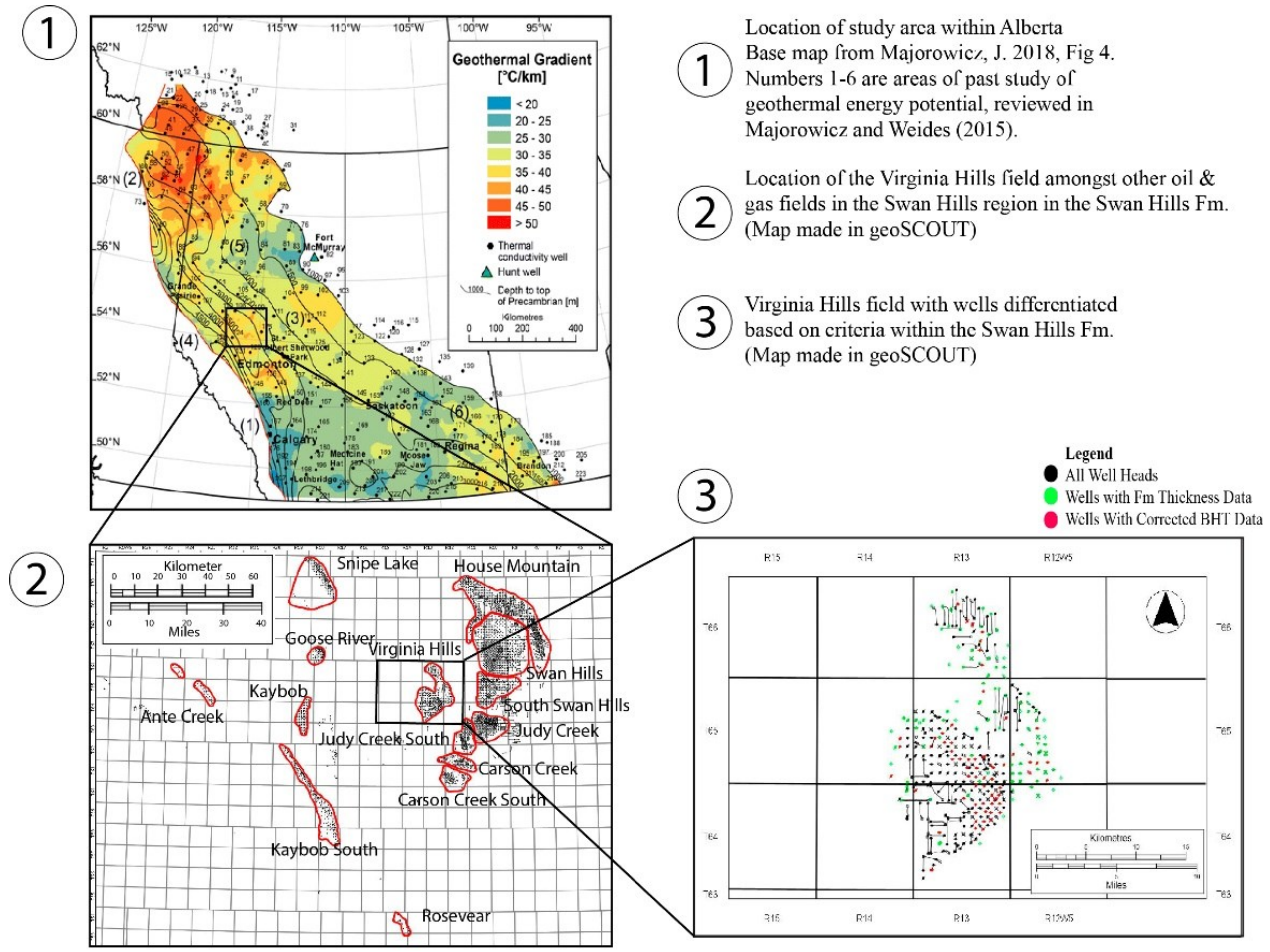

Figure 1 Location of the Virginia Hills oil field within the context of the Western Canadian Sedimentary Basin. (1) Geothermal gradient throughout the Western Canadian Sedimentary Basin (from Majorowicz & Weides, 2015). (2) Location of the Virginia Hills field with the Swan Hills Carbonate Platform reef system. (3) Distribution of wells within the Virginia Hill field used in this study.

2. THE VIRGINIA HILLS OIL FIELD

2.1. Data and Methods

Some 320 wells were drilled into the Virginia Hills oil field, of which 30 have cored sections and 150 have depth data on the top and base of the Swan Hill Formation (**Error! Reference source not found.**). Fluid properties and historical production data from 190 suspended oil wells in the field were taken from geoSCOUT. These production data included Bottom Hole Temperature and average daily oil and water production rates from the last year of operation. Bottom hole temperature corrections were made using a 'time since circulation' method (Corrigan, 2003). Only data from suspended oil wells were collected. Abandoned wells were neglected due to the difficulty of bringing these wells back into operation.

2.2 Reservoir volume calculation

A uniform distribution of the estimated bulk rock volume was assumed. The maximum bulk rock volume in this distribution was the volume of the entire Swan Hill Formation. This volume was derived from the top and base surfaces of the Swan Hills Formation in the Virginia Hills Field, which were generated using formation depth data points from the geoSCOUT database (**Error! Reference source not found.**). The minimum bulk rock volume was estimated by using core-plug porosity logs to establish a shallower base reservoir surface. These logs indicate that mainly the top layer of the carbonate platform is porous. The base of this porous rim was interpreted on the logs by assuming a porosity cutoff value of 5% (Satter & Iqbal, 2016). By interpolating the depth of these interpretations between wells, the base of the reservoir for the minimum bulk rock estimate was generated. The minimum bulk rock volume was calculated as the volume between the top of the Swan Hill Formation and this surface, as shown in Figure 2. For simplicity, the angle of the reef margin slope volume was assumed to be vertical. We assumed that the maximum extent of the reservoir was 800 m around the outermost wells of the field. This is the distance between wells in the nine-spot grid. We used this value because we assumed that if the reservoir would extend further, an additional rim of wells would have been drilled.

