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Virtual Event September 21-23 2020
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Geothermal Resource Characterization of the Middle Devonian Carbonate Reef Reservoir at Clarke Lake Field, Fort Nelson, B.C., Canada

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Summary

The Clarke Lake depleted gas field in northeastern British Columbia displays anomalously high reservoir temperature 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 net power production of the first project buildout will be a function of the total mass flow rate and temperature of the geothermal brine along with the binary geothermal power plant conversion efficiency minus any parasitic loads. A 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 is being designed to prove the resource and support further modeling. Drilling and testing of the wells are proposed for the 3rd and 4th quarter of 2020.

Workflow

The first step of the study was to develop a conceptual model of the system from over 60 years of gas development and production data from the Slave Point Formation. Well models and a numerical reservoir simulation were developed from the conceptual model and calibrated with decades of past pressure, temperature and gas production data to estimate flow potential and thermal decline. Reservoir characterization involves description of cores taken from the Slave Point Formation using Dunham's (1962) carbonate classification to identify depositional and diagenetic facies, correlating these facies to well log signatures and mapping facies distribution throughout the field using well logs. Comparing petrophysical measurements with facies, reservoir continuity was interpreted to produce a static geomodel of the reservoir. Seismic data has been used to further constrain the geometry of the reservoir.

Results

Nine depositional facies and two diagenetic facies were described. Deposition of these facies occurred within lagoonal, reef-flat, reef margin, foreslope and open platform settings associated with a rimmed carbonate platform. Observed bioclasts are predominantly stromatoporoids, but also include crinoids, corals, brachiopods, gastropods and ostracods. Packstones and grainstones of Facies 1A and 1B represent reef-flat and lagoonal deposits, which are dominantly composed of nodular stromatoporoid, *Amphipora*, *Stachyodes* and *Thamnopora* bioclasts. Packstones, grainstones and boundstones of Facies 2A and 2B represent high energy reef margin deposits, which are dominantly composed of massive, hemispherical stromatoporoid and *Stachyodes* bioclasts. Dolomitized facies show enhanced porosity and permeability where stromatoporoid bioclasts have been dissolved, leaving mouldic and vuggy porosity (Figure 1). Average porosity and permeability in reef-flat facies are 7.3 % and 68 md. Diagenetic facies show high permeability due to higher amounts of fractures but comparatively reduced porosity from increased precipitation of saddle dolomite, fluorite, and sulphide minerals that occlude mouldic and vuggy porosity (Figure 2). Average porosity and permeability for these facies are 5.0 % and 203 md. High quality reservoir zones exist at the reef margin due to hydrothermal alteration that preferentially occurred in more porous and permeable sediments that are stratigraphically trapped between shales of the Muskwa Formation, Horn River Formation and unaltered, tight limestone within the reef interior. Faults may have provided primary conduits for hydrothermal fluids to move from deeper aquifers upward to the Slave Point reef margin. High quality reservoir zones also extend into the back-reef within porous and permeable carrier beds. Internal flooding surfaces within the reef interior provided baffles to hydrothermal fluid flow, which affect the continuity of the dolomite reservoir.

Well simulations based on history matches of production and injection wells indicate a high productivity index of 0.09 kg/s/kPa. Results from the simulations, historical production, and high permeability thickness of 50 Dm plus, suggest the reservoir can sustain high mass flow rates of 100 kg/sec or more with full injection of produced fluids. An in-depth study of temperature distributions indicates a conductive temperature profile with the primary reef reservoir temperatures ranging from 115 – 140 C. Production temperatures are expected to range from 120 – 130 C with a gross power output of 2 – 3 MWe per well. Potential deeper reservoir rock below the main reef reservoir in the Keg River Platform, the Upper and Lower Chinchaga Formations, and Granite Wash will be explored and tested for permeability and higher temperatures.

Additive Information

Petro-Canada Oil & Gas investigated the viability of liberating trapped gas within Clarke Lake field. To accomplish this, they attempted to depressurize the reservoir by producing formation water at high rates (between 2100 and 2800 m^3/day) between January 1st, 2007 and December 29th, 2008 water (Petro-Canada Oil & Gas, 2009). An unintended result of this experiment was the observation of a strong water drive. Two wells were designated as water producers and two wells as water disposal wells. Six remaining wells were designated as gas lift wells. Water-gas ratio plots showed no gas had been liberated as a result of dewatering. Water rates at one water producer well peaked at 1800 m^3/day while the gas-to-water ratio remained stable at 3 m^3 gas /

m^3. In order to access the trapped gas, they speculated that they would need at least a 1 MPa drop in reservoir pressure. At the end of the experiment they found that reservoir pressure dropped by 100 KPa. This unexpectedly low pressure drop was a result of a high permeability-porosity, hydraulic connection of the thick reef units and a strong water drive.