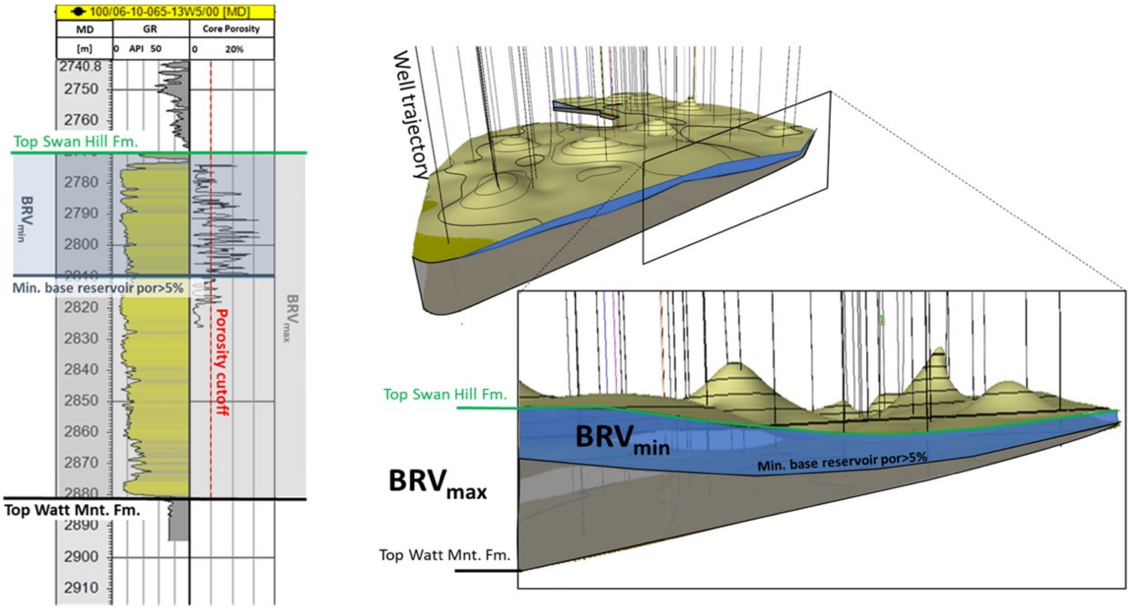

Figure 2: Example of derivation of the minimal and maximal reservoir base surface on a Gamma Ray (GR) log and core-plug porosity log. Interpolation of these surfaces formed the bases for calculating the maximum and minimum value of the bulk rock volume distribution.

2.3 Full-field Gross Power Potential Monte Carlo Simulation

The gross power thermal and electrical power potential of the Virginia Hills oil field taken as a single geothermal reservoir was estimated according to the method described by Banks and Harris (2018), using a Monte Carlo simulation with 10,000 iterations. A table (Table 1) of variables associated with this method is found below the description. This method first calculates the bulk energy of content of the reservoir with respect to the ambient environmental conditions at the surface:

$$(Q_r) = (V_{rock}Cp_{rock)} + (V_{brine}Cp_{brine})]*(T_r - T_0) \quad (1)$$

Where Q_r is the thermal energy content of the reservoir in kilojoules (kJ), $V_{rock,brine}$ is the volume of the subscripted material in cubic meters (m^3), and $Cp_{rock,brine}$ is the volumetric heat capacity of the subscripted material in kilojoules per cubic meter Kelvin (kJ/m^3K). T_r and T_0 are the reservoir and ambient environmental temperatures, respectively, in K. Reservoir temperatures are custom inputs from the well data. Ambient conditions are a Gaussian distribution of monthly air temperatures in Swan Hills, AB, taken from Climate-Data.org (2019).

The rock and brine volumes are functions of the reservoir's porosity (ϕ) and bulk volume (V_{bulk})

$$V_{rock} = (1-\phi)V_{bulk} \quad (2)$$

$$V_{brine} = \phi V_{bulk} \quad (3)$$

A custom porosity distribution based on the core data from the Swan Hills Formation at Virginia Hills is used as the input.

The amount of the reservoir's heat (Q_r; kJ) that can be brought to the surface (Q_{surf}; kJ) is estimated by applying a recovery factor

$$Q_{surf} = \gamma Q_r \quad (4)$$

An even distribution between 5% and 15% is assigned as the simulation input. This is a conservative estimate based on the work of Williams (2007). The amount of fluid in kilograms required to transport this heat to the surface (M_{surf}) is defined by the quotient of the Q_{surf} and the difference in the transport fluid's enthalpy (ΔH) between the reservoir and ambient temperatures.

$$M_{surf} = Q_{surf}/\Delta H \quad (5)$$

Any of several online steam tables will show the enthalpy of liquid water to be a linear function of temperature (e.g. Wischnewski, 2019)

$$H = (4.2477*T) - 1{,}163.5735 \quad (6)$$

The exergy (W_A; kJ) of the reservoir, or amount of energy available to perform useful work is a product of surface flow rate and the thermodynamic losses associated with the fluid's temperature drop between the reservoir and ambient temperatures

$$(W_A) = M_{wh}*(\Delta H - T_0\Delta S) \quad (7)$$

Here, similar to the enthalpy, the change in entropy is a regressive function available from standard steam tables

$$\Delta S = 3.521E\text{-}08\ T_{(r,0)}^3 - 2.461E\text{-}05T_{(r,0)}^2 + 1.516E\text{-}02T_{(r,0)} + 2.504E\text{-}03 \quad (8)$$

The system's gross thermal power potential in megawatts (MW_{th}) is then obtained by dividing the exergy (W_A) by 1000 times the duration of production (t) in seconds

$$MW_{th} = W_A /1000^* t \quad (9)$$

The gross electrical power is calculated by applying a heat-to-electricity conversion factor (η) to the gross thermal power,

$$MW_e = \eta MW_{th} \quad (10)$$

where η is function of T_r, as described by Augustine et al (2009)

$$\eta = [(0.3083^*T_r)-98.794]/100 \quad (11)$$

A number of other meaningful output variables can be derived from this heat-in-place analysis, including the bulk flow rate (M_{bulk}; kg/s) required for maximum resource exploitation

$$M_{bulk} = 1000^*MW_{th}/(Cp_{brine}^*\Delta T) \quad (12)$$

the specific flow rate (M_{sp}) require per unit thermal or electrical power production ($MW_{th,e}$)

$$M_{sp} = M_{bulk}/MW_{th,e} \quad (13)$$

and the specific power potential (MW_{sp}) per unit reservoir volume (km^3)

$$MW_{sp} = (MW_{th,e}/V_{bulk})^* 10^{\wedge 9} \quad (14)$$

Table 1 Table of variable, symbols, units and input types for Virginia Hills geothermal power Monte Carlo simulations

Variable	*Symbol*	*Units*	*Type*	*Values*
Reservoir bulk energy	Q_r	kJ	Output	= $(V_{rock}Cp_{rock)} + (V_{brine}Cp_{brine})]^*(T_r - T_0)$
Rock heat capacity	Cp_{rock}	kJ/m^3K	Fixed	2300
Brine heat capacity	Cp_{brine}	kJ/m^3K	Fixed	4200
Reservoir bulk volume	V_{bulk}	m^3	Even	Full reservoir volume; 5% cutoff
porosity	ϕ	decimal	Custom	From well data
Reservoir rock volume	V_{rock}	m^3	Output	$= (1-\phi)V_{bulk}$
Reservoir brine volume	V_{brine}	m^3	Output	$= \phi V_{bulk}$
Reservoir temperature	T_r	K	Custom	From well data
Reference temperature	T_0	K	Gaussian	From regional climate data
Recovery factor	γ	decimal	Even	Min 0.05 mean .1, max 0.15
Gross surface energy	Q_{surf}	kJ	Output	$= \gamma Q_r$
Gross mass of fluid	M_{surf}	kg	Output	$Q_{surf}/\Delta H$
Enthalpy	H	kJ/kg	Outpit	$= (4.2477^*T) - 1{,}163.5735$
Entropy	S	kJ/kgK	Output	$= \Delta S = 3.521E\text{-}08\ T^3 - 2.461E\text{-}05T^2 + 1.516E\text{-}02T+2.504E\text{-}03$ (eq 8)
Exergy	W_A	kJ	Output	$= M_{surf}^*(\Delta H - T_0\Delta S)$
Time	t	seconds	fixed	7.88E8 seconds (25 years)
Gross Thermal Power	MW_{th}	MW	Output	$= (W_A/t)/1000$
Gross Electrical Power	MW_e	MW	Output	$= \eta MW_{th}$
Electricity conversion factor	η	Decimal	Output	$= [(0.3083^*T_r)-98.794]/100$
Gross bulk flow rate	M_{bulk}	kg/s	Output	$= 1000^*MW_{th}/(Cp_{brine}^*\Delta T)$
Specific flow rate	$M_{sp,th,e}$	$(kg/s)/MW_{th,e}$	Output	$= M_{bulk}/MW_{th,e}$
Specific power potential	$MW_{sp,th,e}$	$MW_{th,e}/km^3$	Output	$= MW_{th,e}/V_{bulk}{}^*10^{\wedge 9}$
Well head potential	kWth	kWth	Output	$= M\_dot_{brine}{}^*Cp_{brine}{}^*\ \Delta T$

2.4 Calculation of heat and energy production from suspended wells

The second method this study employs to estimate the gross geothermal power capacity at the Virginia Hills oil field is based on temperature and historical flow rate data for individual wells. Here, we employ the standard thermal power equation

$$kW_{th} = (\dot{m}_{brine})(Cp_{brine})(\Delta T) \qquad (15)$$

where $\dot{m}_{brine}$ is the produce water flow rate in kg/s, Cp_{brine} is the brine's heat capacity in kJ/kgK and ΔT is the difference between the well head and ambient air temperatures. Similar to the electrical power equation above (eq. 10), the electrical power potential of an individual is calculated by multiplying its thermal power potential by a heat-to-recover factor (η; eq. 11).

We calculated the individual well head power potential with both a deterministic and a stochastic method. In the deterministic method, we directly calculated the power potential for each well that had temperature and historical water production data. We then used the distribution of results from the deterministic model as inputs in a Monte Carlo simulation. Both $\dot{m}_{brine}$ and the wellhead temperature are custom input ranges. The ambient temperature is the same Gaussian distribution shown in Table 1. Per-wellhead power calculations derived from the Monte Carlo simulation are then extrapolated to the total number of wells in the Swan Hills Carbonate Complex, to get a first-order sense of the regional scope of this geothermal co-production opportunity.