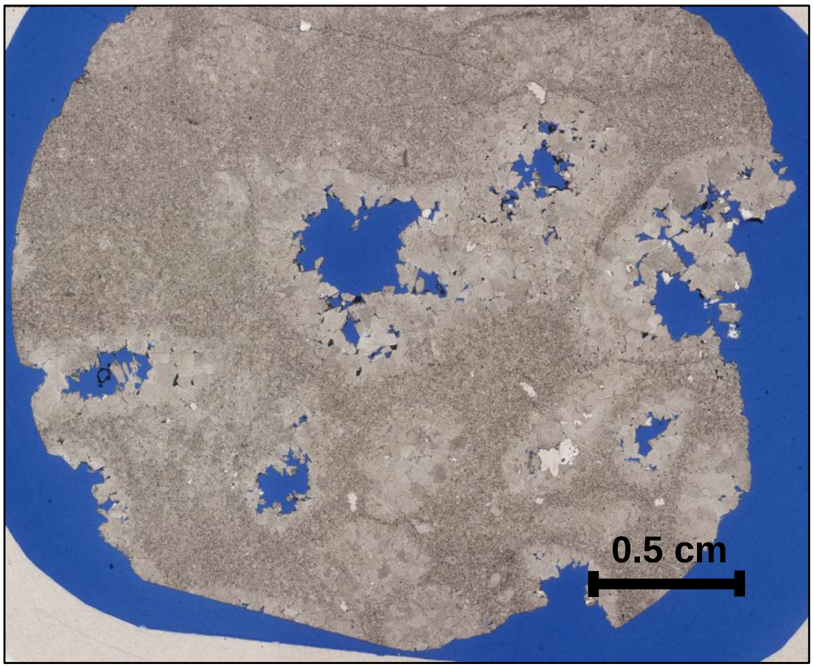

Figure 1

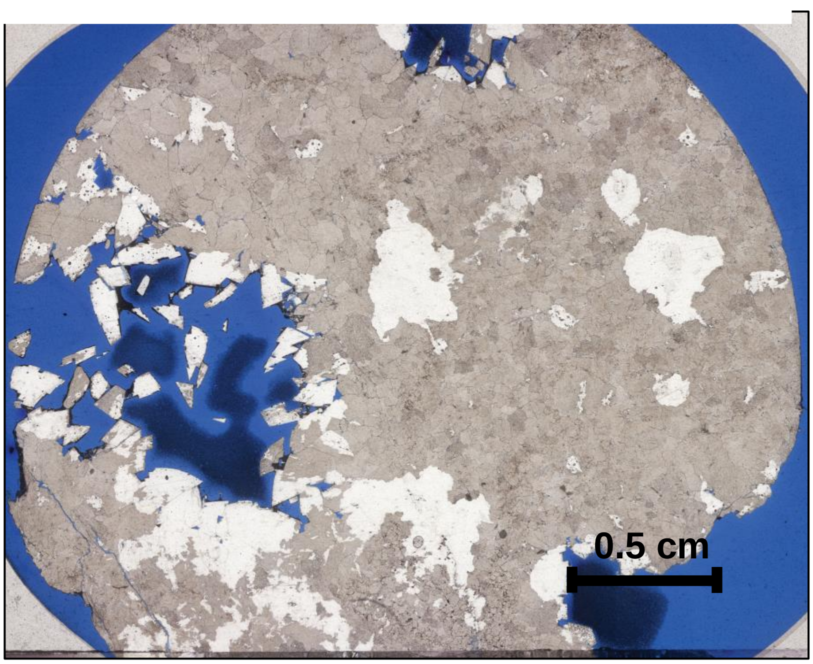

Figure 2

Acknowledgements

Geoscience BC, BC Hydro, BC Oil and Gas Commission, Canlin Energy, Husky Energy, SURGe research group at the University of Alberta, Natural Resources Canada Clean Energy for Rural and Remote Communities.

As a part of the University of Alberta's Future Energy Systems research initiative, this research was also made possible in part thanks to funding from the Canada First Research Excellence Fund.

Additional engineering feasibility work is funded under the Natural Resources Canada Clean Energy for Rural and Remote Communities.

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