3. RESULTS

3.1. Full Virginia Hills Field Monte Carlo Power Estimate

3.1.1. Input Variable Distributions

The top of the Swan Hill Formation reservoir is characterized by mounds of carbonate reef ranging from 40 to 60 m in height (Figure 2). The base of the Swan Hill Fm. is formed by the southwest dipping shelf of the Watt Mountain Formation. on which carbonate complex developed. The thickness of the Swan Hill Formation varies from some 20 m in the eastern part of the field to 120 m in the southwest and extends ~180 m below the mounds. The volume of the entire Swan Hills Formation is 2.3e10 m^3, which is the high end of the uniform distribution of the bulk reservoir volume in the Monte Carlo simulation estimate. The low end of the bulk reservoir distribution, which was derived from the 5% porosity cutoff, is 9.6e9 m^3.

With these input parameters, the bulk reservoir volume calculated by the Monte Carlo simulation is 16.3 ± 3.88 km^3. The mean and median of the porosity calculated porosity distribution, based on a custom input distribution, are 0.08 ± 0.02 and 0.08. The mode of the porosity distribution is 0.06. Thus, the simulation calculates the volume of reservoir rock and brine in the Virginia Hills field to be 14.96 ± 3.59 km^3 and 1.35 ± 0.46 km^3, respectively.

The corrected bottom hole temperatures for the wells in the Virginia Hills field range from 63 – 114 °C with an average 95 ± 10 °C. The custom distribution of reservoir temperatures entered into the Monte Carlo simulation results in a calculated distribution of 100.35 ± 47.3 ˚C (mean ± 1 standard deviation), with a median of 99.75 ˚C and a mode of 98.45 ˚C. Monte Carlo simulation inputs for the ambient temperature were given as a Gaussian distribution of the mean and standard deviation of the average air temperature in Swan Hills, AB, i.e. -0.5 ± 10.8 ˚C. The resulting Monte Carlo distribution of ambient temperatures is -0.65 ± 10.7 ˚C. Both the median and mode of the distribution are also -0.65. Monte Carlo distributions for both the reservoir and ambient temperatures are shown in Figure 3.

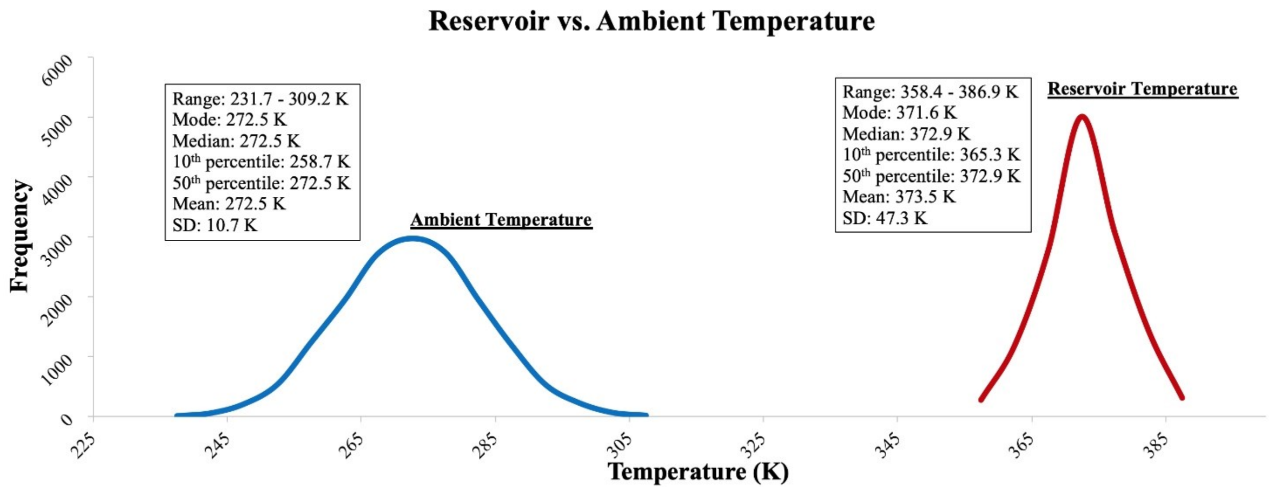

Figure 3 Ambient (blue) and reservoir (red) temperature input distributions

3.1.2. Reservoir energy content

The energy content of the Virginia Hills reef was calculated as a bulk property the reservoir, a property of the reservoir considered in light of a recovery factor, and in terms of the field's exergy. Results from all three of these calculations are shown in Figure 4. The total energy content of the reservoir, Q_r is calculated to be 4.03 ± 1.08 Petajoules (PJ). An even input distribution of 0.05 – 0.15 recovery factors yields simulated recovery factor of 0.1 ± 0.03. Applying this recovery factor results in surface energy content (Q_{surf}) of 0.4 ± 0.16 PJ. Delivering this heat to the surface requires moving 9.44E11 ± 3.61E11 kilograms of fluid to the surface. Factoring in the thermodynamic losses associated with producing this fluid yields 0.14 ± 0.06 PJ of exergy, or useable work, at the surface.

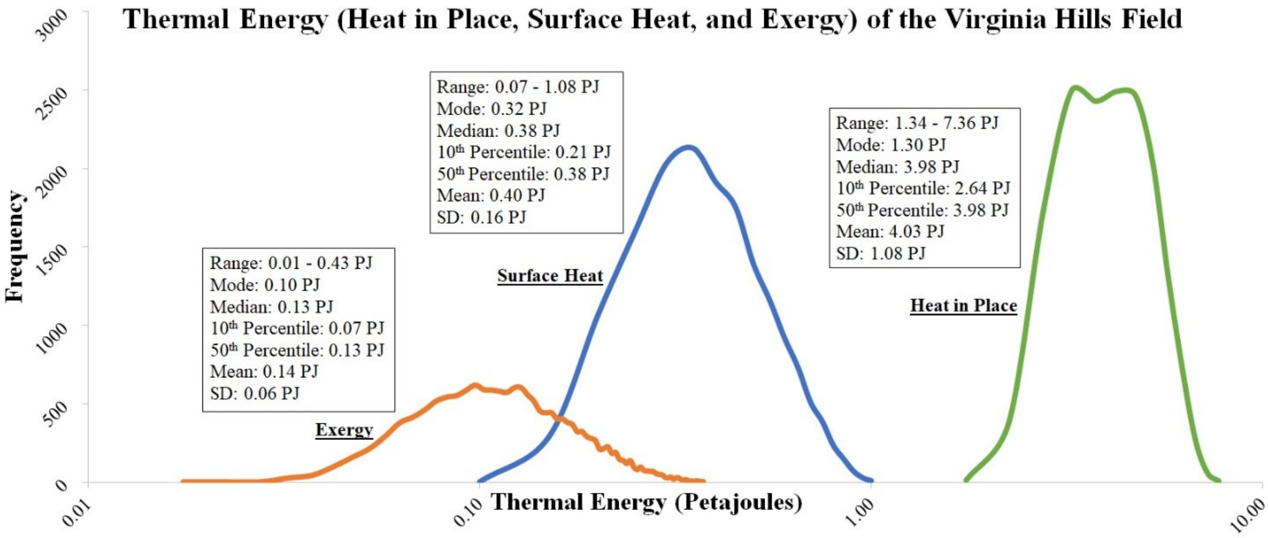

Figure 4 Thermal energy content of the Virginia Hills oil field

3.1.3 Power Potential Calculation

Results for gross thermal and electrical geothermal power potential from the Virginia Hills oil field are shown in Figure 5. Amortizing the field's thermal exergy over a 25-year production period results in a gross thermal power potential of 172.4 ± 75.7 MWth, with a median and mode of 159.3 MWth and 125.0 MWth, respectively. Based on the range of input temperatures, the average heat-to-electricity conversion factor (γ) is 0.16 ± 0.02. This factor yields a gross electrical power potential of 29.9 ± 13 MWe, with a median of 25.5 MWe and a mode of 22.5 MWe.

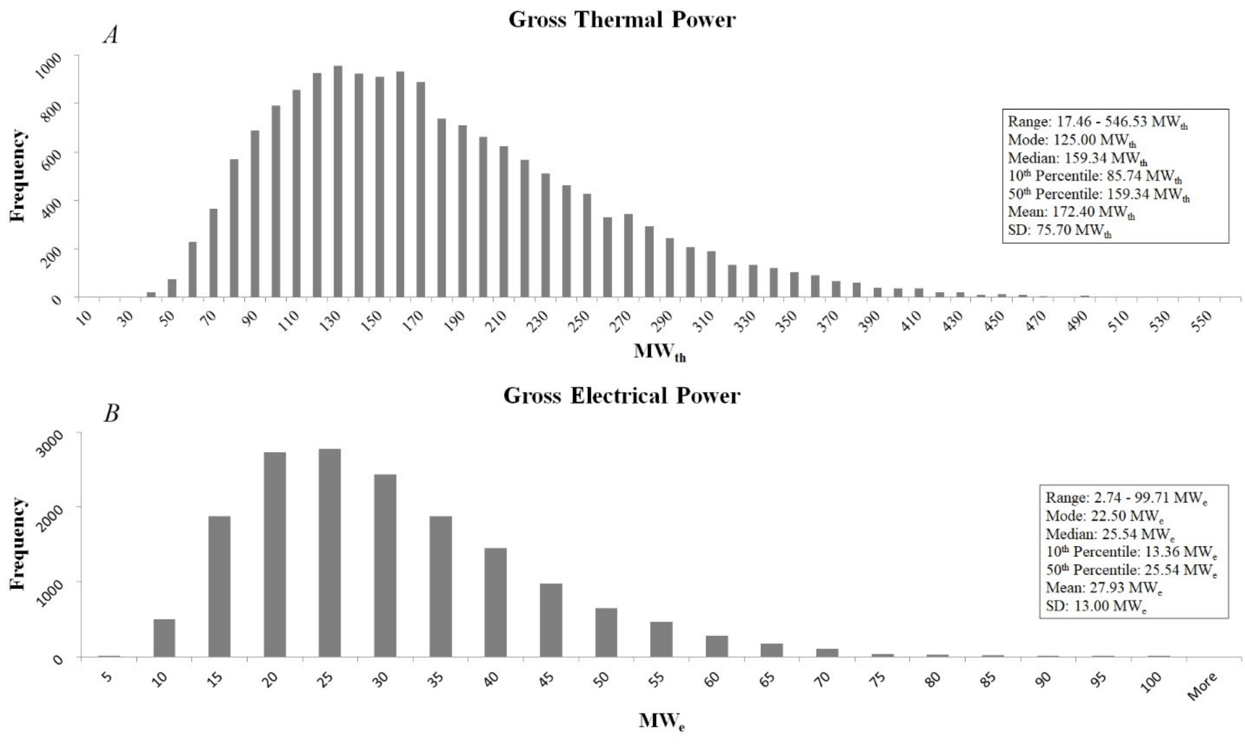

Figure 5 Gross thermal (left) and electrical (right) power production predictions for the Virginia Hills oil field

3.1.4 Specific Power Metrics

Results from the gross power calculations are used to estimate the power potential on a per-cubic kilometer of reservoir basis, as well as to compute the flow rate (in kg/s) required to produce a megawatt of power. These results are shown in Figure 6. According to our simulation a cubic kilometer of reservoir has an average geothermal power potential of 10.5 ± 3.8 MWth/km^3. Applying the same heat-to-conversion factor discussed above (eq. 11) results in a specific electrical power potential of 1.71 ± 0.67 MWe/km^3. The flow rates required to produce 1 megawatt of thermal and electrical power are 2.41 ± .031 kg/s per MWth and 15.22 ± 3.12 kg.s MWe, respectively.

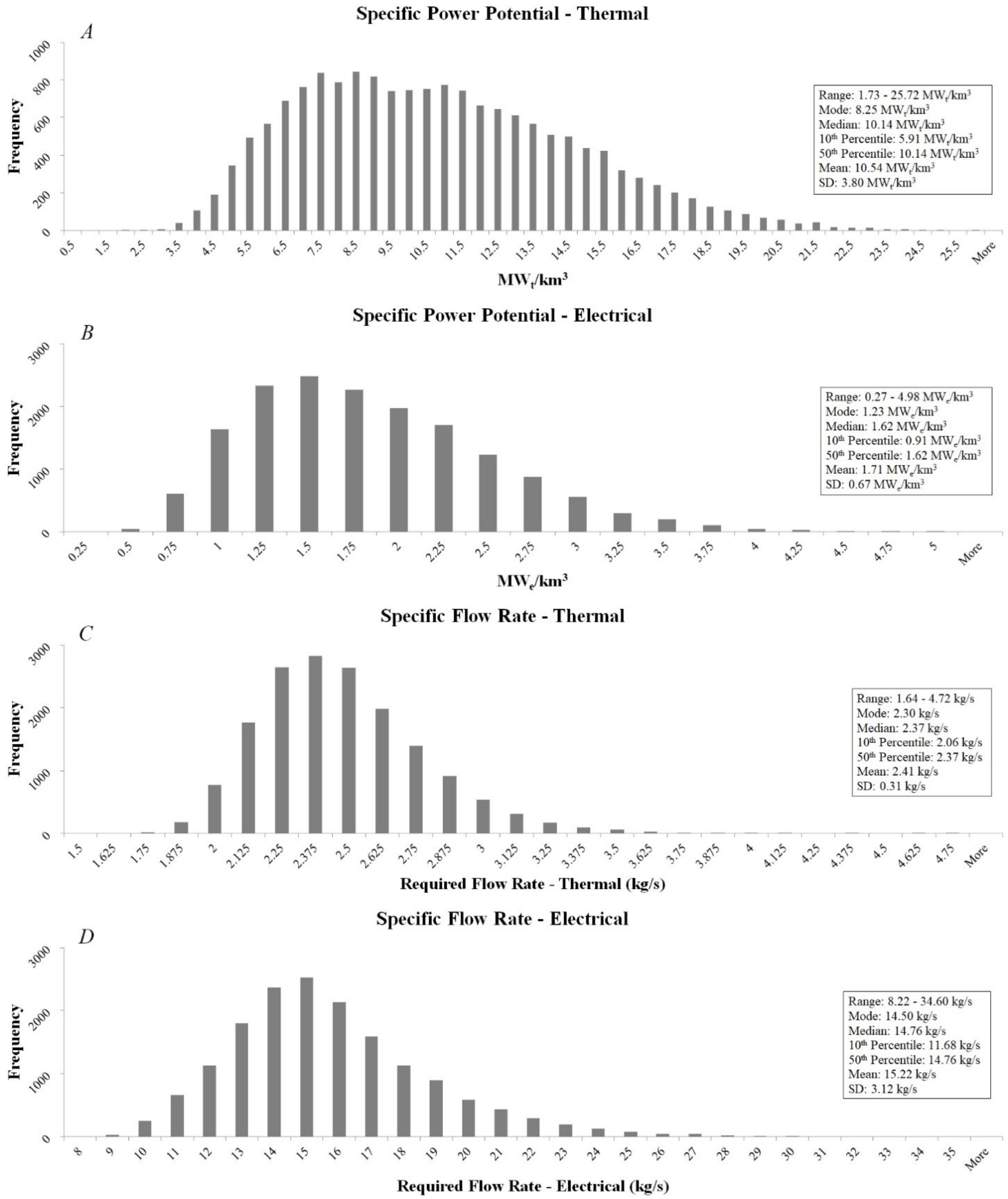

Figure 6 Specific power (MW/km^3; above) and specific flow rate (kg/s per MW; below) for thermal (left) and electrical (right) power

3.2. Wellhead Power Potential

3.2.1. Deterministic wellhead calculations

A scatterplot of the well temperatures and flow rates used in the deterministic calculations of wellhead power potential are shown in Figure 7. The temperature inputs are the same the custom reservoir temperature distribution used as the Monte Carlo simulation input, i.e. 95 ± 10 ˚C. The average flow rate is 1.56 ± 2.68 kg/s. Wells with the highest water cut also have the highest flow rates, as shown in Figure 7. Eight of the wells have flow rates of at least 10 kg/s, and twenty-wells have flow rates greater than 5 kg/s.

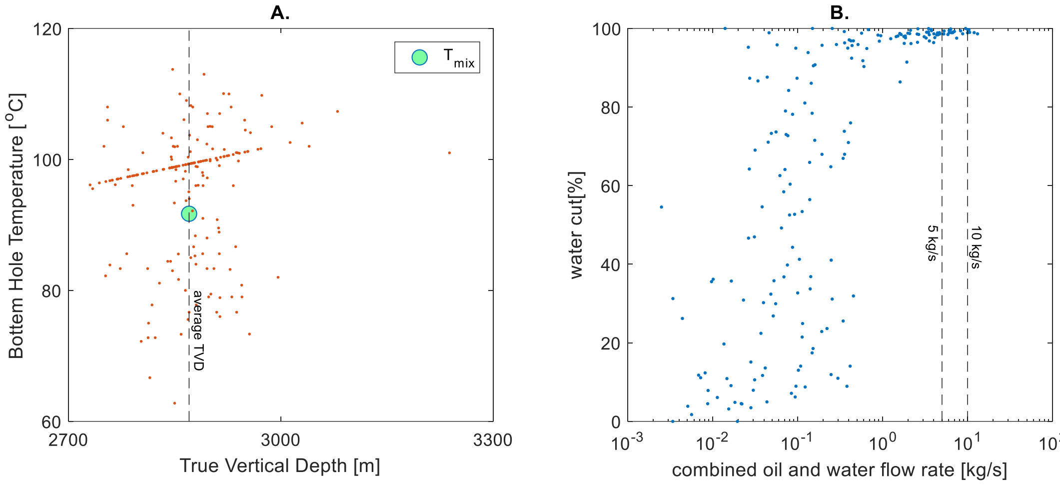

Figure 7: (A) Bottom Hole Temperature and (B) frequency distribution of oil and gas flow rates all 190 suspended oil wells in the Virginia Hills Field.

The average thermal and electrical power potential per well is 0.6 ± 1.0 MW_{th} and 0.085 ± 0.15 MW_e respectively. The total power available from all wells is ~115 MW_{th} and 16 MW_e. The large standard deviation is due to the bimodal distribution of flow rates, with several values being greater than 5 kg/s and many values being fractions of kg/s. If only the top 20 producing wells are chosen, the average well head production estimates are 3.05 ±0.84 MW_{th} and 0.436 ± 0.162 MW_e. The total power available from the top 20 performing wells is ~64 MW_{th} and ~9.2 MW_e. This is a somewhat arbitrary cutoff. Under the given conditions, 53 wells may produce more than 100 kWe. The average power potential of these 53 wells is 1.97 ± 1.1 MW_{th} and 0.28 ± 0.17 MW_e. The total power potential for these 53 wells is ~104 MW_t and 14.9 MWe.

3.2.2. Wellhead Monte Carlo Simulation

According to the Monte Carlo simulation, the average thermal and electrical power capable of being produced at individual well flow rates is 0.63 ± 1.09 MW_{th} and 0.102 ± 0.18 MW_e, respectively. The wells range in thermal and electrical power production from 3.88e-5 to 7.37 MW_{th} and 5.57e-6 to 1.32 MW_e respectively. The thermal and electrical power output of wells is skewed towards the lower range of values, with median values being below the mean in both cases, indicating high output wells increasing the average power output. Summary of statistics can be found for individual wellhead thermal and electrical power analyses in Figure 8. If the average per-wellhead power potential from the Monte Carlo simulation is applied to the whole Virginia Hills field (n_{wells} =316), the total thermal and electrical power potential is 199.08 MW_{th} and 32.36 MW_e, respectively

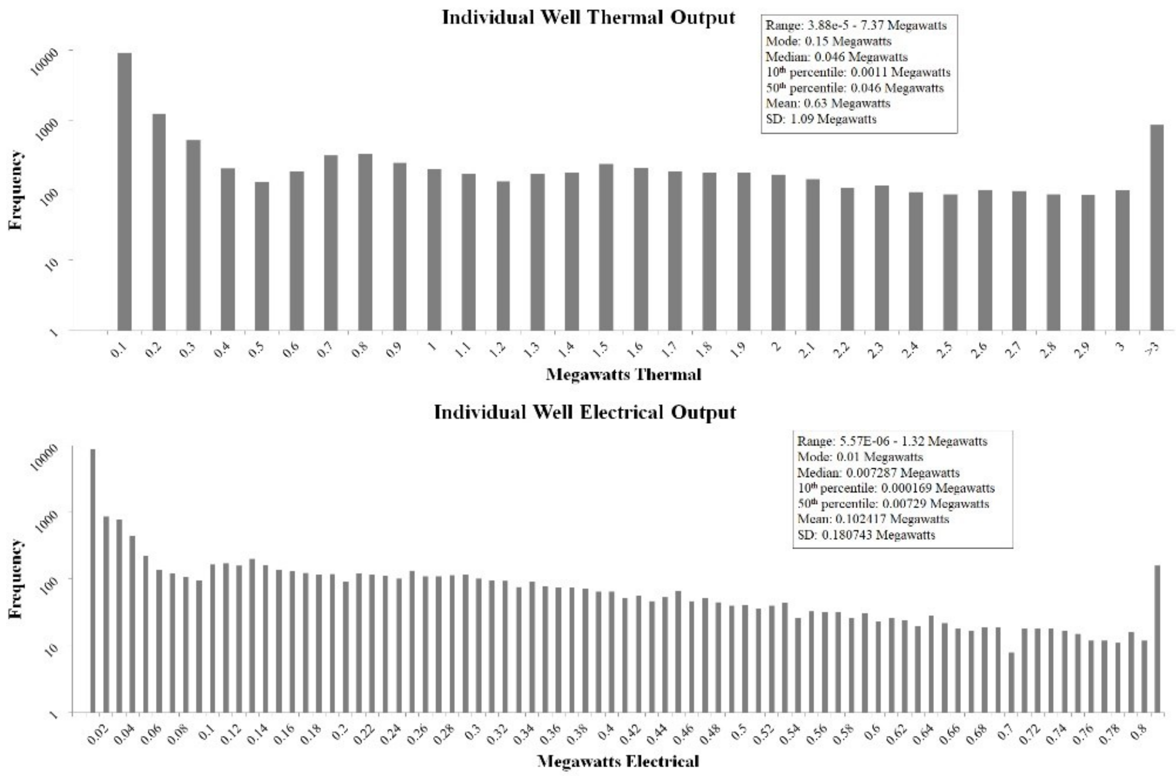

Figure 8 Monte Carlo results for individual well gross thermal (top) and electrical (bottom) power potential

4. DISCUSSION

Three methods were used to estimate the gross geothermal co-generation potential of the Virginia Hills field. The deterministic wellhead power potential estimates are the lowest of the three cases because they consider only suspended oil wells with historical fluid production data. The stochastic wellhead power potential estimates are the highest of three because they consider the possibility of producing from *every* well in the field, at the mean power potential calculated by the simulation. The bulk field analysis falls between the two wellhead analyses. This suggests that, for maximizing thermal energy recovery, drilling geothermal-specific production wells may be preferable to generating from emulsion heat at existing wellheads.

The wellhead power estimates highlight that the co-produced power's first order dependence is on the flow rate. Nonetheless. quantifying the minimum flow rate for producing electricity depends on many parameters, including the bottom hole temperature of each well, the surface facility design costs, ambient environmental conditions, and reinjection temperatures. This last parameter will not only influence the potential heat production (equation 1, 11 and 12) but also the viscosity of the oil in the reservoir, thereby affecting hydrocarbon recovery (e.g. Ziabakhsh-Ganji et al., 2018; Khoshnevis et al., 2019). Considering all variables in the design of an actual operational strategy for co-production in the Virginal Hills region is a multiparameter challenge that requires utilizing field development optimization software (e.g. Hørsholt, Nick and Jørgensen, 2018; Kahrobaei et al., 2019).

The potential heat recovery and power production reported here is larger than previous other geothermal co-production case-studies due to the larger number of suspended oil wells in the Virginial Hills field (e.g. Bennett, Li and Horne, 2012; Xin *et al.*, 2012; Liu, Falcone and Alimonti, 2018; Toth *et al.*, 2018). The specific power and flow rate estimates are higher than those reported in other parts of the Western Canadian Sedimentary Basin (e.g. Banks and Harris, 2018). The differences can be attributed to several factors. First, whereas these previous works used fixed recovery factors, this study employed a range. Second, due to the pervasive well control in the Virginia Hills field, temperature inputs in this study were more constrained, leading to less variability. Third, rather than using a fixed ambient temperature, this study used seasonal variability taken from local temperature data.

Another factor leading to the seemingly elevated power production potential of this field compared to other similar fields is that we used the ambient air conditions as our T_0 input. Some researchers (e.g. Garg and Combs, 2015) have suggested that the outlet temperature of the turbine is the correct formulation of T_0. Turbines, however, are often designed custom designed to the specific environment. Without a detailed engineering study, it is impossible to know this temperature. Additionally, the Virginia Hills field owner (Razor Energy) is interested in discharging as much heat as possible at the wellhead. Therefore, an understanding of the total thermal power output, i.e. with reference to the ambient condition, is also relevant to this study. Thus, we have defined T_0 in terms of the ambient air temperature, as described by other researchers (e.g. Walsh, 2013)

The purpose of this study is to provide an initial estimate of the Virginia Hills field's gross geothermal power potential. A detailed investigation of the geotechnical and economic requirements for commercial co-production at the field is beyond the scope of this work. While results from this study show that there is a commercially significant quantity of geothermal energy in the Swan Hills region, it is unclear whether or not producing it is techno-economically feasible. Two specific factors that may affect the commercial viability of geothermal co-production in active hydrocarbon fields are the parasitic loads associated with production and cooling and the poor efficiency of converting low-enthalpy heat to electricity. To the first point, if the hydrocarbon field is active, the pumping load requirements are bought off the grid; any net power production is money saved on electricity bills. To the second point, advances in modular Organic Rankine Cycle technology, coupled with the low ambient temperature across the Western Canadian Sedimentary Basin, make sites like Virginia Hills attractive proving grounds for cutting edge geothermal co-production systems.

5. CONCLUSION

We investigated the gross geothermal power potential of a hot sedimentary aquifer in the Swan Hills region of Alberta, Canada. The Virginia Hills oil field is a part of trend of atolls built upon the Swan Hills Carbonate Platform in the central-west section of the Western Canadian Sedimentary Basin. Historically, the field has produced oil under water flood conditions, until operations were suspended due to high water cuts, combined with excess (i.e. > 100 ˚C) heat at the wellhead. Recent advances in low-temperature geothermal power production, accompanied by changing socio-economic conditions, has led to renewed interest in restarting the field under its own geothermal power.

We used both a reservoir-volume and a surface heat flow method to assess the Virginia Hills field's gross power production potential. The reservoir-volume method resulted in mean potentials of ~172 MW_{th} and 28 MW_e for a 25-year production period. A deterministic surface heat flow method, based on bottom hole temperature and historical brine production data for 190 wells, yielded mean potential power estimates of ~115 MW_{th} and 16 MWe. A Monte Carlo approach for individual wellhead power, based on a range of inputs derived from the deterministic model, estimated the total potential for the field to be ~199 MW_{th} and ~ 32 $MW_{e..}$

This study is a first step in determining the overall geothermal power potential of the Swan Hills region.

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